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ITEM 1. BUSINESS A. GENERAL Alliant Energy maintains its principal executive offices in Madison, Wisconsin. Alliant Energy operates as a regulated investor-owned public utility holding company, and its purpose-driven strategy is to serve its customers and build stronger communities. Alliant Energys primary focus is to provide regulated electric and natural gas service to approximately 995,000 electric and approximately 425,000 natural gas customers in the Midwest through its two public utility subsidiaries, IPL and WPL. The primary first tier wholly-owned subsidiaries of Alliant Energy are as follows: 1) IPL - is a public utility engaged principally in the generation and distribution of electricity and the distribution and transportation of natural gas to retail customers in select markets in Iowa. IPL provides utility services to incorporated communities as directed by the IUB and utilizes non-exclusive franchises, which cover the use of public right-of-ways for utility facilities in incorporated communities for a maximum term of 25 years. At December 31, 2022, IPL supplied electric and natural gas service to approximately 500,000 and 225,000 retail customers, respectively, in Iowa. IPL also sells electricity to wholesale customers in Minnesota, Illinois and Iowa. IPL is also engaged in the generation and distribution of steam for two customers in Cedar Rapids, Iowa. 2) WPL - is a public utility engaged principally in the generation and distribution of electricity and the distribution and transportation of natural gas to retail customers in select markets in Wisconsin. WPL operates in municipalities pursuant to permits of indefinite duration and state statutes authorizing utility operation in areas annexed by a municipality. At December 31, 2022, WPL supplied electric and natural gas service to approximately 495,000 and 200,000 retail customers, respectively. WPL also sells electricity to wholesale customers in Wisconsin. 3) CORPORATE SERVICES - provides administrative services to Alliant Energy, IPL, WPL and AEF. 4) AEF - Alliant Energys non-utility holdings are organized under AEF, which manages a portfolio of wholly-owned subsidiaries and additional holdings, including the following distinct platforms: ATI - currently holds all of Alliant Energys interest in ATC Holdings. ATC Holdings is comprised of a 16% ownership interest in ATC and a 20% ownership interest in ATC Holdco LLC. ATC is an independent, for-profit, transmission-only company. ATC Holdco LLC holds an interest in Duke-American Transmission Company, LLC, a joint venture between Duke Energy Corporation and ATC, that owns electric transmission infrastructure in North America. ##TABLE_START 3 ##TABLE_ENDTable of Co ntents Corporate Venture Investments - includes various minority ownership interests in regional and national venture funds, including a global coalition of energy companies working together to help advance the transition towards a cleaner, more sustainable, and inclusive energy future, by identifying and researching innovative technologies and business models within the emerging energy economy. Non-utility Wind Farm - includes a 50% cash equity ownership interest in a 225 MW non-utility wind farm located in Oklahoma. Sheboygan Falls Energy Facility - is a 347 MW, simple-cycle, natural gas-fired EGU near Sheboygan Falls, Wisconsin, which is leased to WPL for an initial period of 20 years ending in 2025. Travero - is a diversified supply chain solutions company, including a short-line rail freight service in Iowa; a Mississippi River barge, rail and truck freight terminal in Illinois; freight brokerage services; and a rail-served warehouse in Iowa. B. INFORMATION RELATING TO ALLIANT ENERGY ON A CONSOLIDATED BASIS 1) HUMAN CAPITAL MANAGEMENT - Alliant Energys core purpose is to serve customers and build stronger communities. We constantly strive to attract, retain and develop a diverse and qualified workforce of high-performing employees, and create and foster an environment of inclusion and belonging for all employees. Employees - At December 31, 2022, Alliant Energy, IPL and WPL had the following full- and part-time employees: ##TABLE_START Total Number of Percentage of Employees Number of Bargaining Unit Covered by Collective Employees Employees Bargaining Agreements Alliant Energy 3,129 1,692 54% IPL 1,080 755 70% WPL 1,001 825 82% ##TABLE_ENDThe majority of IPLs bargaining unit employees are covered by the International Brotherhood of Electrical Workers Local 204 (Cedar Rapids) collective bargaining agreement, which expires August 31, 2024. All of WPLs bargaining unit employees are covered by the International Brotherhood of Electrical Workers Local 965 collective bargaining agreement, which expires May 31, 2026. Safety - Safety is integral to our companys culture. It is one of our Values - Live safety. Everyone. Always. Our first priority is that nobody gets hurt. Alliant Energy is committed to providing a safe environment for our employees, visitors, customers, contractors, vendors and the communities in which we live and work. We focus on the proactive management of our safety performance. Our comprehensive behavioral safety-based program consists of leading indicators, lagging indicators and targeted focus programs. We utilize a formal safety management system to capture and track best practices, near misses, job site briefings, safety observations, safety conversations and any unsafe conditions. This system provides the insights needed to help drive a positive safety culture and help ensure compliance with safety rules, processes and procedures. We also use this system to broadly share lessons learned in support of shaping the mindsets and behaviors needed to help prevent similar events from occurring elsewhere. Collectively, this information is used to evaluate the safety performance of the executive and management teams related to their goals, and safety metrics are factored into short-term incentive awards. We maintain executive and local safety leadership teams to establish our safety vision, strategy and priorities, and ensure education and recognition of employee actions that improve our safety culture. This leadership provides strong support for sustained growth of both employee and public safety programs and initiatives. Public safety is equally important as we interact with our customers to provide energy to their homes and businesses. We offer awareness campaigns, natural gas and electric public safety presentations, and free online resources and training programs and guidance to assist local emergency responders. Total Rewards - Our market-competitive Total Rewards programs are designed to meet the varied and evolving needs of our employees. Through a variety of health, welfare and compensation programs, we offer employees choice and control, while supporting their financial, physical, and mental well-being. Tools and resources are provided to employees to help maintain and improve their health. Short- and long-term incentive plans are designed with a mix of operational and financial metrics that align employees with strategic corporate and social goals. In addition to competitive salaries and wages, our Total Rewards programs include: competitive short- and long-term incentive compensation; a 401(k) savings plan with an employer match; healthcare and insurance benefits, including medical, vision, dental, life, short-term disability, and long-term disability insurance; ##TABLE_START 4 ##TABLE_ENDTable of Co ntents health savings and flexible spending accounts; paid time off to use for vacation, personal time, sick time, holidays, bereavement, jury duty, military leave, parental leave, maternity leave, and adoption leave; adoption assistance; legal planning assistance; Employee Assistance program; tuition reimbursement; Vacation Donation program; and Volunteer Grants and Matching Gifts program. Diversity, Equity and Inclusion (DEI) - A diverse, equitable and inclusive workplace is crucial for the success and retention of our employees, to attract future talent and to execute our purpose-driven strategy to serve our customers and build stronger communities. It is one of our Values - Care for others: Together we create a workplace where people feel like they belong and can use their unique backgrounds, talents and perspectives to their fullest potential. Alliant Energy is driven by DEI and believes the achievement of its strategic objectives can only be achieved with a focused and engaged workforce. Alliant Energys corporate officers group currently has approximately 40% gender diversity and 27% ethnic diversity. Our efforts to create a diverse and inclusive workforce have focused on reducing bias, building diverse teams, and listening and acting on employee feedback, and include: learning opportunities for employees, such as inviting employees to participate in area diversity summits and supporting company-wide listening sessions, speakers and programs; capturing and acting upon employee feedback through employee sentiment surveys; Employee Resource Groups that foster a diverse and inclusive workplace that supports employee well-being while promoting professional development and enhancing community relationships; and a DEI Leadership Team that partners with the Human Resources recruiting department and hiring managers to attract more diverse applicants that represent the diversity of the communities we serve. Our DEI initiatives also include a focus on building a diverse Board of Directors. We believe it is in our shareowners best interest to have a diverse Board representing a wide breadth of experiences and perspectives. Our Board currently has approximately 50% gender diversity and 20% ethnic diversity. Our 2022 DEI accomplishments include: received a perfect score on the Corporate Equality Index administered by the Human Rights Campaign Foundation to benchmark LGBTQ+ rights, policies and practices; selected for the 2022 Bloomberg Gender-Equality Index; held our third annual Day of Understanding, with 85% voluntary company-wide participation, where leaders facilitated conversations around creating a culture of inclusion and belonging, helping to ensure employees are seen, heard and valued; and all people-leaders completed training on reducing unconscious bias in the interview process. Alliant Energys short- and long-term incentive compensation plans include diversity metrics to drive leadership accountability for efforts to advance a diverse and inclusive culture. Talent Development and Workforce Readiness - We support employees in the growth of their careers through several training opportunities and development programs. These include tuition reimbursement, online, instructor-led and on-the-job learning formats, as well as leadership development and succession planning. In addition, we have an apprenticeship program that combines supervised, structured on-the-job training with related instruction to produce highly skilled trade and technical workers. Our program builds lifetime skills and comprehensive knowledge in the high-demand technical trades necessary for our success. The program gives us the flexibility to tailor training to match our needs - training employees in our facilities, on our equipment, and consistent with our safety standards and employee expectations. We instill company Values, methods and procedures from day one. 2) REGULATION - Alliant Energy, IPL and WPL are subject to regulation by various federal, state and local agencies. The following includes the primary regulations impacting Alliant Energys, IPLs and WPLs businesses. FERC - Public Utility Holding Company Act of 2005 - Alliant Energy is registered with FERC as a public utility holding company, pursuant to the Public Utility Holding Company Act of 2005, and is required to maintain certain records and to report certain transactions involving its public utilities, service company and other entities regulated by FERC.

Corporate Services, IPL and WPL are subject to regulation by FERC under the Public Utility Holding Company Act of 2005 for various matters including, but not limited to, affiliate transactions, public utility mergers, acquisitions and dispositions, and books, records and accounting requirements. ##TABLE_START 5 ##TABLE_ENDTable of Co ntents Energy Policy Act of 2005 - The Energy Policy Act of 2005 requires creation of an Electric Reliability Organization to provide oversight by FERC. FERC designated North American Electric Reliability Corporation as the overarching Electric Reliability Organization. Midwest Reliability Organization, which is a regional member of North American Electric Reliability Corporation, has direct responsibility for mandatory electric reliability standards for IPL and WPL. Federal Power Act of 1935 - FERC also has jurisdiction, under the Federal Power Act of 1935, over certain electric utility facilities and operations, electric wholesale sales, interstate electric transmission rates, dividend payments, issuance of IPLs securities, and accounting practices of Corporate Services, IPL and WPL. Electric Wholesale Rates - FERC has authority over IPL's and WPL's wholesale electric market-based rates. Market-based rate authorization allows for wholesale sales of electricity within FERCs wholesale markets, including the MISO market, and in transactions directly with third parties, based on the market value of the transactions. IPL and WPL also have FERC-approved cost of service formula-based rates related to the provision of firm full- and partial-requirement wholesale electric sales, which allow for true-ups to actual costs, including fuel costs. Electric Transmission Rates - FERC regulates the rates charged for electric transmission facilities used in interstate commerce. IPL and WPL do not own or operate FERC-regulated electric transmission facilities; however, both IPL and WPL pay for the use of the interstate electric transmission system based upon FERC-regulated rates. IPL and WPL rely primarily on the use of the ITC and ATC transmission systems, respectively. Natural Gas Act - FERC regulates the transportation and sale for resale of natural gas in interstate commerce under the Natural Gas Act. Under the Natural Gas Act, FERC has authority over certain natural gas facilities and operations of IPL and WPL. IUB - IPL is subject to regulation by the IUB for various matters including, but not limited to, retail utility rates and standards of service, accounting requirements, the construction of EGUs, and the acquisition, sale or lease of assets with values that exceed 3% of IPLs revenues. In 2021, legislation was enacted in Iowa prohibiting counties and cities from regulating the sale of natural gas and propane, which supports IPLs ability to provide gas utility service to a diversified base of retail customers and industries. Retail Utility Base Rates - IPL files periodic requests with the IUB for retail rate changes and may base those requests on either historical or forward-looking test periods. The IUB must decide on requests for retail rate changes within 10 months of the date of the application for which changes are filed. The historical test periods may be adjusted for certain known and measurable changes to capital investments, cost of capital and operating and maintenance expenses consistent with IUB rules and regulations. In 2021, the IUB adopted rules that establish minimum filing requirements for rate reviews using a forward-looking test period, and a related subsequent proceeding review after the close of the forward-looking test period. The rules provide that in the subsequent proceeding review, a utilitys actual costs and revenues will be presumed to be reasonably consistent with the forward-looking test period if the utilitys actual return on common equity falls within a standard of reasonableness of 50 basis points above to 50 basis points below the authorized return on common equity. If the utilitys actual return on common equity is outside of this range, future rates could be adjusted. In addition, the rules require that IPL must receive an order from the IUB related to the subsequent proceeding review before it can file another rate review. Energy Efficiency - In accordance with Iowa law, IPL is required to file an EEP every five years with the IUB. An EEP provides a utilitys plan and related budget to achieve specified levels of electric and gas energy savings. IUB approval demonstrates that IPLs EEP is reasonably expected to achieve cost-effective delivery of the energy efficiency programs. Refer to Note 1(g) for discussion of the recovery of these costs from IPLs retail electric and gas customers. Electric Generating Units - IPL must obtain a certificate of public convenience, use and necessity (GCU Certificate) from the IUB in order to construct a new, or significantly alter (including fuel switching) an existing, EGU located in Iowa with 25 MW or more of nameplate generating capacity. IPLs ownership and operation of EGUs (including those located outside the state of Iowa) to serve Iowa customers is subject to retail utility rate regulation by the IUB. Gas Pipeline Projects - IPL must obtain a pipeline permit from the IUB related to the siting of utility gas pipelines in Iowa that will be operated at a pressure over 150 pounds per square inch and will transport gas to a distribution system or single, large volume customer. Advance Rate-making Principles - Iowa law allows Iowa utilities to request rate-making principles prior to making certain generation investments in Iowa. As a result, IPL may file for, and the IUB must render a decision on, rate-making principles for certain new EGUs located in Iowa, including any alternative energy production facility (such as a wind or solar facility, as well as battery storage constructed in combination with these facilities), combined-cycle natural gas-fired EGU, and certain base-load EGUs with a nameplate generating capacity of 300 MW or more (such as nuclear-fired generation). Stand-alone battery storage facilities will be considered for advance rate-making principles on a case-by-case basis. Advance rate-making principles are also available for the repowering of an alternative energy production facility or certain significant alterations of an existing EGU. Upon approval of rate-making principles by the IUB, IPL must either construct the EGU or repower the alternative energy production facility under the approved rate-making principles, or not at all. If rate-making principles are not ##TABLE_START 6 ##TABLE_ENDTable of Co ntents approved by the IUB, IPL may construct the facility, subject to other applicable approvals (such as a GCU Certificate), subject to recovery in future rate reviews. Electric Generating Unit Environmental Controls Projects - IPL is required to submit an updated emissions plan and budget biennially to the IUB setting out a multi-year plan and budget for managing regulated emissions from its coal-fired EGUs in a cost-effective manner. IPL must simultaneously submit this plan and budget to the Iowa Department of Natural Resources for a determination of whether the plan and budget meet state environmental requirements for regulated emissions. The reasonable and prudent costs associated with implementing the approved plan are expected to be included in IPLs future retail electric rates. PSCW - WPL is subject to regulation by the PSCW related to its operations in Wisconsin for various matters including, but not limited to, retail utility rates and standards of service, accounting requirements, issuance and use of proceeds of securities, affiliate transactions, approval of the location and construction of EGUs and certain other additions and extensions to facilities. In addition, Alliant Energy is subject to regulation by the PSCW for the type and amount of Alliant Energys holdings in non-utility businesses and other affiliated interest activities, among other matters. Retail Utility Base Rates - WPL files periodic requests with the PSCW for retail rate changes, which are based on forward-looking test periods. There is no statutory time limit for the PSCW to decide on retail base rate requests. However, the PSCW attempts to process retail base rate reviews in approximately 10 months and has the ability to approve interim retail rate relief, subject to refund, if necessary. Currently, WPL is required to defer a portion of its earnings if its annual regulatory return on common equity exceeds certain levels. Through 2023, any such deferral is required to be offset against the remaining net book value of Edgewater Unit 5, which is currently expected to be retired by June 1, 2025. Public Benefits - WPL contributes 1.2% of its annual retail utility revenues to help fund Focus on Energy, Wisconsins state-wide energy efficiency and renewable energy resource program. In addition, WPL contributes to a program that provides assistance to income-eligible residents in Wisconsin. These contributions are recovered from customers through a monthly bill surcharge of the lesser of 3% of customers utilities bills or $750. Refer to Note 1(g) for discussion of the recovery of these costs from WPLs retail electric and gas customers. New Electric Generating Units - A CA application is required to be filed with the PSCW for construction approval of any new EGU (including battery storage) with a capacity of less than 100 MW and a project cost of $12.4 million or more. WPL must obtain a CPCN from the PSCW in order to construct a new EGU in Wisconsin with a capacity of 100 MW or more. In addition, WPLs ownership and operation of EGUs (including those located outside the state of Wisconsin) to serve Wisconsin customers are subject to retail utility rate regulation by the PSCW. Electric Generating Unit Upgrades and Electric Distribution Projects - A CA application is required to be filed with the PSCW for construction approval of any additions to EGUs, including environmental controls projects, as well as electric distribution projects, with estimated project costs of $12.4 million or more. Gas Distribution Projects - A CA application is required to be filed with the PSCW for construction approval of gas projects with an estimated project cost of $5.9 million or more and at any time that WPL requests to extend gas service to a new portion of its service territory. Advance Rate-making Principles - Wisconsin law provides Wisconsin utilities with the opportunity to request rate-making principles prior to the purchase or construction of any EGU utilized to serve Wisconsin customers. WPL is not obligated to file for or accept authorized rate-making principles under Wisconsin law. WPL can proceed with an approved project under traditional rate-making terms or accept authorized rate-making principles under Wisconsin law. Department of Homeland Security Transportation Security Administration - Alliant Energy, IPL and WPL are subject to regulation for physical and cyber security of their natural gas pipeline systems, and are applying, and monitoring for changes to, these requirements to their pipeline systems. Environmental - Alliant Energy, IPL and WPL are subject to regulation of environmental matters by federal, state and local authorities as a result of their current and past operations. Alliant Energy, IPL and WPL monitor these environmental matters and address them by installing controls that reduce emissions and by implementing operational modifications or other measures to address compliance obligations. There is currently significant regulatory uncertainty with respect to environmental rules and regulations discussed below. Given the evolving nature of environmental regulations and other related regulatory requirements, Alliant Energy, IPL and WPL develop and periodically update their compliance plans to address these environmental obligations. Prudent expenditures incurred by IPL and WPL to comply with environmental requirements are eligible to be recovered in rates from their customers. The following are major environmental matters that could potentially have a significant impact on financial condition and results of operations. ##TABLE_START 7 ##TABLE_ENDTable of Co ntents Air Quality - Climate Change and Greenhouse Gas Regulations - In 2007, the Supreme Court provided direction on the EPAs authority to regulate GHG and ruled that these emissions are covered by the CAA. In 2009, the EPA issued a ruling that found GHG emissions contribute to climate change, and therefore, threaten public health and welfare, which was the prerequisite for implementing CO2 reduction standards under the CAA. While the EPAs rules to regulate GHG issued under the authority of the CAA remain subject to further review, growing emphasis on climate change and evolving energy technologies are driving efforts to decarbonize the environment through voluntary emissions reductions. The primary GHG directly emitted from Alliant Energys utility operations is CO2 from the combustion of fossil fuels at its EGUs. Clean Air Act Section 111(d) - In 2015, the EPA issued the Clean Power Plan under Section 111(d) of the CAA to reduce CO2 emissions from existing fossil-fueled EGUs through broad electricity system-wide measures. This was replaced by the Affordable Clean Energy rule in 2019, to reduce CO2 emissions from existing coal-fueled EGUs through heat rate improvements. In 2021, the U.S. Court of Appeals for the District of Columbia Circuit vacated and remanded the Affordable Clean Energy rule to the EPA for reconsideration. In 2022, the Supreme Court issued a ruling limiting the extent of the EPAs authority under Section 111(d) to emissions reduction technologies and operational improvements. The EPA is working on a new set of Section 111(d) emission guidelines for states to implement Best System of Emission Reduction standards for GHG emissions from existing fossil-fueled EGUs, and has stated that it intends to issue a proposed rule in 2023 and a final rule in 2024, although a timeline cannot be predicted with certainty. Alliant Energy, IPL and WPL are currently unable to predict with certainty the future outcome or impact of these matters. Clean Air Act Section 111(b) - In 2015, the EPA published final standards under Section 111(b) of the CAA, which establish CO2 emissions limits for certain new fossil-fueled EGUs. Marshalltown and West Riverside are subject to the EPAs Section 111(b) regulation and have been designed to achieve compliance with these standards. The EPA is reviewing the Section 111(b) standards, and has stated it intends to issue a proposed rule in 2023 and a final rule in 2024, although a timeline cannot be predicted with certainty. Litigation related to Section 111(b) is suspended while the EPA revises its Section 111(b) regulations, and Alliant Energy, IPL and WPL are currently unable to predict with certainty the impact of these standards. Cross-State Air Pollution Rule - CSAPR is a regional sulfur dioxide and nitrogen oxides cap-and-trade program, where compliance with emission limits may be achieved by purchasing emission allowances and/or reducing emissions through changes in operations or the additions of environmental controls. CSAPR emission allowances may be banked for future year compliance. CSAPR establishes state-specific annual sulfur dioxide and nitrogen oxides emission caps and ozone season nitrogen oxides emission caps. In 2022, the EPA proposed revisions to the CSAPR state-specific ozone season nitrogen oxides emission caps and utility-specific emission allowances for certain states, including Wisconsin, beginning in 2023. The proposed rule does not apply to Iowa; however, Iowa could be included in the final rule, which is currently expected in 2023. Alliant Energy, IPL and WPL are currently unable to predict with certainty the future outcome or impact of these matters. Water Quality - Effluent Limitation Guidelines - In 2015, the EPA published final effluent limitation guidelines, which required changes to discharge limits for wastewater from certain IPL and WPL steam EGUs. In 2020, revised effluent limitation guidelines (2020 Reconsideration Rule) became effective, which incorporated flexibility to the 2015 rule, including a new subcategory for coal-fired EGUs that will be retired or converted to no longer burn coal before 2028. Compliance for existing steam-electric generating facilities is determined by each facilitys wastewater discharge permit and will generally be required by December 31, 2025. Projects required for compliance are facility-specific. In 2021, the current Presidential Administration issued an Executive Order requiring the review and possible revision of environmental regulations issued during the prior Administration. As a result, the EPA expects to undertake a supplemental rule-making to revise the guidelines for steam-electric generating facilities. As part of the rule-making process, the EPA is expected to determine whether more stringent limitations and standards are appropriate. The 2020 Reconsideration Rule will remain in effect while the EPA undertakes this new rule-making. Alliant Energy, IPL and WPL are currently unable to predict with certainty the future outcome or impact of the anticipated supplemental rule-making. Land and Solid Waste - Coal Combustion Residuals Rule - The CCR Rule, which became effective in 2015, regulates CCR as a non-hazardous waste. IPL and WPL have coal-fired EGUs with coal ash ponds and active CCR landfills that are impacted by this rule. Compliance obligations associated with the CCR Rule may be subject to change due to future EPA CCR Rule updates, on-going litigation related to the CCR Rule, and any actions taken to-date that may be challenged. Alliant Energy, IPL and WPL are currently unable to predict with certainty the impact of these updates. Manufactured Gas Plant Sites - Refer to Note 17(e) for discussion of IPLs and WPLs MGP sites. Renewable Energy Standards - Iowa and Wisconsin have renewable energy standards, which establish the minimum amount of energy IPL and WPL must supply from renewable resources. IPL primarily relies upon renewable energy generated from the wind resources it owns and renewable energy acquired under PPAs to meet these requirements. WPL utilizes its current renewable portfolio, which primarily consists of wind, solar and hydro energy, both owned and acquired under PPAs, to meet these requirements. IPL and WPL currently exceed their respective renewable energy standards requirements. ##TABLE_START 8 ##TABLE_ENDTable of Co ntents 3) STRATEGY - Refer to Overview in MDA for discussion of Alliant Energys strategy, which supports its mission to deliver energy solutions and exceptional service that its customers and communities count on - affordably, safely, reliably and sustainably. C. INFORMATION RELATING TO UTILITY OPERATIONS Alliant Energys utility business (IPL and WPL) has three segments: a) electric operations; b) gas operations; and c) other, which includes IPLs steam operations and the unallocated portions of the utility business. IPLs and WPLs electric, gas and other revenues as a percentage of total revenues were as follows: ##TABLE_START IPL WPL ##TABLE_END1) ELECTRIC UTILITY OPERATIONS General - Electric utility operations represent the largest operating segment for Alliant Energy, IPL and WPL. Alliant Energys electric utility operations are located in the Midwest with IPL providing retail electric service in Iowa and WPL providing retail and wholesale electric service in Wisconsin. IPL also sells electricity to wholesale customers in Minnesota, Illinois and Iowa. Refer to the Electric Operating Information tables for additional details regarding electric utility operations. Customers - IPL and WPL provide electric utility service to a diversified base of retail customers in several industries, with the largest concentrations in the farming, agriculture, industrial manufacturing, chemical (including ethanol), packaging and food industries. IPL and WPL also sell electricity to wholesale customers, which primarily consist of municipalities and rural electric cooperatives. Seasonality - Electric sales are seasonal to some extent with the annual peak normally occurring in the summer months due to air conditioning requirements. Electric sales are also impacted to a certain extent in the winter months due to heating requirements. Competition - Retail electric customers in Iowa and Wisconsin currently do not have the ability to choose their electric supplier, and IPL and WPL have obligations to serve all their retail electric customers. Although electric service in Iowa and Wisconsin is regulated, IPL and WPL still face competition from self-generation by large industrial customers, customer- and third party-owned generation (e.g. solar panels), alternative energy sources, and petitions to municipalize (Iowa) as well as service territory expansions by municipal utilities through annexations (Wisconsin). In addition, the wholesale power market is competitive and IPL and WPL compete against independent power producers, other utilities and MISO market purchases to serve wholesale customers for their electric energy and capacity needs. Alliant Energys strategy includes actions to retain current customers and attract new customers into IPLs and WPLs service territories in an effort to keep energy rates low for all of their customers. Refer to Overview in MDA for discussion of the strategy element focusing on growing customer demand. Electric Supply - Alliant Energy, IPL and WPL have met, and expect to continue meeting, customer demand of electricity through a mix of electric supply, including owned EGUs, PPAs and additional purchases from wholesale energy markets. Alliant Energy expects its mix of electric supply to change in the next several years with its planned transition away from coal-fired EGUs by considering additional renewable energy such as solar generation, repowering of existing wind farms and distributed energy resources, including community solar and energy storage systems, natural gas resources, and the actual and potential sale of partial interests in West Riverside to neighboring utilities. Long-term generation plans are intended to meet customer demand, reduce air emissions and water impacts, reduce reliance on wholesale market purchases and mitigate the impacts of future EGU retirements while maintaining compliance with long-term electric demand planning reserve margins, renewable energy standards established by regulators and other various requirements. Electric Demand Planning Reserve Margin - IPL and WPL are required to maintain a planning reserve margin above their load at the time of the MISO-wide peak to ensure reliability of electric service to their customers. IPL and WPL utilize accredited capacity from EGUs they own, and have rights to through PPAs, to meet a substantial portion of their current MISO planning reserve margin requirements and periodically rely on short-term market capacity purchases to supplement the accredited capacity from such EGUs. Refer to Customer Investments in MDA for discussion of MISOs new seasonal resource adequacy process establishing capacity planning reserve margin and capacity accreditation requirements effective with the June 1, 2023 through May 31, 2024 MISO Planning Year. The new seasonal capacity reserve margins are as follows: ##TABLE_START 9 ##TABLE_ENDTable of Co ntents ##TABLE_START June 2023 - August 2023 September 2023 - November 2023 December 2023 - February 2024 March 2024 - May 2024 Required installed capacity reserve margin 15.9% 25.8% 41.2% 39.3% Required unforced capacity reserve margin 7.4% 14.9% 25.5% 24.5% ##TABLE_ENDGeneration Fuel Supply - IPL and WPL own a portfolio of EGUs located in Iowa, Wisconsin and Minnesota with a diversified fuel mix that includes natural gas, renewable resources and coal. Refer to Properties in Item 2 for details of IPLs and WPLs EGUs. The average cost of delivered fuel per million British Thermal Units used for electric generation was as follows: ##TABLE_START IPL WPL 2022 2021 2020 2022 2021 2020 All fuels $4.37 $2.10 $2.22 $4.47 $2.62 $2.36 Natural gas (a) 5.76 2.54 2.54 6.02 3.31 2.51 Coal 2.31 1.81 1.84 2.43 2.07 2.19 ##TABLE_END(a) The average cost of natural gas includes commodity and transportation costs, as well as realized gains and losses from swap and option contracts used to hedge the price of natural gas volumes expected to be used by IPLs and WPLs natural gas-fired EGUs. Natural Gas - Alliant Energy, IPL and WPL own several natural gas-fired EGUs, and WPL also has exclusive rights to the output of AEFs Sheboygan Falls Energy Facility under an affiliated lease agreement. These facilities help meet customer demand for electricity when natural gas prices are low enough to make natural gas-fired generation economical compared to other fuel sources. Alliant Energy manages the gas supply to these gas-fired EGUs and helps ensure an adequate supply is available at known prices through a combination of gas commodity, pipeline transportation and storage agreements held by IPL and WPL for numerous years. Alliant Energy, IPL and WPL believe they are reasonably insulated against gas price volatility for these EGUs given their use of forward contracts and hedging practices, as well as their regulatory cost-recovery mechanisms. Coal - Coal is one of the fuel sources for owned EGUs. Coal contracts entered into with different entities help ensure that a specified supply of coal is available, and delivered, at known prices for IPLs and WPLs coal-fired EGUs. Alliant Energy, IPL and WPL believe their coal supply portfolio represents a reasonable balance between the risks of insufficient supplies and those associated with being unable to respond to future coal market changes. Remaining coal requirements are expected to be met from either future term contracts or purchases in the spot market. Currently, all of the coal utilized by IPL and WPL is from the Wyoming Powder River Basin. Alliant Energy, IPL and WPL believe they are reasonably insulated against coal price volatility given their current coal procurement process, the specific coal market in their primary purchase region and regulatory cost-recovery mechanisms. The coal procurement process supports periodic purchases, staggering of contract terms, stair-stepped levels of supply going forward and supplier diversity. Similarly, given the term lengths of their transportation agreements and strategic alignment of agreement expirations for negotiation purposes, Alliant Energy, IPL and WPL believe they are reasonably insulated against future higher coal transportation rates from the major railroads. Purchased Power - IPL and WPL periodically enter into PPAs and purchase electricity from wholesale energy markets to meet a portion of their customer demand for electricity. Electric Transmission - IPL and WPL do not own electric transmission service assets and currently receive transmission services from ITC and ATC, respectively. ITC and ATC are independent, for-profit, transmission-only companies and are transmission-owning members of the MISO Regional Transmission Organization, Midwest Reliability Organization and Reliability First Corporation Regional Entities. The annual transmission service rates that ITC or ATC charges their customers are calculated each calendar year using a FERC-approved cost of service formula rate. As a result, ITC and ATC can implement new rates each calendar year without filing a request with FERC. However, new rates are subject to challenge by either FERC or customers. If the rates proposed by ITC or ATC are determined by FERC to be unjust or unreasonable, or another mechanism is determined by FERC to be just and reasonable, ITCs or ATCs rates would change accordingly. Refer to Note 1(g) for discussion of a transmission cost rider utilized by IPL for recovery of its electric transmission service expense, and discussion of WPLs escrow for recovery of electric transmission service expense, which is recovered from its retail electric customers through changes in base rates determined during periodic rate proceedings. Refer to Note 17(g) for discussion of a court decision, which is currently expected to reduce the base return on equity authorized for MISO transmission owners, including ATC. ##TABLE_START 10 ##TABLE_ENDTable of Co ntents MISO Markets - IPL and WPL are members of MISO, a FERC-approved Regional Transmission Organization, which is responsible for monitoring and ensuring equal access to the transmission system in their footprint. IPL and WPL participate in the wholesale energy and ancillary services markets operated by MISO, which are discussed in more detail below. As agent for IPL and WPL, Corporate Services enters into energy, capacity, ancillary services, and transmission sale and purchase transactions within MISO. Corporate Services assigns such sales and purchases between IPL and WPL based on statements received from MISO. Wholesale Energy Market - IPL and WPL sell and purchase power in the day-ahead and real-time wholesale energy markets operated by MISO. MISOs bid/offer-based markets compare the cost of IPL and WPL generation against other generators, which affects IPL and WPL generation operations, energy purchases and energy sales. MISO generally dispatches the lowest cost generators, while recognizing current system constraints, to reduce costs for purchasers in the wholesale energy market. In addition, MISO may dispatch generators that support reliability needs, but that would not have operated based on economic needs. In these cases, MISOs settlement assures that these generators are made whole financially for their variable costs. Ancillary Services Market - IPL and WPL also participate in MISOs ancillary services market, which integrates the procurement and use of regulation and contingency reserves with the existing wholesale energy market to ensure reliability of electricity supply. MISOs ancillary services market has had the overall impact of lowering ancillary services costs in the MISO footprint. Financial Transmission Rights and Auction Revenue Rights - In areas of constrained transmission capacity, energy costs could be higher due to congestion and its impact on locational marginal prices. FTRs provide a hedge for certain congestion costs that occur in the MISO energy market. MISO allocates auction revenue rights to IPL and WPL annually based on a fiscal year from June 1 through May 31 and historical use of the transmission system. The allocated auction revenue rights are used by IPL and WPL to acquire FTRs through the FTR auctions operated by MISO. Resource Adequacy - MISO has resource adequacy requirements to help ensure adequate resources to meet forecasted peak load obligations plus a reserve margin. Only accredited capacity assigned to EGUs is available to meet these requirements. In order for an EGU to receive accredited capacity, it must meet MISO capacity accreditation requirements, which can include satisfying transmission requirements identified in its interconnection agreement prior to the MISO planning year. Refer to Customer Investments in MDA for discussion of MISOs new seasonal resource adequacy process establishing capacity planning reserve margin and capacity accreditation requirements effective with the 2023/2024 MISO Planning Year. ##TABLE_START 11 ##TABLE_ENDTable of Co ntents ##TABLE_START Electric Operating Information - Alliant Energy 2022 2021 2020 Revenues (in millions): Residential $1,233 $1,115 $1,093 Commercial 821 763 718 Industrial 965 893 841

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Retail subtotal 3,019 2,771 2,652 Sales for resale: Wholesale 233 187 168 Bulk power and other 111 56 36 Other 58 67 64 Total $3,421 $3,081 $2,920 Sales (000s MWh): Residential 7,479 7,353 7,294 Commercial 6,436 6,383 6,107 Industrial 11,494 11,696 11,134 Retail subtotal 25,409 25,432 24,535 Sales for resale: Wholesale 2,866 2,787 2,525 Bulk power and other 3,734 3,018 3,521 Other 62 71 71 Total 32,071 31,308 30,652 Customers (End of Period): Retail 989,369 981,570 974,144 Other 2,903 2,878 2,841 Total 992,272 984,448 976,985 Other Selected Electric Data: Maximum summer peak hour demand (MW) 5,629 5,486 5,496 Maximum winter peak hour demand (MW) 4,415 4,413 4,158 Cooling degree days (a): Cedar Rapids, Iowa (IPL) (normal - 807) 908 974 800 Madison, Wisconsin (WPL) (normal - 695) 787 845 736 Sources of electric energy (000s MWh): Gas 11,438 10,055 10,440 Purchased power: Wind (b) 4,422 3,529 3,683 Nuclear 2,347 Other (b) 2,803 2,642 2,521 Wind (b) 6,424 5,231 4,872 Coal 7,416 10,218 7,021 Other (b) 239 226 254 Total 32,742 31,901 31,138 Revenue per KWh sold to retail customers (cents) 11.88 10.90 10.81 ##TABLE_END(a) Cooling degree days are calculated using a simple average of the high and low temperatures each day compared to a 65 degree base. Normal degree days are calculated using a rolling 20-year average of historical cooling degree days. Refer to Gas Operating Information below for details of heating degree days. (b) All or some of the renewable energy attributes associated with generation from these sources may be used in future years to comply with renewable energy standards or other regulatory requirements. ##TABLE_START 12 ##TABLE_ENDTable of Co ntents ##TABLE_START Electric Operating Information IPL WPL 2022 2021 2020 2022 2021 2020 Revenues (in millions): Residential $673 $620 $602 $560 $495 $491 Commercial 536 508 474 285 255 244 Industrial 538 505 488 427 388 353 Retail subtotal 1,747 1,633 1,564 1,272 1,138 1,088 Sales for resale: Wholesale 64 57 57 169 130 111 Bulk power and other 13 17 31 98 39 5 Other 35 45 43 23 22 21 Total $1,859 $1,752 $1,695 $1,562 $1,329 $1,225 Sales (000s MWh): Residential 3,793 3,680 3,623 3,686 3,673 3,671 Commercial 4,049 4,022 3,835 2,387 2,361 2,272 Industrial 6,428 6,581 6,372 5,066 5,115 4,762 Retail subtotal 14,270 14,283 13,830 11,139 11,149 10,705 Sales for resale: Wholesale 771 738 723 2,095 2,049 1,802 Bulk power and other 1,401 1,069 2,762 2,333 1,949 759 Other 33 35 34 29 36 37 Total 16,475 16,125 17,349 15,596 15,183 13,303 Customers (End of Period): Retail 498,515 496,435 494,258 490,854 485,135 479,886 Other 867 858 856 2,036 2,020 1,985 Total 499,382 497,293 495,114 492,890 487,155 481,871 Other Selected Electric Data: Maximum summer peak hour demand (MW) 2,895 2,892 2,951 2,800 2,680 2,609 Maximum winter peak hour demand (MW) 2,449 2,433 2,311 2,046 2,028 1,873 Cooling degree days (a): Cedar Rapids, Iowa (IPL) (normal - 807) 908 974 800 N/A N/A N/A Madison, Wisconsin (WPL) (normal - 695) N/A N/A N/A 787 845 736 Sources of electric energy (000s MWh): Gas 4,625 4,011 5,296 6,813 6,044 5,144 Purchased power: Wind (b) 2,985 2,285 2,359 1,437 1,244 1,324 Nuclear 2,347 N/A N/A N/A Other (b) 835 1,166 391 1,968 1,476 2,130 Wind (b) 4,991 4,088 3,843 1,433 1,143 1,029 Coal 3,305 4,756 3,185 4,111 5,462 3,836 Other (b) 13 12 12 226 214 242 Total 16,754 16,318 17,433 15,988 15,583

Ticker: LNT, Sector: Utilities, Filed At: 2023-02-24T16:03:25-05:00

13,705 Revenue per KWh sold to retail customers (cents) 12.24 11.43 11.31 11.42 10.21 10.16 ##TABLE_END(a) Cooling degree days are calculated using a simple average of the high and low temperatures each day compared to a 65 degree base. Normal degree days are calculated using a rolling 20-year average of historical cooling degree days. Refer to Gas Operating Information below for details of heating degree days. (b) All or some of the renewable energy attributes associated with generation from these sources may be used in future years to comply with renewable energy standards or other regulatory requirements. ##TABLE_START 13 ##TABLE_ENDTable of Co ntents 2) GAS UTILITY OPERATIONS General - Gas utility operations represent the second largest operating segment for Alliant Energy, IPL and WPL. Alliant Energys gas utility operations are located in the Midwest with IPL providing gas service in Iowa and WPL providing gas service in Wisconsin. Refer to the Gas Operating Information tables for additional details regarding gas utility operations. Refer to Note 1(g) for information relating to utility natural gas cost recovery mechanisms and Note 17(b) for discussion of natural gas commitments. Customers - IPL and WPL provide gas utility service to a diversified base of retail customers and industries, including research, education, hospitality, manufacturing and chemicals (including ethanol). In addition, IPL and WPL provide transportation service to commercial and industrial customers by moving customer-owned gas through Alliant Energys distribution systems to the customers meters. Seasonality - Gas sales follow a seasonal pattern with an annual base-load of gas and a large heating peak occurring during the winter season. Natural gas obtained from producers, marketers and brokers, as well as gas in storage, is utilized to meet the peak heating season requirements. Storage contracts generally allow IPL and WPL to purchase gas in the summer and inject it into underground storage fields, and remove it from storage fields in the winter to deliver to customers. Competition - Gas customers in Iowa and Wisconsin currently do not have the ability to choose their gas distributor, and IPL and WPL have obligations to serve all their gas customers. While the gas utility distribution function is expected to remain a regulated function, sales of the natural gas commodity and related services are subject to competition from third-parties who provide alternative fuel sources (e.g. propane). However, when natural gas service is available for a given area, customers in such area have generally selected natural gas over propane as a more cost competitive solution for their fuel needs. Refer to Customer Investments in MDA for discussion of plans to expand gas distribution systems. Gas Supply - IPL and WPL maintain purchase agreements with numerous suppliers of natural gas from various gas producing regions of the U.S. and Canada. In providing gas commodity service to retail customers, Corporate Services administers a diversified portfolio of transportation and storage contracts on behalf of IPL and WPL. The tariffs for IPLs and WPLs retail gas customers provide for subsequent adjustments to their rates for the cost of gas sold to these customers. As a result, natural gas prices do not have a material impact on IPLs or WPLs gas margins. Gas Demand Planning Reserve Margin - IPL and WPL are required to maintain adequate pipeline capacity to ensure they meet their customers maximum daily system demand requirements. IPL and WPL currently have planning reserve margins of 2% and 6%, respectively, above their forecasted maximum daily system demand requirements from November 2022 through March 2023. ##TABLE_START Gas Operating Information - Alliant Energy 2022 2021 2020 Revenues (in millions): Residential $371 $257 $214 Commercial 197 139 107 Industrial 20 17 12 Retail subtotal 588 413 333 Transportation/other 54 43 40 Total $642 $456 $373 Sales (000s Dths): Residential 31,109 26,795 27,809 Commercial 21,097 18,516 17,996 Industrial 2,815 2,868 3,003 Retail subtotal 55,021 48,179 48,808 Transportation/other 104,812 99,179 102,790 Total 159,833 147,358 151,598 Retail Customers (End of Period) 426,153 422,864 419,994 Other Selected Gas Data: Heating degree days (a): Cedar Rapids, Iowa (IPL) (normal - 6,697) 7,222 6,539 6,625 Madison, Wisconsin (WPL) (normal - 6,976) 7,210 6,620 6,789 Revenue per Dth sold to retail customers $10.69 $8.57 $6.82 Purchased gas costs per Dth sold to retail customers $6.97 $5.29 $3.67 ##TABLE_END##TABLE_START 14 ##TABLE_ENDTable of Co ntents ##TABLE_START Gas Operating Information IPL WPL 2022 2021 2020 2022 2021 2020 Revenues (in millions): Residential $202 $146 $116 $169 $111 $98 Commercial 101 79 59 96 60 48 Industrial 14 12 8 6 5 4 Retail subtotal 317 237 183 271 176 150 Transportation/other 34 28 25 20 15 15 Total $351 $265 $208 $291 $191 $165 Sales (000s Dths): Residential 16,250 13,873 14,521 14,859 12,922 13,288 Commercial 10,257 9,065 8,925 10,840 9,451 9,071 Industrial 1,985 1,943 2,062 830 925 941 Retail subtotal 28,492 24,881 25,508 26,529 23,298 23,300 Transportation/other 43,264 40,738 39,543 61,548 58,441 63,247 Total 71,756 65,619 65,051 88,077 81,739 86,547 Retail Customers (End of Period) 226,284 225,517 224,927 199,869 197,347 195,067 Other Selected Gas Data: Maximum daily winter peak demand (Dth) 259,474 269,335 253,439 201,980 221,256 189,439 Heating degree days (a): Cedar Rapids, Iowa (IPL) (normal - 6,697) 7,222 6,539 6,625 N/A N/A N/A Madison, Wisconsin (WPL) (normal - 6,976) N/A N/A N/A 7,210 6,620 6,789 Revenue per Dth sold to retail customers $11.13 $9.53 $7.17 $10.22 $7.55 $6.44 Purchased gas cost per Dth sold to retail customers $7.17 $5.96 $3.87 $6.77 $4.58 $3.45 ##TABLE_END(a) Heating degree days are calculated using a simple average of the high and low temperatures each day compared to a 65 degree base. Normal degree days are calculated using a rolling 20-year average of historical heating degree days. 3) OTHER UTILITY OPERATIONS - STEAM - IPLs Prairie Creek facility is the primary source of steam for IPLs two high-pressure steam customers in Iowa. These customers are each under contract through 2025 for taking minimum quantities of annual steam usage, with certain conditions. ITEM 1A. RISK FACTORS You should carefully consider each of the risks described below relating to Alliant Energy, IPL and WPL, together with all of the other information contained in this combined report, before making an investment decision with respect to our securities. If any of the following risks develop into actual events, our business, financial condition or results of operations could be materially and adversely affected, and you may lose all or part of your investment. Risks Related to Business Operations A cyber attack may disrupt our operations or lead to a loss or misuse of confidential and proprietary information or potential liability - We operate in an industry that requires the continuous use and operation of sophisticated information technology systems and network infrastructure. We face threats from use of malicious code (such as malware, viruses and ransomware), employee theft or misuse, advanced persistent threats, vulnerabilities such as the log4j vulnerability, fraud attempts, and phishing attacks. More of our workforce is working remotely, which increases the number of devices connected to the internet that impact our operations and increases our cyber security risk. Incidents of ransomware attacks have been increasing in frequency and magnitude, including the ransomware attack that resulted in the operator of the Colonial Pipeline paying millions of dollars in ransom to hackers as a result of a cyber attack disabling the pipeline for several days in 2021. Cyber attacks targeting electronic control systems used at our generating facilities and for electric and gas distribution systems could result in a full or partial disruption of our electric and/or gas operations. We have relied on a global supply chain for certain components of our operating and technology systems, which may increase our exposure to cyber attacks. Any disruption of these operations could result in a loss of service to customers and a significant decrease in revenues, as well as significant expense to repair system damage and remedy security breaches. Due to the evolving nature of cyber attacks and cyber security, our current safeguards to protect our operating systems and information technology assets may not always be effective. We rely on third parties for software to protect against cyber attacks and we are at risk if such third parties are targets of cyber attacks. If the technology systems were to fail or be breached by a cyber attack or a computer virus, and not be recovered in a timely fashion, we may be unable to fulfill critical business functions and confidential data could be compromised, adversely impacting our financial condition and results of operation. In addition, we may collect and retain sensitive information, including personal information about our customers, shareowners and employees. In some cases, we outsource administration of certain functions to vendors that could be targets of cyber ##TABLE_START 15 ##TABLE_ENDTable of Co ntents attacks. For example, we outsource administration of our employee health insurance to Anthem, which was the target of a cyber attack in 2014. Any theft, loss and/or fraudulent use of customer, shareowner, employee or proprietary data as a result of a cyber attack could subject us to significant litigation, liability and costs, as well as adversely impact our reputation with customers and regulators, among others. Demand for energy may decrease - Our results of operations are affected by the demand for energy in our service territories. Energy demand may decrease due to many things, including proliferation of customer and third party-owned generation, technological advances that reduce the costs of renewable energy and storage solutions for our customers, government policies, such as the Inflation Reduction Act of 2022, which incentivize customer and third party-owned generation, loss of service territory or franchises, energy efficiency measures, technological advances that improve energy efficiency, third-party disrupters, loss of wholesale customers, the adverse impact of tariffs on our customers, and economic conditions. The loss of sales due to lower demand for energy may increase our rates for remaining customers, as our rates must cover our fixed costs. Increased customer rates may cause decreased demand for energy as customers move to customer and third party-owned generation and implement energy efficiency measures to reduce costs. The loss of customers, the inability to replace those customers with new customers, and the decrease in demand for energy could negatively impact our financial condition and results of operations. Our strategy includes large construction projects, which are subject to risks - Our strategy includes constructing renewable generating facilities and large-scale additions and upgrades to our electric and gas distribution systems. These construction projects are subject to various risks. These risks include: the inability to obtain necessary regulatory approvals and permits in a timely manner; adverse interpretation or enforcement of permit conditions; changes in applicable laws or regulations; changes in costs of materials, equipment, commodities, fuel or labor including due to inflation, tariffs, labor issues, or supply shortages; delays caused by construction accidents or injuries; shortages in materials, equipment, or qualified labor; changes to the scope or timing of the projects; general contractors, subcontractors, or equipment not performing as required under their contracts; the inability to agree to contract terms or disputes in contract terms; the inability to successfully resolve warranty claims; poor initial cost estimates; work stoppages; adverse weather conditions; government actions; legal action; unforeseen engineering or technology issues; limited access to capital or other financing arrangements; and other adverse economic conditions. We may not be able to recover all costs for the projects in rates and face increased risk of potential impairment of our project investment if a construction project is not completed or is delayed, or final costs exceed expectations or the costs approved by our regulators. We may not be able to meet capacity requirements to comply with electric demand planning reserve margins if a construction project is not completed or is delayed. Inability to recover costs, or inability to complete projects in a timely manner, could adversely impact our financial condition and results of operations. Supply chain disruptions could negatively impact our operations and implementation of our strategy - Our operations and strategy depend on the global supply chain to procure the equipment, materials and other resources necessary to provide services in a safe and reliable manner and construct new utility infrastructure. The global supply chain has experienced, and is expected to continue to experience, disruptions due to a multitude of factors, such as geopolitical issues, supplier manufacturing constraints, labor issues, transportation issues, resource availability, long lead times, tariffs, tighter credit markets, inflation, the COVID-19 pandemic and weather. These disruptions have impacted, and are expected to continue to impact, our ability to receive critical materials, supplies and services in a timely and economic manner. This could have an adverse impact by increasing costs and delaying the construction, maintenance or repair of items that are needed to support normal operations or are necessary to our construction projects to implement our strategy. Inability to recover higher costs, or inability to complete projects in a timely manner, could adversely impact our financial condition and results of operations. Our utility business is seasonal and may be adversely affected by the impacts of weather - Electric and gas utility businesses are seasonal businesses. Demand for electricity is greater in the summer months associated with higher air conditioning needs and winter months associated with higher heating needs. Demand for natural gas depends significantly upon temperature patterns in winter months due to heavy use in residential and commercial heating. As a result, our overall operating results in the future may fluctuate substantially on a seasonal basis. In addition, we have historically generated less revenues and income when temperatures are warmer in the winter and/or cooler in the summer. Thus, mild winters and/or summers could have an adverse impact on our financial condition and results of operations. We face risks associated with operating electric and natural gas infrastructure - The operation of electric generation and distribution infrastructure involves many risks, including start-up risks, breakdown or failure of equipment, fires developing from our power lines, transformers or substations, dam failure at one of our hydroelectric facilities, the dependence on a specific fuel source, including the supply and transportation of fuel, the risk of performance below expected or contracted levels of output or efficiency, public and employee safety, operator error and ruptured oil and chemical tanks. The operation of our natural gas distribution and transportation infrastructure also involves many risks, such as leaks, explosions, mechanical problems, members of the public and contractors coming into contact with our infrastructure, and employee and public safety. In addition, the North American electric transmission grid is highly interconnected and, in extraordinary circumstances, disruptions at particular points within the grid could cause an extensive power outage in our service territories. Increased utilization of customer- and third party-owned generation technologies could also disrupt the reliability and balance of the electricity grid. Further, the electric transmission system in our utilities service territories can experience constraints, limiting the ability to transmit electricity within our service territories. The transmission constraints could result in an inability to deliver ##TABLE_START 16 ##TABLE_ENDTable of Co ntents electricity from generating facilities, particularly wind generating facilities, to the national grid, or to access lower cost sources of electricity. These risks could cause significant harm to employees, customers and the public, including loss of human life, significant damage to property, adverse impacts on the environment and impairment of our operations, all of which could result in substantial financial losses to us. We are also responsible for compliance with new and changing regulatory standards involving safety, reliability and environmental compliance, including regulations under the Pipeline and Hazardous Materials Safety Administration, the Occupational Health and Safety Administration, the North American Electric Reliability Corporation and Transportation Security Administration. Failure to meet these regulatory standards could result in substantial fines. Lastly, we have obligations to provide electric and natural gas service to customers under regulatory requirements and contractual commitments. Failure to meet our service obligations could adversely impact our financial condition and results of operations. Storms or other natural disasters may impact our operations in unpredictable ways - Storms and other natural disasters, including events such as floods, tornadoes, windstorms like the 2020 derecho in Iowa, blizzards, ice storms, extreme hot temperatures, extreme cold temperatures, fires, solar flares or pandemics may adversely impact our ability to generate, purchase or distribute electric energy and gas or obtain fuel or other critical supplies. In addition, we could incur large costs to repair damage to our generating facilities and electric and gas infrastructure, or costs related to environmental remediation, due to storms or other natural disasters. The restoration costs may not be fully covered by insurance policies and may not be fully recovered in rates, or recovery in rates may be delayed. Storms and natural disasters may impact our customers and the resulting reduced demand for energy could cause lower sales and revenues, which may not be replaced or recovered in rates, or rate recovery may be delayed. Any of these items could adversely impact our financial condition and results of operations. Threats of terrorism and catastrophic events that could result from terrorism may impact our operations in unpredictable ways - We are subject to direct and indirect effects of terrorist threats and activities. Generation, transmission and distribution facilities, in general, have been identified as potential targets of physical or cyber attacks. Physical attacks on transmission and distribution facilities that appeared to be terrorist-style attacks have occurred. Our gas distribution system could also be the target of terrorist threats and activities. The risks posed by such attacks could include, among other things, the inability to generate, purchase or distribute electric energy or obtain fuel sources, the increased cost of security and insurance, the disruption of, volatility in, or other effects on capital markets, and a decline in the economy and/or energy usage within our service territories, all of which could adversely impact our financial condition and results of operations. In addition, the cost of repairing damage to our facilities and infrastructure caused by acts of terrorism, and the loss of revenue if such events prevent us from providing utility service to our customers, could adversely impact our financial condition and results of operations. We may not be able to fully recover costs related to commodity prices - We have natural gas and coal supply and transportation contracts in place for some of the natural gas and coal we require to generate electricity. We also have transportation and supply agreements in place to facilitate delivery of natural gas to our customers. Our counterparties to these contracts may not fulfill their obligations to provide natural gas or coal to us due to financial or operational problems caused by natural disasters, severe weather, economic conditions, labor shortages, employee strikes, transportation issues, pandemics, physical attacks or cyber attacks. If we were unable to obtain enough natural gas or coal for our electric generating facilities under our existing contracts, or to obtain electricity under existing or future purchased power agreements, we could be required to purchase natural gas or coal at higher prices, forced to purchase electricity from higher-cost generating resources in the Midcontinent Independent System Operator, Inc. (MISO) energy market and/or required to purchase replacement capacity to comply with electric demand planning reserve margins. We may be obligated to pay for coal deliveries under our contracts even if our coal-fired generating facilities do not operate enough to fully utilize the amounts of coal covered by the contracts. If, for natural gas delivery to our customers, we were unable to obtain our natural gas supply requirements under existing or future natural gas supply and transportation contracts, we could be required to purchase natural gas at higher prices from other sources. Natural gas market prices have been volatile in the past and could be volatile in the future due to additional future regulations, increased demand including due to increased liquified natural gas demand from foreign countries, limited global suppliers of natural gas, periods of extremely cold temperatures or disruption in supply caused by major storms or pipeline explosions. We may not be able to pass on all of the changes in costs to our customers, especially at WPL where we do not have an automatic retail electric fuel cost adjustment clause to timely recover such costs and where electric fuel cost recovery may be limited if WPL earns in excess of its authorized return on common equity. Increases in prices and costs due to disruptions that are not recovered in rates fully, in a timely manner, may adversely impact our financial condition and results of operations. Energy industry changes could have a negative effect on our businesses - We operate in a highly regulated business environment. The advent of new and unregulated markets has the potential to significantly impact our financial condition and results of operations. Further, competitors may not be subject to the same operating, regulatory and financial requirements that we are, potentially causing a substantial competitive disadvantage for us. Changes in public policy, such as new tax incentives that we cannot take advantage of or efforts to deregulate the utility industry, could provide an advantage to competitors. Changes in technology could also alter the channels through which electric customers produce, store, buy or utilize power, which could reduce the revenues or increase the expenses of our utility companies. Increased competition in our primary retail electric service territories may have an adverse impact on our financial condition and results of operations. ##TABLE_START 17 ##TABLE_ENDTable of Co ntents We face risks related to non-utility operations - We rely on our non-utility operations for a portion of our earnings. If our non-utility holdings do not perform at expected levels, we could experience an adverse impact on our financial condition and results of operations. Risks Related to Laws and Regulations Our utility business is significantly impacted by government legislation, regulation and oversight - Our utility financial condition is influenced by how regulatory authorities, including the IUB, the PSCW and FERC, establish the rates we can charge our customers, our authorized rates of return and common equity levels, and the costs that may be recovered from customers. Our ability to timely obtain rate adjustments to earn authorized rates of return depends upon timely regulatory action under applicable statutes and regulations, and cannot be guaranteed. In future rate reviews, IPL and WPL may not receive an adequate amount of rate relief to recover all costs and earn their authorized rates of return, rates may be reduced, rate refunds may be required, rate adjustments may not be approved on a timely basis, costs may not be otherwise recovered through rates, future rates may be temporarily frozen, certain rate base items may not receive a full weighted average cost of capital, and authorized rates of return on capital may be reduced. As a result, we may experience adverse impacts on our financial condition and results of operations. In addition, our operations are subject to extensive regulation primarily by the IUB, the PSCW and FERC. We are also subject to oversight and monitoring by organizations such as the North American Electric Reliability Corporation, the Midwest Reliability Organization, the Pipeline and Hazardous Materials Safety Administration, MISO and the Transportation Security Administration. The impacts on our operations include: our ability to site and construct new generating facilities, such as renewable energy projects, and recover associated costs, including our ability to continue to use a renewable energy rider in Iowa; our ability to decommission generating facilities and recover related costs and the remaining carrying value of these facilities and related assets; changes to MISOs resource adequacy process establishing seasonal capacity planning reserve margin and capacity accreditation requirements that may impact how and when new generating facilities such as IPLs and WPLs additional solar generation may be accredited with energy capacity, and may require IPL and WPL to adjust their current resource plans, to add resources to meet the requirements of MISOs new process, or procure capacity in the market whereby such costs might not be recovered in rates; the impact of the lack of availability of existing and new generating facilities has on our accredited capacity for such facilities pursuant to MISOs new seasonal resource adequacy process; the rates paid to transmission operators and how those costs are recovered from customers, including our ability to continue to use a transmission rider in Iowa; our ability to site, construct and recover costs for new natural gas pipelines; our ability to recover costs to upgrade our electric and gas distribution systems; the amount of certain sources of energy we must use, such as renewable sources; our ability to purchase generating facilities and recover the costs associated therewith; our ability to sell utility assets and any conditions placed upon the sale of such assets; our ability to enter into purchased power agreements and recover the costs associated therewith; the allocation of expenditures by transmission companies on transmission network upgrades and our ability to recover costs associated therewith; reliability; safety; the issuance of securities and ability to use other financing arrangements for our renewable energy projects; accounting matters; and transactions between affiliates. These regulatory authorities and organizations are also empowered to impose financial penalties and other sanctions, including requirements to implement new compliance programs. Failure to obtain approvals for any of these matters in a timely manner, or receipt of approvals with uneconomical conditions, may cause us not to pursue the construction of such projects or to record an impairment of our assets and may have a material adverse impact on our financial condition and results of operations. Our regulators or legislatures could change regulations or laws to permit third parties to provide renewable energy directly to our customers without being treated as a utility, potentially causing a competitive disadvantage for us. Changes to these regulations could materially increase our costs or cause us to reconsider our strategy, which could have a material adverse impact on our financial condition and results of operations. Provisions of the Wisconsin

Utility Holding Company Act may limit our ability to invest in or grow our non-utility activities and may deter potential purchasers who might be willing to pay a premium for our stock. Changes to certain tax elections, tax regulations and future taxable income could negatively impact our financial condition and results of operations - We have significantly reduced our federal and state income tax obligations through tax planning strategies and the utilization of bonus depreciation deductions for certain expenditures for property. These tax planning strategies and bonus depreciation deductions have generated large tax credit carryforwards. We plan to utilize all of these tax credit carryforwards in the future to reduce our income tax obligations. If we cannot generate enough taxable income in the future to utilize all of the tax credit carryforwards before they expire due to lower than expected financial performance or changes to tax regulations, we may incur material charges to earnings. The Inflation Reduction Act of 2022 allows for the sale or transfer of renewable tax credits to other taxpayers. We plan to sell a substantial amount of our eligible renewable tax credits in future years. This is a new market that will require regulations and guidance from taxing authorities. It is unclear what terms and pricing the sale of renewable tax credits will require. If we are unable to sell renewable tax credits at reasonable terms, that could materially impact our tax credit carryforward position. In addition, our tax liability is determined by our taxable income multiplied by the current tax rates in effect. If the tax rates are increased, we may experience adverse impacts to our financial condition and results of operations. Our utility business currently operates wind and solar generating facilities, which generate production tax credits for us to use to reduce our federal tax obligations. The amount of production tax credits we earn is dependent on the date the qualifying generating facilities are placed in service, the level of electricity output generated by our qualifying generating facilities and ##TABLE_START 18 ##TABLE_ENDTable of Co ntents sold to an unrelated buyer, and the applicable tax credit rate. If there is a disagreement on the in-service date, the amount of production tax credits that we can generate may be significantly reduced. A variety of operating and economic parameters, including transmission constraints, the imbalance of supply and demand of energy resulting in unfavorable pricing for wind or solar energy, adverse weather conditions and breakdown or failure of equipment, could significantly reduce the production tax credits generated by our wind or solar facilities resulting in a material adverse impact on our financial condition and results of operations. Our strategic plan includes developing storage facilities, which are expected to generate investment tax credits. Investment tax credits are dependent on the date the qualifying generating facilities begin and end construction and the costs of the qualifying generating facilities. If there is a disagreement on the dates construction began and ended or the qualifying costs, the amount of investment tax credits awarded may be significantly reduced, possibly adversely impacting our financial condition and results of operations. The Inflation Reduction Act of 2022 introduced new labor requirements that are required to qualify for the full value of renewable tax credits. Failure to meet these requirements on future renewable projects could result in a significant reduction in the amount of renewable tax credits, which could adversely impact our financial condition and results of operations. Our utility businesses are subject to numerous environmental laws and regulations - Our utilities are subject to numerous federal, regional, state and local environmental laws, regulations, court orders, and international treaties. These laws, regulations and court orders generally concern emissions into the air, discharges into water, use of water, wetlands preservation, remediation of contamination, waste disposal and containment, disposal of coal combustion residuals, hazardous waste disposal, threatened and endangered species, and noise regulation, among others. Failure to comply with such laws, regulations and court orders, or to obtain or comply with any necessary environmental permits pursuant to such laws and regulations, could result in injunctions, fines or other sanctions. Environmental laws and regulations affecting power generation and electric and gas distribution are complex and subject to continued uncertainty and could be changed by the current Presidential Administration. These laws and regulations have imposed, and proposed laws and regulations could impose in the future, additional costs on our utility operations. We have incurred, and will continue to incur, capital and other expenditures to comply with these and other environmental laws and regulations. Changes in or new development of environmental restrictions may force us to incur significant expenses or expenses that may exceed our estimates. There can be no assurance that we would be able to recover all or any increased environmental costs from our customers. Failure to comply with the laws, regulations and court orders, changes in the laws and regulations and failure to recover costs of compliance may adversely impact our financial condition and results of operations. Actions related to global climate change and reducing greenhouse gas (GHG) emissions could negatively impact us - Regulators, customers and investors continue to raise concerns about climate change and GHG emissions. National regulatory action and international regulatory actions continue to evolve. We are focused on executing a long-term strategy to deliver safe, reliable and affordable energy with lower carbon dioxide (CO2) emissions independent of changing policies and political landscape. However, it is unclear how these climate change concerns will ultimately impact us. We could incur costs or other obligations to comply with future GHG regulations, and could become the target of legal claims or challenges, because generating electricity using fossil fuels emits CO2 and other GHGs. Further, investors may determine that we are too reliant on fossil fuels, reducing demand for our stock, which may cause our stock price to decrease, or not buy our debt securities, which may cause our cost of capital to increase. We could face additional pressures from customers, investors or other stakeholders to more rapidly reduce CO2 emissions on a voluntary-basis, including faster adoption of lower CO2 emitting technologies and management of excess renewable energy credits. The timing and pace to fully achieve decarbonization is also contingent on the future development of technologies to reliably store and manage electricity, as well as electrification of other economic sectors. The EPAs approach and timing for implementing rules to regulate CO2 emissions at fossil-fuel fired electric generating units remains undecided and subject to litigation and could change in the current Presidential Administration. Various legislative and regulatory proposals to address climate change at the national, state and local levels continue to be introduced. Potential future requirements to reduce CO2, methane and other GHGs from the energy and manufacturing sectors could affect our operations in various ways. Regulation or legislation mandating CO2 emissions reductions or other clean energy standards affecting utility companies could materially increase costs, causing some electric generating units to be uneconomical to operate or maintain. We are vulnerable to potential risks associated with transition to a lower-carbon economy that may extend to our supply chain and natural gas operations. Regulation of oil and gas production could affect our upstream supply of natural gas for electricity generation and to provide directly to our residential and business customers from our local distribution company. This could result in rapid increased demand for alternative non-fossil energy sources and economy-wide electrification. Changes to regional and local climate trends such as the frequency, seasonality, and severity of weather conditions could directly and indirectly impact our company. Acute and chronic physical risks could disrupt our operations or affect our property. Furthermore, it could affect the timing of peak demand and overall energy consumption of our customers. We cannot provide any assurance regarding the potential impacts of climate change or related policies and regulations to reduce GHG emissions on our operations and these could have a material adverse impact on our financial condition and results of operations. Risks Related to Economic, Financial and Labor Market Conditions We are subject to employee workforce factors that could affect our businesses - We operate in an industry that requires specialized technical skills. Further, we must build a workforce that is innovative, customer-focused and competitive to thrive ##TABLE_START 19 ##TABLE_ENDTable of Co ntents in the future in order to successfully implement our strategy. We have seen an increase in retirements due to our aging workforce and the recent impact of rising interest rates on pension plan benefits. The labor market for our employees is very competitive, increasing the likelihood that we may lose critical employees or have difficulty hiring qualified employees for critical roles. Critical employees are being hired at a higher cost. It may be difficult to hire and retain such a skilled workforce due to labor market conditions, such as low unemployment rates in our service territories, the length of time employees need to acquire the skills, and general competition for talent. The competitive employment market also increases the amounts we pay our employees in critical positions. We are also subject to collective bargaining agreements covering approximately 1,700 employees. Any work stoppage experienced in connection with negotiations of collective bargaining agreements could adversely affect our financial condition and results of operations as well as our ability to implement our strategy. We are subject to limitations on our ability to pay dividends - Alliant Energy is a holding company with no significant operations of its own. The primary sources of funds for Alliant Energy to pay dividends to its shareowners are dividends and distributions from its subsidiaries, primarily its utility subsidiaries. Our subsidiaries are separate and distinct legal entities and have no obligation to pay any amounts to Alliant Energy, whether by dividends, distributions, loans or other payments. The ability of our subsidiaries to pay dividends or make distributions to Alliant Energy and, accordingly, our ability to pay dividends on Alliant Energy common stock will depend on regulatory limitations, earnings, cash flows, capital requirements and general financial condition of our subsidiaries. Our utilities have dividend payment restrictions based on the terms of regulatory limitations applicable to them. If we do not receive adequate dividends and distributions from our subsidiaries, then we may not be able to make, or may have to reduce, dividend payments on Alliant Energy common stock. We are subject to risks related to inflation - We have recently experienced a significant increase in inflation. The impact of supply chain disruptions, COVID-19 and other factors continue to create uncertainty in near-term economic conditions, including whether inflation will continue and at what rate. Increases in inflation raise our costs for labor, materials and services. Inflation may also cause interest rates to increase, increasing our cost of capital. Failure to timely recover these increased costs in rates may adversely impact our financial condition and results of operations. Further, increased costs due to inflation will directly and indirectly increase customer costs, which may decrease demand for energy and adversely impact our financial condition and results of operations. We may incur material post-closing adjustments related to past asset and business divestitures - We have sold certain non-utility subsidiaries such as Whiting Petroleum Corporation (Whiting Petroleum). We may continue to incur liabilities relating to our previous ownership of, or the transactions pursuant to which we disposed of, these subsidiaries and assets. Any potential liability depends on a number of factors outside of our control, including the financial condition of Whiting Petroleum, certain of its partners, and/or their assignees. Any required payments on retained liabilities, guarantees or indemnification obligations with respect to Whiting Petroleum or other past and future asset or business divestitures could adversely impact our financial condition and results of operations. We are dependent on the capital markets and could be negatively impacted by disruptions in the capital markets - Successful implementation of our strategy is dependent upon our ability to access the capital markets. We have forecasted capital expenditures of approximately $8 billion over the next four years. Disruption, uncertainty or volatility in the capital markets could increase our cost of capital or limit our ability to raise funds needed to operate our businesses. Disruptions could be caused by Federal Reserve policies and actions, currency concerns, inflation, economic downturn or uncertainty, monetary policies, a negative view of the utility industry or our company, failures of financial institutions, U.S. debt management concerns, U.S. debt limit and budget debates, including government shutdowns, European and worldwide sovereign debt concerns, other global or geopolitical events, or other factors. Increases in interest rates will cause the cost of capital to increase and may cause the price of our equity securities to decline. Any disruptions in capital markets could adversely impact our ability to implement our strategy. We rely on our strong credit ratings to access the credit markets. If our credit ratings are downgraded for any reason, such as worsening credit metric impacts, negative changes to our regulatory environment, or general negative outlook for the utility industry, we could pay higher interest rates in future financings, the pool of potential lenders could be reduced, borrowing costs under existing credit facilities could increase, our access to the commercial paper market could be limited, or we could be required to provide additional credit assurance, including cash collateral, to contract counterparties. If our access to capital were to become significantly constrained or costs of capital increased significantly due to lowered credit ratings, prevailing industry conditions, regulatory constraints, volatility of the capital markets, inflation or other factors, our financial condition and results of operations could be adversely affected. Our pension and other postretirement benefits plans are subject to investment and interest rate risk that could negatively impact our financial condition - We have pension and other postretirement benefits plans that provide benefits to many of our employees and retirees. Costs of providing benefits and related funding requirements of these plans are subject to changes in the liabilities of the plans and market value of the assets that fund the plans. The funded status of the plans and the related costs reflected in our financial statements are affected by various factors, which are subject to an inherent degree of uncertainty, including economic conditions, financial market performance, interest rates, life expectancies and demographics. Recessions and volatility in the domestic and international financial markets have negatively affected the asset values of our pension plans at various times in the past. Poor investment returns or lower interest rates may necessitate ##TABLE_START 20 ##TABLE_ENDTable of Co ntents accelerated funding of the plans to meet minimum federal government requirements, which could have an adverse impact on our financial condition and results of operations.

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ITEM 1. BUSINESS GENERAL Ameren, formed in 1997 and headquartered in St. Louis, Missouri, is a public utility holding company whose primary assets are its equity interests in its subsidiaries. Amerens subsidiaries are separate, independent legal entities with separate businesses, assets, and liabilities. Dividends on Amerens common stock and the payment of expenses by Ameren depend on distributions made to it by its subsidiaries. Table of Contents Below is a summary description of Amerens principal subsidiaries Ameren Missouri, Ameren Illinois, and ATXI. Ameren also has other subsidiaries that conduct other activities, such as providing shared services. A more detailed description can be found in Note 1 Summary of Significant Accounting Policies under Part II, Item 8, of this report. Ameren Missouri operates a rate-regulated electric generation, transmission, and distribution business and a rate-regulated natural gas distribution business in Missouri. Ameren Illinois operates rate-regulated electric transmission, electric distribution, and natural gas distribution businesses in Illinois. ATXI operates a FERC rate-regulated electric transmission business in the MISO. For additional information about the development of our businesses, our business operations, and factors affecting our results of operations, financial position, and liquidity, see Managements Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7, and Note 1 Summary of Significant Accounting Policies and Note 2 Rate and Regulatory Matters under Part II, Item 8, of this report. BUSINESS SEGMENTS Ameren has four segments: Ameren Missouri, Ameren Illinois Electric Distribution, Ameren Illinois Natural Gas, and Ameren Transmission. The Ameren Missouri segment includes all of the operations of Ameren Missouri. Ameren Illinois Electric Distribution consists of the electric distribution business of Ameren Illinois. Ameren Illinois Natural Gas consists of the natural gas business of Ameren Illinois. Ameren Transmission primarily consists of the aggregated electric transmission businesses of Ameren Illinois and ATXI. Ameren Missouri has one segment. Ameren Illinois has three segments: Ameren Illinois Electric Distribution, Ameren Illinois Natural Gas, and Ameren Illinois Transmission. An illustration of the Ameren Companies reporting structures is provided below: (a) The Ameren Transmission segment also includes allocated Ameren (parent) interest charges, as well as other subsidiaries engaged in electric transmission project development and investment. RATES AND REGULATION Rates The rates that Ameren Missouri, Ameren Illinois, and ATXI are allowed to charge for their utility services significantly influence the results of operations, financial position, and liquidity of these companies and Ameren. The electric and natural gas utility industry is highly regulated. The utility rates charged to customers are determined by governmental entities, including the MoPSC, the ICC, and the FERC. Table of Contents Decisions by these entities are influenced by many factors, including the cost of providing service, the prudency of expenditures, the quality of service, regulatory staff knowledge and experience, customer intervention, and economic conditions, as well as social and political views. Decisions made by these governmental entities regarding customer rates are largely outside of our control. These decisions, as well as the regulatory lag involved in the process of obtaining approval for new customer rates, could have a material adverse effect on the results of operations, financial position, and liquidity of the Ameren Companies. The extent of the regulatory lag varies for each of Amerens electric and natural gas jurisdictions, with the Ameren Transmission and Ameren Illinois Electric Distribution businesses experiencing the least amount of regulatory lag. Depending on the jurisdiction, the effects of regulatory lag are mitigated by various means, including annual revenue requirement reconciliations, the decoupling of revenues from sales volumes to ensure revenues approved in a regulatory rate review are not affected by changes in sales volumes, the recovery of certain capital investments between traditional regulatory rate reviews, the level and timing of expenditures, the use of future test years to establish customer rates, and the use of trackers and riders. The MoPSC regulates rates and other matters for Ameren Missouri. The ICC regulates rates and other matters for Ameren Illinois. The MoPSC and the ICC regulate non-rate utility matters for ATXI. ATXI does not have retail distribution customers; therefore, the MoPSC and the ICC do not have authority to regulate ATXIs rates. The FERC regulates Ameren Missouris, Ameren Illinois, and ATXIs cost-based rates for the wholesale transmission and distribution of energy in interstate commerce and various other matters discussed below under General Regulatory Matters. For additional information on Ameren Missouri, Ameren Illinois, and ATXI rate matters, see Results of Operations and Outlook in Managements Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7, Quantitative and Qualitative Disclosures About Market Risk under Part II, Item 7A, and Note 2 Rate and Regulatory Matters under Part II, Item 8, of this report. The following table summarizes the key terms of the rate orders in effect for customer billings for each of Amerens rate-regulated utilities as of January 1, 2023, except as noted: ##TABLE_START Rate Regulator Effective Rate Order Issued In Allowed ROE Percent of Common Equity Rate Base (in billions) Portion of Amerens 2022 Operating Revenues (a) Ameren Missouri Electric service (b) MoPSC December 2021 (c) (c) (c) $10.2 (d) 48% Natural gas delivery service MoPSC December 2021 (e) (e) (e) $0.3 3% Ameren Illinois Electric distribution delivery service (f) ICC December 2022 7.85% 50.00% $3.9 28% Natural gas delivery service (g) ICC January 2021 9.67% 52.00% $2.1 15% Electric transmission service (h) FERC (h) 10.52% 54.48% $3.4 4% ATXI Electric transmission service (h) FERC (h) 10.52% 60.16% $1.3 2% ##TABLE_END(a) Includes pass-through costs recovered from customers, such as purchased power for electric distribution delivery service and natural gas purchased for resale for natural gas delivery service, and intercompany eliminations. (b) Ameren Missouris electric generation, transmission, and delivery service rates are bundled together and charged to retail customers under a combined electric service rate. Because the bundled rates charged to MoPSC retail customers include the revenue requirement associated with Ameren Missouri's FERC-regulated transmission services, the table above does not separately reflect a FERC-authorized rate base or allowed ROE. (c) This rate order did not specify an ROE, but specified that Ameren Missouris September 30, 2021 capital structure, which was composed of 51.97% common equity, is to be used in the PISA and RESRAM. As a result of this order, new rates became effective in February 2022. (d) Excludes PISA and RESRAM deferrals for investments after September 30, 2021. Deferrals after September 30, 2021, through December 31, 2022, will be included in Ameren Missouris requested rate base in the 2022 electric service regulatory rate review. (e) This rate order did not specify an ROE or a capital structure. As a result of this order, new rates became effective in February 2022. (f) Ameren Illinois electric distribution delivery service rates are updated annually and become effective each January. This rate order was based on 2021 actual costs, expected net plant additions for 2022, and the annual average of the monthly yields during 2021 of the 30-year United States Treasury bonds plus 580 basis points, which was 2.05%. Ameren Illinois 2023 electric distribution delivery service revenues will be based on its 2023 actual recoverable costs, rate base, common equity percentage, and an allowed ROE, as calculated under the IEIMAs performance-based formula ratemaking framework. (g) This rate order was based on a 2021 future test year, and new rates became effective in January 2021. (h) Transmission rates are updated annually and become effective each January. They are determined by a company-specific, forward-looking formula ratemaking framework based on each years forecasted information. The 10.52% return, which includes a 50 basis points incentive adder for participation in an RTO, is based on the FERCs May 2020 order. For additional information regarding this order and an August 2022 ruling by the United States Court of Appeals for the District of Columbia Circuit related to a review of the May 2020 order, see Note 2 Rate and Regulatory Matters under Part II, Item 8, of this report. General Regulatory Matters Ameren Missouri, Ameren Illinois, and ATXI must receive FERC approval to enter into various transactions, such as issuing short-term debt securities and conducting certain acquisitions, mergers, and consolidations involving electric utility holding companies. In addition, Ameren Missouri, Ameren Illinois, and ATXI must receive authorization from the applicable state public utility regulatory agency to issue stock and long-term debt securities and to conduct mergers, affiliate transactions, and various other activities. Table of Contents Ameren Missouri, Ameren Illinois, and ATXI are also subject to mandatory reliability standards, including cybersecurity standards adopted by the FERC, to ensure the reliability of the bulk electric power system. These standards are developed and enforced by the NERC, pursuant to authority delegated to it by the FERC. Ameren Missouri, Ameren Illinois, and ATXI are members of the SERC. The SERC is one of six regional entities and represents all or portions of 16 central and southeastern states under authority from the NERC for the purpose of implementing and enforcing reliability standards approved by the FERC. Ameren Missouri is also a member of the MRO, which is also one of the six regional entities and represents all or portions of 16 central, southern, and midwestern states, as well as two Canadian provinces, under authority from the NERC. The regional entities of the NERC work to safeguard the reliability of the bulk power systems throughout North America. If any of Ameren Missouri, Ameren Illinois, or ATXI is found not to be in compliance with these mandatory reliability standards, it could incur substantial monetary penalties and other sanctions. Under the Public Utility Holding Company Act of 2005, the FERC and the state public utility regulatory agencies in each state Ameren and its subsidiaries operate in may access books and records of Ameren and its subsidiaries that are found to be relevant to costs incurred by Amerens rate-regulated subsidiaries that may affect jurisdictional rates. The act also permits the MoPSC and the ICC to request that the FERC review cost allocations by Ameren Services to other Ameren subsidiaries. Operation of Ameren Missouris Callaway Energy Center is subject to regulation by the NRC. The license for the Callaway Energy Center expires in 2044. Ameren Missouris hydroelectric Osage Energy Center and pumped-storage hydroelectric Taum Sauk Energy Center, as licensed projects under the Federal Power Act, are subject to FERC regulations affecting, among other aspects, the general operation and maintenance of the projects. The licenses for the Osage Energy Center and the Taum Sauk Energy Center expire in 2047 and 2044, respectively. Ameren Missouris Keokuk Energy Center and its dam on the Mississippi River between Hamilton, Illinois, and Keokuk, Iowa, are operated under authority granted by an Act of Congress in 1905. For additional information on regulatory matters, see Note 2 Rate and Regulatory Matters, Note 9 Callaway Energy Center, and Note 14 Commitments and Contingencies under Part II, Item 8, of this report. Environmental Matters Our electric generation, transmission, and distribution and natural gas distribution and storage operations must comply with a variety of statutes and regulations relating to the protection of the environment and human health and safety. These environmental statutes and regulations are comprehensive and include the storage, handling, and disposal of waste materials and hazardous substances, emergency planning and response requirements, limitations and standards applicable to discharges from our facilities into the air or water that are enforced through permitting requirements, and wildlife protection laws, including those related to endangered species. Federal and state authorities continually revise these regulations and adopt new regulations, which may impact our planning process and the ultimate implementation of these or other new or revised regulations. For discussion of environmental matters, including NO x and SO 2 emission reduction requirements, regulation of CO 2 emissions, wastewater discharge standards, remediation efforts, CCR management regulations, and a discussion of litigation against Ameren Missouri with respect to NSR, the Clean Air Act, and Missouri law in connection with projects at Ameren Missouris Rush Island Energy Center, see Note 14 Commitments and Contingencies under Part II, Item 8, of this report. TRANSMISSION Ameren owns an integrated transmission system that is composed of the transmission assets of Ameren Missouri, Ameren Illinois, and ATXI. Ameren also operates two MISO balancing authority areas: AMMO and AMIL. The AMMO balancing authority area includes the load and most energy centers of Ameren Missouri, and had a peak demand of 7,584 MWs in 2022. The AMIL balancing authority area includes the load of Ameren Illinois and certain natural gas-fired energy centers of Ameren Missouri, and had a peak demand of 8,510 MWs in 2022. The Ameren transmission system directly connects with 15 other balancing authority areas for the exchange of electric energy. Ameren Missouri, Ameren Illinois, and ATXI are transmission-owning members of the MISO. Ameren Missouri is authorized by the MoPSC to participate in the MISO for an indefinite term, subject to the MoPSCs authority to require future proceedings if an event or circumstance occurs that significantly affects Ameren Missouris position in the MISO. Ameren Illinois election to participate in the MISO is subject to the ICCs oversight. In July 2022, the ICC issued an order requiring Ameren Illinois to perform a cost-benefit study of continued participation in the MISO compared to participation in PJM Interconnection LLC, another RTO, and file the study by July 2023. For additional information regarding the July 2022 ICC order, see Note 2 Rate and Regulatory Matters under Part II, Item 8, of this report. Table of Contents SUPPLY OF ELECTRIC POWER Capacity Ameren Missouri sells nearly all of its capacity to the MISO and purchases the capacity it needs to supply its native load sales from the MISO. In the April 2022 MISO capacity auction, Ameren Missouris generation resources exceeded its native load capacity requirements. Ameren Illinois purchases capacity from the MISO and through bilateral contracts resulting from IPA procurement events. In August 2022, the FERC issued an order approving changes to the annual MISO capacity auction. Historically, the auctions were designed to cover annual peak demand plus a target reserve margin.

Beginning with the April 2023 auction for the June 2023 to May 2024 planning year, auctions will include four seasonal load forecasts and available capacity levels and will be designed to cover each seasons peak demand plus a target reserve margin. The seasonal auction structure will help to address variability in resources as the MISO begins to rely more heavily on renewable generation. Ameren Missouri Ameren Missouris electric supply is primarily generated from its energy centers. Factors that could cause Ameren Missouri to purchase power include, among other things, energy center outages, the fulfillment of renewable energy requirements, extreme weather conditions, the availability of power at a cost lower than its generation cost, and the lack of sufficient owned generation availability. Ameren Missouri files a long-term nonbinding integrated resource plan with the MoPSC every three years. The most recent integrated resource plan was filed in September 2020 and changed in June 2022 to include certain modifications to Ameren Missouris preferred approach for meeting customers projected long-term energy needs in a cost-effective manner while maintaining system reliability and customer affordability. The preferred approach includes, among other things, the following: the continued implementation of customer energy-efficiency programs; expanding renewable sources by adding 2,800 MWs of renewable generation by 2030 and a total of 4,700 MWs of renewable generation by 2040, representing investment opportunities of $7.5 billion, inclusive of the 350 MWs of solar generation projects discussed in Note 2 Rates and Regulatory Matters under Part II, Item 8, of this report; adding 800 MWs of battery storage by 2040, representing investment opportunities of $650 million; adding 1,200 MWs of natural gas-fired combined cycle generation by 2031, representing an investment opportunity of $1.7 billion, with plans to switch to hydrogen fuel and/or blend hydrogen fuel with natural gas and install carbon capture technology if these technologies become commercially available at a reasonable cost; adding 1,200 MWs of additional clean dispatchable generation by 2043; the expectation that Ameren Missouri will seek and receive NRC approval for an extension of the operating license for the Callaway Energy Center beyond its current 2044 expiration date; extending the retirement date of the coal-fired Sioux Energy Center from 2028 to 2030 to ensure reliability during the transition to clean energy generation, which is subject to the approval of a change in the assets depreciable life by the MoPSC in Ameren Missouris 2022 electric service regulatory rate review; accelerating the retirement date of the Rush Island coal-fired energy center to 2025; retiring the remaining coal-fired energy centers as they reach the end of their useful lives; accelerating the retirement date of the Venice natural gas-fired energy center to 2029; and retiring Ameren Missouris other natural gas-fired energy centers in Illinois by 2040. The addition of renewable and natural gas-fired combined cycle generation facilities is subject to obtaining necessary project approvals, including FERC approval and the issuance of a certificate of convenience and necessity by the MoPSC, as applicable. Ameren Missouri would be adversely affected if the MoPSC does not allow recovery of the remaining investment and decommissioning costs associated with the retirement of an energy center, as well as the ability to earn a return on that remaining investment and those decommissioning costs. In connection with the planned accelerated retirement of the Rush Island Energy Center, Ameren Missouri expects to seek approval from the MoPSC to finance the costs associated with the retirement, including the remaining unrecovered net plant balance associated with the facility, through the issuance of securitized utility tariff bonds pursuant to the Missouri securitization statute. The next integrated resource plan is expected to be filed in September 2023. Ameren Missouri continues to evaluate its longer-term needs for new generating capacity. The need for investment in new sources of energy is dependent on several key factors, including continuation of and customer participation in energy-efficiency programs, the amount of distributed generation from customers, load growth, technological advancements, costs of generation alternatives, environmental regulation of coal-fired and natural gas-fired power plants, and state renewable energy requirements, which could lead to the retirement of current baseload assets before the end of their current useful lives or alterations in the way those assets operate, which could result in increased capital expenditures and/or increased operations and maintenance expenses. Because of the significant time required to plan, acquire permits for, and build a baseload energy center, Ameren Missouri continues to study alternatives and to take steps to preserve options to meet future demand. Steps include evaluating the potential for further diversification of Ameren Missouris generation portfolio through Table of Contents renewable energy generation, including wind and solar generation, natural gas-fired combined cycle generation, including the potential to switch to hydrogen fuel and/or blend hydrogen fuel with natural gas and install carbon capture technology, extending the operating license for the Callaway Energy Center, additional customer energy-efficiency and demand response programs, distributed energy resources, and energy storage. Missouri law requires Ameren Missouri to offer solar rebates and net metering to certain customers that install renewable generation at their premises. The difference between the cost of the rebates and the amount set in base rates are deferred as a regulatory asset or liability under the RESRAM, and earn carrying costs at short-term interest rates. Customers that elect to enroll in net metering are allowed to net their generation against their usage within each billing month. Ameren Illinois In Illinois, while electric transmission and distribution service rates are regulated, power supply prices are not. Although electric customers are allowed to purchase power from an alternative retail electric supplier, Ameren Illinois is required to be the provider of last resort for its electric distribution customers. In 2022, 2021, and 2020, Ameren Illinois procured power on behalf of its customers for 28%, 23%, and 23%, respectively, of its total kilowatthour sales. Power purchased by Ameren Illinois for its electric distribution customers who do not elect to purchase their power from an alternative retail electric supplier comes either through procurement processes conducted by the IPA or through markets operated by the MISO. The IPA administers an RFP process through which Ameren Illinois procures its expected supply. The purchased power and related procurement costs incurred by Ameren Illinois are passed directly to its electric distribution customers through a cost recovery mechanism. Transmission costs are charged to customers who purchase electricity from Ameren Illinois and to alternative retail electric suppliers through a cost recovery mechanism. The purchased power, power procurement, and transmission costs are reflected in Ameren Illinois Electric Distributions results of operations, but do not affect Ameren Illinois Electric Distributions earnings because these costs are offset by corresponding revenues. Ameren Illinois charges distribution service rates to electric distribution customers who purchase electricity, regardless of supplier, which does affect Ameren Illinois Electric Distributions earnings. Pursuant to the IETL, Ameren Illinois is required to file a multi-year integrated grid plan with the ICC every four years. In January 2023, Ameren Illinois filed its first multi-year integrated grid plan for the years 2023 to 2027. The plan outlines how Ameren Illinois expects to operate and invest in electric distribution infrastructure in order to support grid modernization, clean energy, energy efficiency, and the state of Illinois renewable energy, equity, climate, electrification, and environmental goals, while providing safe, secure, reliable, and resilient electric distribution service to customers. Ameren Illinois next multi-year integrated grid plan is required by mid-January 2026. Illinois law requires Ameren Illinois to offer rebates and net metering to certain customers that install renewable generation or paired energy storage systems at their premises. The cost of the rebates are deferred as a regulatory asset, which earn a return at the applicable WACC. Customers that elect to receive a generation rebate and are enrolled in net metering are allowed to net their supply service charges, but not their distribution service charges. Effective January 2023, customers that elect to receive energy storage rebates and have not received generation rebates are allowed to net their supply and distribution service charges. By law, Ameren Illinois electric distribution revenues are decoupled from sales volumes, which ensures that the electric distribution revenues authorized in a regulatory rate review are not affected by changes in sales volumes. POWER GENERATION Ameren Missouri owns energy centers that rely on a diverse fuel portfolio, including coal, nuclear, and natural gas, as well as renewable sources of generation, which include hydroelectric, wind, methane gas, and solar. All of Ameren Missouris coal-fired energy centers were constructed prior to 1978. The Callaway Energy Center began operation in 1984 and is licensed to operate until 2044. As of December 31, 2022, Ameren Missouris coal-fired energy centers represented 9% and 17% of Amerens and Ameren Missouris rate base, respectively. The Meramec Energy Center was retired at the end of its useful life in December 2022. Also in December 2022, Ameren Illinois placed a solar generation facility in service, which is one of two pilot solar projects Ameren Illinois is allowed to invest in under the IETL. See Item 2 Properties under Part I of this report for information regarding our energy centers. Coal Ameren Missouri has an ongoing need for coal as fuel for generation, and pursues a price-hedging strategy consistent with this requirement. Ameren Missouri has agreements in place to purchase and transport coal to its energy centers. While Ameren Missouri has minimum purchase obligations associated with these agreements, the majority of these agreements are not associated with any specific coal-fired energy center. Ameren Missouri burned approximately 14.5 million tons of coal in 2022. For information regarding the percentages of Ameren Missouris projected required supply of coal and coal transportation that are price-hedged through 2027, see Commodity Price Risk under Part II, Item 7A, of this report. About 97% of Ameren Missouris coal is purchased from the Powder River Basin in Wyoming, which has a limited number of suppliers. The remaining coal is typically purchased from the Illinois Basin. Targeted coal inventory levels may be adjusted because of generation levels Table of Contents or uncertainties of supply due to potential work stoppages, delays in coal deliveries, equipment breakdowns, and other factors. Deliveries from the Powder River Basin have occasionally been restricted because of rail congestion, staffing and equipment issues, infrastructure maintenance, derailments, weather, and supplier financial hardship. Coal suppliers in the Powder River Basin are experiencing financial hardship because of a decrease in demand resulting from increased natural gas use and renewable energy generation, and the impact of environmental regulations and concerns related to coal-fired generation. These financial hardships have resulted in bankruptcy filings by certain coal suppliers in recent years. As of December 31, 2022, coal inventories at the Labadie and Sioux energy centers were below targeted levels due to transportation delays in 2022. Delays and disruptions in coal deliveries could cause Ameren Missouri to pursue a strategy that could include reducing off-system sales of power during low-margin periods, buying higher-cost fuels to generate required electricity, and purchasing power from other sources. Nuclear The production of nuclear fuel involves the mining and milling of uranium ore to produce uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride gas, the enrichment of that gas, the conversion of the enriched uranium hexafluoride gas into uranium dioxide fuel pellets, and the fabrication into fuel assemblies. Ameren Missouri has entered into uranium, uranium conversion, uranium enrichment, and fabrication contracts to procure the fuel supply for its Callaway Energy Center. The Callaway Energy Center requires refueling at 18-month intervals. The last refueling was completed in May 2022. The next refueling is scheduled for the fall of 2023. Ameren Missouri has inventories and supply contracts sufficient to meet all of its uranium (concentrate and hexafluoride), conversion, enrichment, and fabrication requirements at least through the 2026 refueling. RENEWABLE ENERGY AND ZERO EMISSION STANDARDS Missouri and Illinois laws require electric utilities to include renewable energy resources in their portfolios. Ameren Missouri and Ameren Illinois satisfied their renewable energy portfolio requirements in 2022. Ameren Missouri In Missouri, utilities are required to purchase or generate electricity equal to at least 15% of native load sales from renewable energy sources, with at least 2% of the requirement derived from solar energy. The requirement is subject to an average 1% annual increase on customer rates over any 10-year period. For renewable generation facilities located in Missouri, 125% of the electricity generated counts towards meeting the requirement. Ameren Missouri expects to satisfy the nonsolar requirement in 2023 with its High Prairie Renewable, Atchison Renewable, Keokuk, and Maryland Heights energy centers, a 102-MW power purchase agreement with a wind farm operator, and immaterial renewable energy credit purchases in the market. The High Prairie Renewable and Atchison Renewable energy centers are wind generation facilities. The Keokuk Energy Center generates electricity using a hydroelectric dam located on the Mississippi River. The Maryland Heights Energy Center generates electricity by burning methane gas collected from a landfill. Ameren Missouri is meeting the solar energy requirement by purchasing solar-generated renewable energy credits from customer-installed systems and by generating energy at its solar facilities. Ameren Illinois In accordance with Illinois law, Ameren Illinois is required to collect funds from all electric distribution customers to fund IPA procurement events for renewable energy credits. The amount set by law and required to be collected from customers by Ameren Illinois is capped at $4.58 per MWh. The IPA establishes its long-term renewable resources procurement plans in a filing made every two years. In July 2022, the ICC approved the IPAs latest long-term renewable resources procurement plan. Based on IPA procurement events that align with the IPAs plan, Ameren Illinois has contractual commitments of approximately 0.7 million wind renewable energy credits per year and approximately 1.7 million solar renewable energy credits per year. Ameren Illinois has also entered into contracts, ending in 2032, to purchase approximately 0.6 million wind renewable energy credits per year. Pursuant to the IETL, if funds collected from customers are not used to procure renewable energy credits, they would be refunded to customers pursuant to a reconciliation proceeding, the first of which is expected to be initiated after August 2023. Based on amounts collected from customers and renewable energy credit purchases under contract, Ameren Illinois does not expect the first reconciliation proceeding to result in refunds to customers. The IPA is expected to file its next long-term renewable resources procurement plan in 2023, which, once approved by the ICC, will establish the 2023 and 2024 renewable energy credit procurement targets. Table of Contents Illinois law also required Ameren Illinois to enter into contracts for zero emission credits in an amount equal to approximately 16% of the actual amount of electricity delivered to retail customers during calendar year 2014, pursuant to Illinois zero emission standard. As a result of a 2018 IPA procurement event, which was approved by the ICC, Ameren Illinois entered into agreements to acquire zero emission credits through May 2027. Annual zero emission credit commitment amounts will be published by the IPA each May prior to the start of the subsequent planning year. Both renewable energy credits and zero emission credits have cost recovery mechanisms, which allow Ameren Illinois to collect from, or refund to, customers differences between actual costs incurred from the resulting contracts and the amounts collected from customers. CUSTOMER ENERGY-EFFICIENCY PROGRAMS Ameren Missouri and Ameren Illinois have implemented energy-efficiency programs to educate their customers and to help them become more efficient energy consumers. These programs provide incentives to customers for installing newer, more efficient technology, and for using energy in a more conservation-minded manner. As a component of the energy-efficiency programs, Ameren Missouri and Ameren Illinois have invested in electric smart meters to provide customers more visibility to their energy consumption and facilitate more efficient use of energy. As of December 31, 2022, smart meters have been installed for 61% of Ameren Missouris electric customers. Ameren Illinois has completed its transition to smart meters, which have been installed for nearly all its electric and natural gas customers. Ameren Missouri In Missouri, the Missouri Energy Efficiency Investment Act established a rider that, among other things, allows electric utilities to recover costs with respect to MoPSC-approved customer energy-efficiency programs. The law requires the MoPSC to ensure that a utilitys financial incentives are aligned to help customers use energy more efficiently, to provide timely cost recovery, and to provide earnings opportunities associated with cost-effective energy-efficiency programs. Missouri does not have a law mandating energy-efficiency programs. In 2018, the MoPSC issued an order approving Ameren Missouris MEEIA 2019 plan. The plan includes a portfolio of customer energy-efficiency and demand response programs through December 2023. Ameren Missouri intends to invest approximately $350 million over the life of the plan, including $75 million in 2023. In addition, the plan includes a performance incentive that provides Ameren Missouri an opportunity to earn additional revenues by achieving certain customer energy-efficiency goals. If the target spending goals are achieved for 2023, additional revenues of $13 million would be recognized in 2023. Through 2022, Ameren Missouri has invested approximately $270 million in MEEIA 2019 customer energy-efficiency programs. Additionally, as part of its Smart Energy Plan, Ameren Missouri has invested $270 million in smart meters since 2019. The MEEIA 2019 plan includes the continued use of the MEEIA rider. The MEEIA rider allows Ameren Missouri to collect from, or refund to, customers any difference between actual program costs, lost electric margins, and any performance incentive and the amounts collected from customers, without a traditional regulatory rate review, subject to MoPSC prudence reviews, until lower volumes resulting from the MEEIA programs are reflected in base rates. Customer rates, based upon both forecasted program costs and lost electric margins and collected via the MEEIA rider, are reconciled annually to actual results. Ameren Illinois State law requires Ameren Illinois to offer customer energy-efficiency programs, and imposes electric energy-efficiency savings goals and a maximum annual amount of investment in electric energy-efficiency programs, which is approximately $120 million annually through 2029 and may increase by up to approximately $30 million from 2026 to 2029 depending on the election of certain customers to participate in the programs. Every four years, Ameren Illinois is required to file a four-year electric energy-efficiency plan with the ICC. In June 2022, the ICC issued an order approving Ameren Illinois electric and natural gas energy-efficiency plans for 2022 through 2025, as well as regulatory recovery mechanisms. The order authorized electric and natural gas energy-efficiency program expenditures of $476 million and $66 million, respectively, over the four-year period. Illinois law allows Ameren Illinois to earn a return on its electric energy-efficiency program investments. Ameren Illinois electric energy-efficiency investments are deferred as a regulatory asset and earn a return at the applicable WACC, with the ROE based on the annual average of the monthly yields of the 30-year United States Treasury bonds plus 580 basis points. The allowed ROE on electric energy-efficiency investments can be increased or decreased by up to 200 basis points, depending on the achievement of annual energy savings goals. While the ICC approves Ameren Illinois four-year electric energy-efficiency plans, the ICC has the ability to reduce the amount of approved electric energy-efficiency savings goals in future plan program years if there are insufficient cost-effective programs available, which could reduce the investments in electric energy-efficiency programs. The electric energy-efficiency program investments and the return on those investments are collected from customers through a rider and are not included in the electric distribution service performance-based formula ratemaking framework. Ameren Illinois natural gas energy-efficiency program costs are recovered through a rider. Table of Contents NATURAL GAS SUPPLY FOR DISTRIBUTION Ameren Missouri and Ameren Illinois are responsible for the purchase and delivery of natural gas to their customers. Ameren Missouri and Ameren Illinois each develop and manage a portfolio of natural gas supply resources. These resources include firm natural gas supply agreements with producers, firm interstate and intrastate transportation capacity, firm no-notice storage capacity leased from interstate pipelines, and on-system storage facilities to maintain natural gas deliveries to customers throughout the year and especially during peak demand periods. Ameren Missouri and Ameren Illinois primarily use Panhandle Eastern Pipe Line Company, Trunkline Gas Company, Natural Gas Pipeline Company of America, Mississippi River Transmission Corporation, Northern Border Pipeline Company, and Texas Eastern Transmission Corporation interstate pipeline systems to transport natural gas to their systems. In addition to transactions requiring physical delivery, certain financial instruments, including those entered into in the New York Mercantile Exchange futures market and in the over-the-counter financial markets, are used to hedge the price paid for natural gas. Natural gas supply costs are passed on to customers of Ameren Missouri and Ameren Illinois under PGA clauses, subject to prudence reviews by the MoPSC and the ICC. For information regarding the percentage of Ameren Missouris and Ameren Illinois projected remaining natural gas supply requirements that are price-hedged through 2027, see Commodity Price Risk under Part II, Item 7A, of this report. For additional information on our fuel, purchased power, and natural gas for distribution supply, see Results of Operations and Liquidity and Capital Resources in Managements Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7, and Commodity Price Risk under Part II, Item 7A, of this report. Also see Note 1 Summary of Significant Accounting Policies, Note 7 Derivative Financial Instruments, Note 13 Related-party Transactions, Note 14 Commitments and Contingencies, and Note 15 Supplemental Information under Part II, Item 8, of this report. HUMAN CAPITAL MANAGEMENT The execution of Amerens core strategy to invest in rate-regulated energy infrastructure, enhance regulatory frameworks and advocate for responsible policies, and optimize operating performance to capitalize on opportunities to benefit our customers, our shareholders, and the environment is driven by the capabilities and engagement of our workforce. Amerens workforce strategy is designed to promote a skilled and diverse workforce that is prepared to deliver on Amerens mission (To Power the Quality of Life) and vision (Leading the Way to a Sustainable Energy Future), both today and in the future. Our workforce strategy is anchored in four key pillars: Culture, Leadership, Talent, and Rewards, which are discussed further below. Foundational to our workforce strategy are our core values of: ##TABLE_START Safety and security Commitment to excellence Respect Accountability Diversity, equity, and inclusion Integrity Teamwork Stewardship ##TABLE_ENDAmerens chief executive officer and chief human resources officer, with the support of other leaders of the Ameren Companies, are responsible for developing and executing our workforce strategy. In addition to reviewing and determining the Ameren Companies compensation practices and policies for the chief executive officer and other executive officers, the Human Resources Committee of Amerens board of directors is responsible for oversight of Amerens human capital management practices and policies, including those related to diversity, equity, and inclusion. The Human Resources Committee and Amerens board of directors are updated regularly on human capital matters. Culture We strive to cultivate a values-based and continuous improvement culture that enables the sustainable execution of our core strategy and reflects the following characteristics: ##TABLE_START We Care about our customers, our communities, and each other We Serve with Passion We Deliver for our customers and stakeholders, today and tomorrow We Win Together as a result of our teamwork and collaboration ##TABLE_ENDWe design our human capital management practices and policies to reinforce our core values, shape our culture, and drive employee engagement. In doing so, we strive to align our employees to our mission and vision, improve safety, enhance innovation, increase productivity, attract and retain top talent, and recognize employee contributions, among other things. We assess employee engagement through a variety of channels. As a part of our assessment, we conduct confidential employee engagement surveys at least annually to identify areas of strength and opportunities for improvement in our employees experience, and take actions aimed at increasing employee engagement. We also capitalized on opportunities presented by the COVID-19 pandemic and implemented work-from-home policies, advanced the digital enablement of our workforce, and enhanced our facilities and workforce policies and practices to increase collaboration and productivity. Table of Contents As a part of our culture, every employee is expected to challenge any unsafe act, complete each workday safely, and provide feedback on safety and security matters. In addition to comprehensive safety and security standards, and mandatory health, safety, and security training programs for applicable employees, we promote programs designed to encourage employees to provide feedback on practices or actions that could harm employees, customers, or the Ameren Companies, including perceived issues related to safety, security (both physical and cyber), ethics and compliance violations, or acts of discrimination. We seek to foster diversity, equity, and inclusion across our organization. We contribute to community-based organizations, hold diversity, equity, and inclusion leadership summits for employees and community leaders, and offer various training programs. We also offer a program to provide paid-time off for employees who engage in volunteer or learning opportunities with organizations that support diversity, equity, and inclusion. We also have employee resource groups, which bring together groups of employees who share common interests or backgrounds. Within these groups, employees collaborate to address concerns and provide training and development opportunities related to challenges or barriers, and offer support for each other, among other things. Leadership Amerens leaders play a critical role in setting and executing Amerens strategic initiatives, modeling our values and culture, and engaging and enabling the workforce. As such, we seek to develop a strong, diverse leadership team. Management engages in an extensive succession planning process annually, which includes the involvement of Amerens board of directors. We develop our leaders both individually, through job rotations, work experiences, and leadership development programs, and as a team, through collaborative learning and mentoring relationships. Throughout the year, we offer a variety of forums intended to connect our leaders to our mission, values, strategy and culture, build leadership skills and capabilities, and to promote connection and inclusion. In addition, we evaluate our organizational structure and make adjustments and expand roles to facilitate execution of our strategy and organizational efficiency. Talent In order to attract and retain a skilled and diverse workforce, we promote an inclusive work environment, provide opportunities for employees to expand their knowledge and skill sets, and support career development. Our talent management initiatives include a wide range of recruiting partnerships and programs, including those programs discussed below. Our onboarding efforts are designed to ensure early engagement, including the opportunity to participate in mentoring programs. Additionally, employees are encouraged to participate in technical, professional, and leadership development opportunities, and outreach initiatives to engage with the communities that we serve, among other things. As our business needs change, we remain focused on ensuring that our workforce has the tools and skills necessary to deliver on our strategic initiatives. We have established programs to recruit early and mid-career talent to further enhance the diversity of our workforce pipelines. These programs include skilled craft education and training for individuals interested in skilled craft roles, an intern/co-op program that serves as a pipeline for STEM-related careers, a career reentry program for experienced professionals transitioning from voluntary career breaks, a program for individuals transitioning from military service, and an early career rotation program. Additionally, each year management and the Human Resources Committee of Amerens board of directors review the diversity of our workforce, leadership team, and leadership development pipeline, as well as the actions taken to further enhance the diversity of our leadership team. Workforce The majority of our workforce is comprised of skilled-craft and STEM-related professional and technical employees. Our workforce has been stable, with a total attrition rate of 8% in 2022. The majority of employee attrition is attributable to employee retirements, generally allowing for thoughtful workforce and succession planning in advance of these planned transitions. The following table presents our employee count and their average tenure at

December 31, 2022, and the attrition rate in 2022: ##TABLE_START Employee Count Average Tenure (in years) Attrition Rate Ameren 9,244 13 8% Ameren Missouri 4,039 14 7% Ameren Illinois 3,243 13 8% Ameren Services 1,962 11 10% ##TABLE_ENDTable of Contents Amerens workforce is diverse in many ways. At the officer level, which represents 48 individuals, 19% are female, and 21% are racially and/or ethnically diverse. The following table presents our total employee population that is represented by a collective bargaining unit, is a female, or is racially and/or ethnically diverse at December 31, 2022: ##TABLE_START Collective Bargaining Unit Female (a) Racially and/or Ethnically Diverse (a) Ameren 47% 24% 16% Ameren Missouri 59% 17% 14% Ameren Illinois 55% 23% 13% Ameren Services 11% 40% 23% ##TABLE_END(a) Gender, race, and ethnicity were self-reported by our employees. The following table presents Amerens employees by generation at December 31, 2022: ##TABLE_START Generation Description Ameren Ameren Missouri Ameren Illinois Ameren Services Baby Boomer (birth years between 1946 and 1964) 17% 18% 16% 17% Generation X (birth years between 1965 and 1980) 41% 40% 40% 43% Millennials (birth years between 1981 and 1996) 38% 37% 40% 37% Generation Z/Post Millennial (birth years after 1997) 4% 5% 4% 3% ##TABLE_ENDCollective bargaining units at Amerens subsidiaries consist of the International Brotherhood of Electrical Workers, the International Union of Operating Engineers, the Laborers International Union of North America, the United Association of Plumbers and Pipefitters, and the United Government Security Officers of America. The Ameren Companies expect continued constructive relationships with their respective labor unions. The Ameren Missouri collective bargaining unit contracts expire in 2025 and 2026, which cover 4% and 96% of represented employees, respectively. The Ameren Illinois collective bargaining unit contracts expire in 2023 and 2026, which cover 8% and 92% of represented employees, respectively. Rewards The primary objective of our rewards program is to provide a total rewards package that attracts and retains a talented workforce and reinforces strong performance in a financially sustainable manner. Management continuously evaluates our core benefits in an effort to create a market-competitive, performance-based, shareholder-aligned total rewards package with a view towards balancing employee value and financial sustainability. We recognize that the rewards package required to attract and retain talent over the long term is about more than pay and benefits; it is about the total employee experience and support of their overall well-being. In addition to base salary, medical benefits, and retirement benefits, including pension for substantially all employees and 401(k) savings, our total rewards package includes short-term incentives and long-term stock-based compensation for certain employees. Further, we offer our employees various programs that encourage overall well-being, including wellness and employee assistance programs. We strive to provide a competitive and sustainable rewards package that supports our ability to attract, engage, and retain a talented and diverse workforce, while at the same time reinforcing and rewarding strong performance. INDUSTRY ISSUES We are facing issues common to the electric and natural gas utility industry. These issues include: the potential for changes in laws, regulations, enforcement efforts, and policies at the state and federal levels; corporate tax law changes, including the IRA, as well as additional interpretations, regulations, amendments, or technical corrections that affect the amount and timing of income tax payments, reduce or limit the ability to claim certain deductions and use carryforward tax benefits and/or credits, or result in rate base reductions; cybersecurity risks, cyber attacks, including ransomware and other ransom-based attacks, hacking, social engineering, and other forms of malicious cybersecurity and/or privacy events, which could result in the loss of operational control of energy centers and electric and natural gas transmission and distribution systems and/or the theft or inappropriate release of certain types of information, including sensitive customer, employee, financial, and operating system information; acts of sabotage, which have increased in frequency and severity within the utility industry, terrorism, and other intentionally disruptive acts; political, regulatory, and customer resistance to higher rates; the potential for more intense competition in generation, supply, and distribution, including new technologies and their declining costs; the impact and effectiveness of vegetation management programs; the potential for reliability issues as fossil-fuel-fired and nuclear generation facilities are retired and replaced with renewable energy generation sources, and the impact on available capacity, capacity prices, and customer rates; Table of Contents the need to place new transmission and generation facilities in service, which is dependent upon timely regulatory approvals and the availability of necessary labor and materials, among other things, to maintain grid reliability; the modernization of the electric grid to accommodate a two-way flow of electricity and increase capacity for distributed generation interconnection; net metering rules and other changes in existing regulatory frameworks and recovery mechanisms to address the allocation of costs to customers who own generation resources that enable them both to sell power to us and to purchase power from us through the use of our transmission and distribution assets; legislation or programs to encourage or mandate energy efficiency, energy conservation, and renewable sources of power, and the lack of consensus as to how those programs should be paid for; pressure and uncertainty on customer growth and sales volumes in light of economic conditions; distributed generation, energy storage, technological advances, and energy-efficiency or conservation initiatives; changes in the structure of the industry as a result of changes in federal and state laws, including the formation and growth of independent transmission entities; changes in the allowed ROE, including ROE incentive adders, on FERC-regulated electric transmission assets; the availability of fuel and fluctuations in fuel prices; the availability of materials and equipment, and the potential disruptions in supply chains; the availability of a skilled work force, including transferring the specialized knowledge of those who are nearing retirement to employees succeeding them; inflationary pressures on the prices of commodities, labor, services, materials, and supplies, increasing interest rates, and impacts associated with extended recovery periods from customers; the potential for reduced efficiency and productivity due to challenges of hybrid remote working arrangements for non-field employees; regulatory lag; the influence of macroeconomic factors on yields of United States Treasury securities and on the allowed ROE provided by regulators; higher levels of infrastructure and technology investments and adjustments to customer rates associated with the refund of excess deferred income taxes that have resulted in, and are expected to continue to result in, negative or decreased free cash flow, which is defined as cash flows from operating activities less cash flows from investing activities and dividends paid; the demand for access to renewable energy generation at rates acceptable to customers; public concerns about the siting of new facilities, and challenges that members of the public can assert against applications for governmental permits and other approvals required to site and build new facilities that can result in significant cost increases, delays and denial of the permits and approvals by the regulators; complex new and proposed environmental laws including statutes, regulations, and requirements, such as air and water quality standards, mercury emissions standards, limitations on the use of natural gas in generation, CCR management requirements, and potential CO 2 limitations, which may limit, or result in the cessation of, the operation of electric generating units; public concerns about the potential environmental impacts from the combustion of fossil fuels, as well as pressure from public interest groups regarding limiting the use of natural gas; certain investors concerns about investing in, as well as certain insurers concerns about providing coverage to, utility companies that have coal-fired generation assets; increasing scrutiny by investors and other stakeholders of ESG practices; aging infrastructure and the need to construct new power generation, transmission, and distribution facilities, which have long time frames for completion, with limited long-term ability to predict power and commodity prices and regulatory requirements; public concerns about nuclear generation, decommissioning, and the disposal of nuclear waste; industry reputational challenges resulting from inappropriate lobbying and similar activities by certain utility companies; and consolidation of electric and natural gas utility companies. We are monitoring all these issues. Except as otherwise noted in this report, we are unable to predict what impact, if any, these issues will have on our results of operations, financial position, or liquidity. For additional information, see Risk Factors under Part I, Item 1A, Outlook in Managements Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7, and Note 2 Rate and Regulatory Matters, Note 9 Callaway Energy Center, and Note 14 Commitments and Contingencies under Part II, Item 8, of this report. Table of Contents OPERATING STATISTICS The following tables present key electric and natural gas operating statistics for Ameren for the past three years: ##TABLE_START Electric Operating Statistics Year Ended December 31, 2022 2021 2020 Electric Sales kilowatthours (in millions): Ameren Missouri: Residential 13,915 13,366 13,267 Commercial 13,826 13,556 13,117 Industrial 4,090 4,151 4,158 Street lighting and public authority 76 81 88 Ameren Missouri retail load subtotal 31,907 31,154 30,630 Off-system sales 7,645 7,425 7,578 Ameren Missouri total 39,552 38,579 38,208 Ameren Illinois Electric Distribution (a) : Residential 11,708 11,620 11,491 Commercial 11,867 11,795 11,414 Industrial 10,981 11,076 10,674 Street lighting and public authority 410 430 442 Ameren Illinois Electric Distribution total 34,966 34,921 34,021 Eliminate affiliate sales (190) (412) (322) Ameren total 74,328 73,088 71,907 Electric Operating Revenues (in millions): Ameren Missouri: Residential $ 1,578 $ 1,445 $ 1,373 Commercial 1,219 1,126 1,025 Industrial 290 280 261 Other, including street lighting and public authority 171 170 155 Ameren Missouri retail load subtotal $ 3,258 $ 3,021 $ 2,814 Off-system sales and capacity 591 191 170 Ameren Missouri total $ 3,849 $ 3,212 $ 2,984 Ameren Illinois Electric Distribution: Residential $ 1,325 $ 933 $ 867 Commercial 768 545 486 Industrial 199 135 124 Other, including street lighting and public authority (36) 26 21 Ameren Illinois Electric Distribution total $ 2,256 $ 1,639 $ 1,498 Ameren Transmission: Ameren Illinois Transmission (b) $ 424 $ 365 $ 329 ATXI 192 199 194 Eliminate affiliate revenues (1) (2) Ameren Transmission total $ 615 $ 562 $ 523 Other and intersegment eliminations (139) (116) (94) Ameren total $ 6,581 $ 5,297 $ 4,911 ##TABLE_END(a) Sales for which power was supplied by Ameren Illinois as well as alternative retail electric suppliers. In 2022, 2021, and 2020, Ameren Illinois procured power on behalf of its customers for 28%, 23%, and 23%, respectively, of its total kilowatthour sales. (b) Includes $104 million, $66 million, and $52 million in 2022, 2021, and 2020, respectively, of electric operating revenues from transmission services provided to Ameren Illinois Electric Distribution. Table of Contents ##TABLE_START Electric Operating Statistics Year Ended December 31, 2022 2021 2020 Ameren Missouri fuel costs (cents per kilowatthour generated) (a) 1.41 1.46 1.38 Source of Ameren Missouri energy supply: Coal 61.6 % 73.0 % 67.3 % Nuclear 21.6 10.5 19.4 Hydroelectric 3.2 4.2 4.5 Wind 4.7 3.7 Natural gas 1.1 1.0 0.5 Methane gas and solar 0.2 0.2 0.5 Purchased power wind 0.8 0.6 0.6 Purchased power other 6.8 6.8 7.2 Ameren Missouri total 100.0 % 100.0 % 100.0 % ##TABLE_END(a) Ameren Missouri fuel costs exclude $(98) million, $1 million, and $(49) million in 2022, 2021, and 2020, respectively, for changes in FAC recoveries. ##TABLE_START Natural Gas Operating Statistics Year Ended December 31, 2022 2021 2020 Natural Gas Sales dekatherms (in millions): Ameren Missouri: Residential 8 7 7 Commercial 4 4 3 Industrial 1 1 1 Transport 9 9 9 Ameren Missouri total 22 21 20 Ameren Illinois Natural Gas: Residential 59 54 55 Commercial 18 16 15 Industrial 6 4 7 Transport 99 100 96 Ameren Illinois Natural Gas total 182 174 173 Ameren total 204 195 193 Natural Gas Operating Revenues (in millions): Ameren Missouri: Residential $ 119 $ 79 $ 76 Commercial 56 34 29 Industrial 7 4 4 Transport and other 15 24 16 Ameren Missouri total $ 197 $ 141 $ 125 Ameren Illinois Natural Gas: Residential $ 846 $ 657 $ 541 Commercial 221 172 136 Industrial 41 35 14 Transport and other 72 93 69 Ameren Illinois Natural Gas total $ 1,180 $ 957 $ 760 Other and intercompany eliminations (1) (1) (2) Ameren total $ 1,376 $ 1,097 $ 883 Rate Base Statistics At December 31, 2022 2021 2020 Rate Base (in billions): Electric transmission and distribution $ 15.4 $ 13.5 $ 12.1 Natural gas transmission and distribution 2.9 2.7 2.4 Coal generation: Labadie Energy Center 0.9 0.9 0.9 Sioux Energy Center 0.7 0.7 0.7 Rush Island Energy Center 0.4 0.4 0.4 Meramec Energy Center (retired in December 2022) 0.1 0.1 Coal generation total 2.0 2.1 2.1 Nuclear generation 1.5 1.5 1.5 Renewable generation (hydroelectric, wind, solar, methane gas) 1.5 1.5 1.0 Natural gas generation 0.3 0.3 0.3 Rate base total $ 23.6 $ 21.6 $ 19.4 ##TABLE_ENDTable of Contents AVAILABLE INFORMATION The Ameren Companies make available free of charge through Amerens website (www.amereninvestors.com) their annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports filed with or furnished to the SEC pursuant to Sections 13(a) or 15(d) of the Exchange Act as soon as reasonably possible after such reports are electronically filed with, or furnished to, the SEC. These documents are also available through the SECs website (www.sec.gov). Amerens website is a channel of distribution for material information about the Ameren Companies. Financial and other material information is routinely posted to, and accessible at, Amerens website. The Ameren Companies also make available free of charge through Amerens website the charters of Amerens board of directors Audit and Risk Committee, Human Resources Committee, Finance Committee, Nominating and Corporate Governance Committee, and Nuclear, Operations and Environmental Sustainability Committee; the corporate governance guidelines; a policy regarding communications to the board of directors; a policy and procedures document with respect to related-person transactions; a code of ethics applicable to all directors, officers and employees; a supplemental code of ethics for principal executive and senior financial officers; and a director nomination policy that applies to the Ameren Companies. The information on Amerens website, or any other website referenced in this report, is not incorporated by reference into this report. ITEM 1A. RISK FACTORS Investors should review carefully the following material risk factors and the other information contained in this report. The risks that the Ameren Companies face are not limited to those in this section. There may be further risks and uncertainties that are not presently known or that are not currently believed to be material that may adversely affect the results of operations, financial position, and liquidity of the Ameren Companies. REGULATORY AND LEGISLATIVE RISKS We are subject to extensive regulation of our businesses. We are subject to federal, state, and local regulation. The extensive regulatory frameworks, some of which are more specifically identified in the following risk factors, regulate, among other matters, the electric and natural gas utility industries; the rate and cost structure of utilities, including an allowed ROE; the operation of nuclear power plants; the construction and operation of generation, transmission, and distribution facilities; the acquisition, disposal, depreciation and amortization of assets and facilities; the electric transmission system reliability; and wholesale and retail competition. In the planning and management of our operations, we must address the effects of existing and proposed laws and regulations and potential changes in our regulatory frameworks, including initiatives by federal and state legislatures, RTOs, utility regulators, and taxing authorities, and actions by local jurisdictions that may affect the constructing or siting of facilities. Significant changes in the nature of the regulation of our businesses, including expiration or discontinuation of, or significant changes to, existing regulatory mechanisms, could require changes to our business planning and management of our businesses and could adversely affect our results of operations, financial position, and liquidity. Failure to obtain adequate rates or regulatory approvals in a timely manner; failure to obtain necessary licenses or permits from regulatory authorities; the impact of new or modified laws, regulations, standards, interpretations, or other legal requirements; or increased compliance costs could adversely affect our results of operations, financial position, and liquidity. The electric and natural gas rates that we are allowed to charge are determined through regulatory proceedings, which are subject to intervention and appeal. Rates are also subject to legislative actions, which are largely outside of our control. Certain events could prevent us from recovering our costs in a timely manner or from earning adequate returns on our investments. The rates that we are allowed to charge for our utility services significantly influence our results of operations, financial position, and liquidity. The electric and natural gas utility industry is highly regulated. The utility rates charged to customers are determined by governmental entities, including the MoPSC, the ICC, and the FERC. Decisions by these entities are influenced by many factors, including the cost of providing service, the prudency of expenditures, the quality of service, regulatory staff knowledge and experience, customer intervention, and economic conditions, as well as social and political views. Decisions made by these governmental entities regarding customer rates are largely outside of our control. We are exposed to regulatory lag, including the impact of inflationary pressures, and cost disallowances to varying degrees by jurisdiction, which, if unmitigated, could adversely affect our results of operations, financial position, and liquidity. Rate orders are also subject to appeal, which creates additional uncertainty as to the rates that we will ultimately be allowed to charge for our services. From time to time, our regulators may approve trackers, riders, or other recovery mechanisms that allow electric or natural gas rates to be adjusted without a traditional regulatory rate review. These mechanisms could be changed or terminated. Ameren Missouris electric and natural gas utility rates and Ameren Illinois natural gas utility rates are typically established in regulatory proceedings that take up to 11 months to complete. Ameren Missouris electric and natural gas utility rates established in those proceedings are primarily based on historical costs, revenues, and sales volumes. Ameren Illinois natural gas rates established in those proceedings are Table of Contents based on estimated future costs, revenues, and sales volumes. Beginning in 2024 through at least 2027, Ameren Illinois electric distribution rates will be established through an MYRP as discussed in the following risk factor, which will be based on estimated future costs and an applicable revenue requirement reconciliation, which may not allow for full recovery of actual costs due to a reconciliation cap. Thus, the rates that we are allowed to charge for utility services may not match our actual costs at any given time. Rates include an allowed return on investments established by the regulator, including a return at the applicable WACC on rate base, and an amount for income taxes based on the currently applicable statutory income tax rates and amortization associated with excess deferred income taxes. Although rate regulation is premised on providing an opportunity to earn a reasonable rate of return on rate base, there can be no assurance that the regulator will determine that our costs were prudently incurred or that the regulatory process will result in rates that will produce full recovery of such costs or provide for an opportunity to earn a reasonable return on those investments. Ameren Missouri and Ameren Illinois, and the utility industry generally, have an increased need for cost recovery, primarily driven by capital investments, which is likely to continue in the future. The resulting increase to the revenue requirement needed to recover such costs and earn a return on investments could result in more frequent regulatory rate reviews and requests for cost recovery mechanisms. Additionally, increasing rates could result in regulatory or legislative actions, as well as competitive or political pressures, all of which could adversely affect our results of operations, financial position, and liquidity. Ameren Illinois is utilizing the IEIMA performance-based formula ratemaking framework to establish annual customer rates effective through 2023. Effective for rates beginning in 2024 through at least 2027, Ameren Illinois will establish electric distribution rates through an MYRP, which is subject to a reconciliation cap and includes an ROE determined by the ICC applicable to each year of the four-year period. As a result of its participation in the IEIMA performance-based formula ratemaking, Ameren Illinois ROE for its electric distribution service through 2023 and its electric energy-efficiency investments are directly correlated to yields on United States Treasury bonds. Additionally, Ameren Illinois is subject to certain performance standards. Ameren Illinois is utilizing the IEIMA performance-based formula ratemaking framework to establish annual customer rates effective through 2023 and will reconcile the related revenue requirements through an IEIMA reconciliation. The IETL resulted in changes to the regulatory framework applicable to Ameren Illinois electric distribution business by giving Ameren Illinois the option to file an MYRP with the ICC by mid-January 2023, with rates effective beginning in 2024, or establish future rates through a traditional regulatory rate review, among other things. An MYRP would establish rates for a four-year period, and Ameren Illinois has the option to file for an MYRP every four years. Ameren Illinois elected to file an MYRP in January 2023 for rates effective in 2024 through 2027 with the ICC. The MYRP also allows Ameren Illinois to reconcile its actual revenue requirement, as adjusted for certain cost variations, to ICC-approved electric distribution service rates on an annual basis, subject to a reconciliation cap. The reconciliation cap limits the annual adjustment to 105% of the annual revenue requirement approved by the ICC. Certain variations from forecasted costs would be excluded from the reconciliation cap, including those associated with major storms; new business and facility relocations; changes in the timing of certain expenditures or investments into or out of the applicable calendar year; and changes in interest rates, income taxes, taxes other than income taxes, pension and other post-retirement benefits costs, and amortization of certain assets. The reconciliation cap also excludes costs recovered through riders outside of base rates, such as riders for electric energy-efficiency investments, power procurement and transmission services, renewable energy credit compliance, zero emission credits, certain environmental costs, and bad debt write-offs, among others. Ameren Illinois existing riders will remain effective and electric distribution service revenues will continue to be decoupled from sales volumes under the MYRP. The actual revenue requirement for a particular year would incorporate Ameren Illinois year-end rate base and actual capital structure for such year, provided that the common equity ratio in such capital structure may not exceed that approved by the ICC in the MYRP. In addition, the ICC will determine the ROE applicable to each year of the four-year period. Changes in economic conditions could result in the predetermined ROE becoming inadequate over the four-year period. By law, Ameren Illinois electric distribution revenues are decoupled from sales volumes regardless of the process used to establish electric distribution rates, which ensures that the electric distribution revenues authorized in a regulatory rate review are not affected by changes in sales volumes. Ameren Illinois electric energy-efficiency program rider, which includes a return at the applicable WACC on its program investments, is subject to performance-based formula ratemaking. The ICC annually reviews each Ameren Illinois rate filing for reasonableness and prudency. If the ICC were to conclude that Ameren Illinois costs were not prudently incurred, the ICC would disallow recovery of such costs. The allowed ROE under the IEIMA and electric energy-efficiency formula ratemaking recovery mechanisms is based on the annual average of the monthly yields of the 30-year United States Treasury bonds plus 580 basis points. Therefore, Ameren Illinois annual ROE for its electric distribution business is directly correlated to the yields on such bonds, which are outside of Ameren Illinois control. A 50 basis point change in the annual average of the monthly yields of the 30-year United States Treasury bonds would result in an estimated $12 million change in Amerens and Ameren Illinois annual net income, based on Ameren Illinois 2023 projected year-end rate base, including electric energy-efficiency investments. Ameren Illinois electric distribution business is also subject to performance standards. Failure to achieve the standards would result in a reduction in the companys allowed ROE calculated under the formula ratemaking recovery mechanisms. The performance standards applicable to electric distribution service under the IEIMA include improvements in service reliability to reduce both the frequency and duration of outages, a reduction in the number of estimated bills, a reduction of consumption from inactive meters, and a reduction in bad Table of Contents debt expense. The 2023 allowed ROE for electric distribution service is subject to the performance standards related to reduced estimated bills and bad debt expense, and may be decreased for penalties up to 10 basis points if these performance standards are not met. The allowed ROE on energy-efficiency investments can be increased or decreased up to 200 basis points, depending on the achievement of annual energy savings goals. Any adjustments to the allowed ROE for energy-efficiency investments will depend on annual performance for a historical period relative to energy savings goals. In 2022, 2021, and 2020, there were no performance-related basis point adjustments that materially affected financial results. With respect to the MYRP, a September 2022 ICC order approved total ROE incentives and penalties of 24 basis points, allocated among the seven performance metrics. These performance metrics include improvements in service reliability in both the frequency and duration of outages, a reduction in peak loads, an increased percentage of spend with diverse suppliers, a reduction in disconnections for certain customers, and improved timeliness in response to customer requests for interconnection of distributed energy resources. These performance metrics and the ROE incentives and penalties will apply annually from 2024 through 2027 under the MYRP filed by Ameren Illinois. While the ICC has approved a plan for Ameren Illinois to invest approximately $120 million per year in electric energy-efficiency programs through 2025, the ICC has the ability to reduce the amount of electric energy-efficiency savings goals in the future plan program years if there are insufficient cost-effective programs available, which could reduce the investments in electric energy-efficiency program s. With respect to its natural gas delivery service business, unless extended, Ameren Illinois QIP will expire after December 2023. The QIP provides Ameren Illinois with recovery of, and a return on, qualifying natural gas infrastructure investments that are placed in service between regulatory rate reviews. Infrastructure investments under the QIP earn a return at the applicable WACC. Ameren Illinois QIP is subject to a rate impact limitation of a cumulative 4% per year since the most recent delivery service rate order, with no single year exceeding 5.5%. If the rate impact limitation was met in a particular year, the amount of rate base causing the QIP rate to exceed the limitation would be exposed to regulatory lag until a year when that amount could be recovered under QIP or is added to rate base as a part of a regulatory rate review. Upon issuance of a natural gas delivery service rate order, QIP rate base is transferred to base rates and the QIP is reset to zero. Without legislative action, the QIP will expire after December 2023. If Ameren Illinois is unable to recover investments under the QIP or there is no other regulatory change, Ameren Illinois will be subject to increased regulatory lag on its natural gas infrastructure investments that are placed in service between regulatory rate reviews, which could adversely affect Amerens and Ameren Illinois investment plans and results of operations, financial position, and liquidity. As a result of the election to use the PISA, Ameren Missouris electric service rates are subject to a rate cap through 2023. Effective 2024, Ameren Missouris electric service business is subject to a limitation on increasing the annual revenue requirement due to the inclusion of incremental PISA deferrals in the revenue requirement. Ameren Missouris rate cap under the PISA is effective through 2023 and limits electric service rate increases to a 2.85% compound annual growth rate in the average overall customer rate per kilowatthour, based on the electric rates that became effective in April 2017, less half of the annual savings from the TCJA that was passed on to customers as approved in a July 2018 MoPSC order. Increased capital investments and operating costs could cause customer rates to exceed the 2.85% rate cap effective through 2023. In addition, a decrease in off-system sales or capacity revenues or an increase in purchased power expense, all of which are included in net energy costs within the FAC, could also contribute to customer rates exceeding the rate cap. Off-system sales are affected by generation availability, which is affected by planned and unplanned outages at Ameren Missouris energy centers, curtailment of generation resulting from unfavorable economic conditions, the addition of new generation sources, and retirements of Ameren Missouris energy centers, among other things. If rate changes from the FAC or the RESRAM riders would cause rates to temporarily exceed the 2.85% rate cap, the overage would be deferred for future recovery in the next regulatory rate review; however, rates established in such regulatory rate review would be subject to the rate cap. Any deferred overages approved for recovery would be recovered over a period of 20 years following approval of amounts in a regulatory rate review. Excluding customer rates under the MEEIA rider, which are not subject to the rate cap, Ameren Missouri would incur a penalty equal to the amount of deferred overage that would cause customer rates to exceed the 2.85% rate cap until new rates are established in the next regulatory rate review. A penalty incurred as the result of exceeding the rate cap could adversely affect Amerens and Ameren Missouris results of operations, financial position, and liquidity. Also, d ue to a change in customer behavior and certain business practices resulting from the COVID-19 pandemic, there has been a shift in sales volumes by customer class at Ameren Missouri, which began in 2020, resulting in an increase in residential sales, and a decrease in commercial and industrial sales. While Ameren Missouri's electric sales volumes in 2022, excluding the estimated effects of weather and customer energy-efficiency programs, were comparable to the same period in 2021 and to pre-pandemic levels, l ong-term declines in sales volumes, along with increased capital investments and operating costs, could result in Ameren Missouris inability to recover amounts exceeding the rate cap. Missouri Senate Bill 745 became effective on August 28, 2022. The law extended Ameren Missouris PISA election through December 2028 and allows for an additional extension through December 2033 if requested by Ameren Missouri and approved by the MoPSC, among other things. The law established a 2.5% annual limit on increases to the electric service revenue requirement used to set customer rates due to the inclusion of incremental PISA deferrals in the revenue requirement. The limitation will be effective for revenue requirements approved Table of Contents by the MoPSC after January 1, 2024, and will be based on the revenue requirement established in the immediately preceding rate order. Increased capital expenditures could cause incremental PISA deferrals to exceed the 2.5% limitation when it is effective, and such amounts exceeding the 2.5% limitation would be excluded from recovery under future revenue requirements. Failure to align capital investments under the 2.5% limitation could adversely affect Amerens and Ameren Missouris results of operations, financial position, and liquidity. We are subject to various environmental and permitting laws. Significant capital expenditures may be required to achieve and to maintain compliance with these environmental laws. Failure to comply with these laws could result in the closing of facilities, alterations to the manner in which these facilities operate, increased operating costs, delays and increased costs of building new facilities, or exposure to fines and liabilities. Our electric generation, transmission, and distribution and natural gas distribution and storage operations must comply with a variety of statutes and regulations relating to the protection of the environment and human health and safety including permitting programs implemented by federal, state, and local authorities. Such environmental laws address air emissions; discharges to water bodies; the storage, handling and disposal of hazardous substances and waste materials; siting and land use requirements; and potential ecological impacts. Complex and lengthy processes are required to obtain and renew approvals, permits, and licenses for new, existing, or modified facilities. Additionally, the use and handling of various chemicals or hazardous materials require release prevention plans and emergency response procedures. Further, we are subject to risks from changing or conflicting interpretations of existing laws, modification to existing laws, new laws, and new or modified permit terms. We are also subject to liability under environmental laws that address the remediation of environmental contamination on property currently or formerly owned by us or by our predecessors, as well as property contaminated by hazardous substances that we generated. Such properties include MGP sites, substations, and third-party sites, such as landfills. Additionally, private individuals may seek to enforce environmental laws against us. They could allege injury from exposure to hazardous materials, allege a failure to comply with environmental laws, seek to compel remediation of environmental contamination, or seek to recover damages resulting from that contamination. Environmental regulations have a significant impact on the electric utility industry and compliance with these regulations could be costly for Ameren Missouri, which operates coal-fired power plants. As of December 31, 2022, Ameren Missouris coal-fired energy centers represented 9% and 17% of Amerens and Ameren Missouris rate base, respectively. Regulations under the Clean Air Act that apply to the electric utility industry include the NSPS, the CSAPR, the MATS, and the National Ambient Air Quality Standards, which are subject to periodic review for certain pollutants. Collectively, these regulations cover a variety of pollutants, such as SO_2, particulate matter, NO_x, mercury, toxic metals, and acid gases, and CO_2 emissions from new power plants. Regulations implementing the Clean Water Act govern both intake and discharges of water, as well as evaluation of the ecological and biological impact of our operations and could require modifications to water intake structures or more stringent limitations on wastewater discharges. Depending upon the scope of modifications ultimately required by state regulators, capital expenditures associated with these modifications could be significant. The management and disposal of coal ash is regulated under the Resource Conservation and Recovery Act and the CCR Rule, which require the closure of our surface impoundments at Ameren Missouris coal-fired energy centers. The individual or combined effects of compliance with existing and new environmental regulations could result in significant capital expenditures, increased operating costs, or the closure or alteration of operations at some of Ameren Missouris energy centers. In January 2011, the United States Department of Justice, on behalf of the EPA, filed a complaint against Ameren Missouri in the United States District Court for the Eastern District of Missouri alleging that projects performed in 2007 and 2010 at the coal-fired Rush Island Energy Center violated provisions of the Clean Air Act and Missouri law. In January 2017, the district court issued a liability ruling against Ameren Missouri and, in September 2019, entered a remedy order. That remedy order included a requirement to install a flue gas desulfurization system at the Rush Island Energy Center, which was upheld through an appeals process by the United States Court of Appeals for the Eighth Circuit in the fourth quarter of 2021. Based on its assessment of available legal, operational and regulatory alternatives, Ameren Missouri filed a motion in December 2021 with the district court to modify the remedy order to allow the retirement of the Rush Island Energy Center in advance of its previously expected useful life in lieu of installing a flue gas desulfurization system. The March 31, 2024 compliance date contained in the district courts September 2019 remedy order remains in effect unless extended by the district court. In July 2022, in response to an Ameren Missouri request for a final, binding reliability assessment, the MISO designated the Rush Island Energy Center as a system support resource and concluded that certain mitigation measures, including transmission upgrades, should occur before the energy center is retired. The transmission upgrade projects have been approved by the MISO, and design and procurement activities necessary to complete the upgrades are underway. Ameren Missouri expects to complete the upgrades by mid-2025. In October 2022, the FERC approved a system support resource agreement, which became effective retroactively as of September 1, 2022. The agreement details the manner of continued operation for a system support resource that results in operating during peak demand times and emergencies. The system support resource designation and the related agreement are subject to annual renewal and revision. In September 2022, the Rush Island Energy Center began operating consistent with the system support resource agreement. In addition, in October 2022, the FERC established hearing and settlement procedures in response to an August 2022 request from Ameren Missouri for recovery of non-energy costs under the related MISO tariff. The FERC is under no deadline to issue an order related to this proceeding. Revenues and costs under the MISO tariff are expected to be included in the FAC. The district court has the authority to determine the Table of Contents retirement date and operating parameters for the Rush Island Energy Center and is not bound by the MISO determination of the Rush Island Energy Center as a system support resource or the FERCs approval. The district court is under no deadline to issue a ruling modifying the remedy order. Related to this matter, i n February 2022, the MoPSC issued an order directing the MoPSC staff to review Ameren Missouris planned accelerated retirement of the Rush Island Energy Center, including potential impacts on the reliability and cost of Ameren Missouris service to its customers; Ameren Missouris plans to mitigate the customer impacts of the accelerated retirement; and the prudence of Ameren Missouris actions and decisions with regard to the Rush Island Energy Center, among other things. In April 2022, the MoPSC staff filed an initial report with the MoPSC in which the staff concluded early retirement of the Rush Island Energy Center may cause reliability concerns. The MoPSC staff is under no deadline to complete this review. Ameren Missouri expects to seek approval from the MoPSC to finance the costs associated with the retirement, including the remaining unrecovered net plant balance associated with the facility, through the issuance of securitized utility tariff bonds pursuant to Missouris securitization statute. If the remaining unrecovered net plant balance for the Rush Island Energy Center and an associated return are not recoverable through base rates or other regulatory mechanisms, Ameren Missouri would recognize an abandonment loss equal to the difference between the remaining net book value of the asset and the present value of the expected future cash flows. As of December 31, 2022, the Rush Island Energy Center had a net plant balance of approximately $0.6 billion and a rate base of approximately $0.4 billion. Ameren Missouri is unable to predict the ultimate resolution of this matter; however, such resolution could have a material adverse effect on the results of operations, financial position, and liquidity of Ameren and Ameren Missouri. In June 2022, the United States Supreme Court issued its decision in West Virginia v. EPA, clarifying that there are limits on how the EPA may regulate greenhouse gases absent further direction from the United States Congress. The court concluded that emission caps designed to shift generation from fossil-fuel-fired power plants to renewable energy facilities would require specific congressional authorization and that such authorization had not been given under the Clean Air Act. The decision by the United States Supreme Court may affect the EPAs development of any new regulations to address CO_2 emissions from coal- and natural gas-fired power plants; however, at this time, Ameren Missouri cannot predict the impact of any such regulations or the decision by the United States Supreme Court on the results of operations, financial position, and liquidity of Ameren or Ameren Missouri. The IETL established emission standards that became effective in September 2021. Ameren Missouri's natural gas-fired energy centers in Illinois will be subject to limits on emissions, including CO_2 and NO_x, equal to their unit-specific average annual emissions from 2018 through 2020, for any rolling twelve-month period beginning October 1, 2021, through 2029. Further reductions to emissions limits will become effective between 2030 and 2040, resulting in the closure of the Venice Energy Center by 2029. The reductions could also limit the operations of Ameren Missouri's four natural gas-fired energy centers located in the state of Illinois, and will result in their closure by 2040. These energy centers are utilized to support peak loads. Subject to conditions in the IETL, these energy centers may be allowed to exceed the emissions limits in order to maintain reliability of electric utility service. Ameren and Ameren Missouri have incurred, and expect to incur, significant costs with respect to environmental compliance and site remediation. New or revised environmental regulations, enforcement initiatives, or legislation could result in a significant increase in capital expenditures and operating costs, decreased revenues, penalties or fines, reduced operations or closure of some of Ameren Missouris coal-and natural gas-fired energy centers, which, in turn, could lead to increased liquidity and financing needs, and higher financing costs. Actions required to ensure that Ameren Missouris facilities and operations are in compliance with environmental laws could be prohibitively expensive for Ameren Missouri if the costs are not fully recovered through rates. Environmental laws could require Ameren Missouri to close or to alter significantly the operations of its energy centers. If Ameren Missouri requests recovery of capital expenditures and costs for environmental compliance through rates, the MoPSC could deny recovery of all or a portion of these costs, prevent timely recovery, or make changes to the regulatory framework in an effort to minimize rate volatility and customer rate increases. Capital expenditures and costs to comply with future legislation or regulations might result in Ameren Missouri closing coal-fired energy centers earlier than planned. If these costs are not recoverable through base rates or other regulatory mechanisms, it could lead to an impairment of assets and reduced revenues. Any of the foregoing could have an adverse effect on our results of operations, financial positions, and liquidity. We are subject to business and financial risks related to the impact of climate change legislation, regulation, and emission reduction goals. There is increasing concern and activism among various external stakeholders, both nationally and internationally, about climate change, including public concerns about the potential environmental impacts from the combustion of fossil fuels, as well as pressure from public interest groups regarding limiting the use of natural gas. Federal, state, and local authorities, including the United States Congress, have considered initiatives to further restrict greenhouse gases to address global climate change. Additionally, international agreements could lead to future federal or state legislation or regulations. In 2015, the United Nations Framework Convention on Climate Change reached consensus among approximately 190 nations on an agreement, known as the Paris Agreement, that establishes a framework for greenhouse gas mitigation actions by all countries, with a goal of holding the increase in global average temperature to below 2 degrees Celsius above pre-industrial levels and an aspiration to limit the increase to 1.5 degrees Celsius. The Biden administration has a policy commitment regarding a reduction in greenhouse gas emissions for the United States, but rulemaking to achieve such reductions has not yet been implemented. Actions taken to implement the Paris Agreement could result in future additional greenhouse gas reduction requirements in the Table of Contents United States. In addition, the EPA has announced plans to implement new climate change programs, including potential regulation of greenhouse gas emissions targeting the utility industry. As a result of our diverse fuel portfolio, our emissions of greenhouse gases vary among our energy centers, but coal-fired power plants are significant sources of CO_2 emissions. Future federal and state legislation or regulations that mandate limits on the emission of, or impose taxation on, greenhouse gases could result in a significant increase in capital expenditures and operating costs, decreased revenues, penalties or fines, or reduced operations of some of Ameren Missouris coal- and natural gas-fired energy centers, which, in turn, could lead to increased liquidity and financing needs, and higher financing costs. Moreover, to the extent Ameren Missouri requests recovery of these costs through rates, its regulators might deny some or all of, or defer timely recovery of, these costs. Excessive costs to comply with future legislation or regulations related to climate change might force Ameren Missouri to close some coal-fired energy centers earlier than planned, which could lead to possible loss on abandonment and reduced revenues. As a result, mandatory limits could have a material adverse impact on Amerens and Ameren Missouris results of operations, financial position, and liquidity. Ameren is targeting net-zero carbon emissions by 2045, as well as a 60% reduction by 2030 and an 85% reduction by 2040 based on 2005 levels. Amerens goals include both direct emissions from operations, as well as electricity usage at Ameren buildings, including other greenhouse gas emissions of methane, nitrous oxide, and sulfur hexafluoride. Achievement of these goals is dependent on many factors, including the pace and extent of development and deployment of low- to zero-carbon energy technologies and carbon capture technologies, and the cost of those technologies; natural gas prices; new transmission infrastructure; the ability to maintain system reliability during the transition to clean energy generation; and constructive energy and economic policies, including those that address investment in energy infrastructure, global climate change, incentives for clean energy technologies, and environmental regulations. Additional factors associated with operational risks for the construction and acquisition of electric and natural gas infrastructure may also affect the achievement of these goals, as further discussed below. The strategy to achieve these goals also relies on continuing to pursue a diverse portfolio including low-carbon and carbon-free resources and energy-efficiency resources; continuing to participate in efforts to help advance the development of technologies such as carbon capture, utilization, and sequestration; the use of hydrogen fuel for electric production and energy storage, next generation nuclear, and large-scale long-cycle battery energy storage; and constructively engaging with legislators, regulators, investors, customers, and other stakeholders to support outcomes leading to a net-zero future. We are subject to regulatory compliance and proceedings, which could result in increasing costs, regulatory penalties, and/or other sanctions. We are subject to FERC regulations, rules, and orders, including standards required by the NERC. As owners and operators of bulk power transmission systems and electric energy centers, we are subject to mandatory NERC reliability standards, including cybersecurity standards. In addition, our natural gas transmission, distribution, and storage facilities systems are subject to PHMSA rules and regulations. Compliance with these reliability standards, rules, and regulations may subject us to higher operating costs and may result in increased capital expenditures. We may also incur higher operating costs to comply with potential new regulations issued by these regulatory bodies. If we were found not to be in compliance with these mandatory NERC reliability standards, PHMSA rules and regulations, or FERC regulations, rules, and orders, we could incur substantial monetary penalties and other sanctions, which could adversely affect our results of operations, financial position, and liquidity. The FERC can impose civil penalties of approximately $1.5 million per violation per day for violation of its regulations, rules, and orders, including mandatory NERC reliability standards. The FERC also conducts audits and reviews of Ameren Missouris, Ameren Illinois, and ATXIs accounting records to assess the accuracy of their respective formula ratemaking process, and it can require refunds to customers for previously billed amounts, with interest. Additionally, pursuant to the IETL, Illinois utilities are subject to new requirements and provisions related to ethical conduct and transparency, including submitting an annual ethics and compliance report to the ICC. The law authorizes the

ICC to initiate an investigation into how customer funds were used if ethical misconduct is determined to have occurred at an Illinois utility, potentially requiring the utility to issue refunds and imposing a potential penalty of up to $0.5 million per violation. OPERATIONAL RISKS The construction and acquisition of, and capital improvements to, electric and natural gas utility infrastructure, along with Ameren Missouris ability to implement its Smart Energy Plan, which is aligned with its 2022 Change to the 2020 IRP, involve substantial risks. We expect to make significant capital expenditures to maintain and improve our electric and natural gas utility infrastructure and to comply with existing environmental regulations. We estimate that we will invest up to $20.5 billion (Ameren Missouri up to $10.8 billion; Ameren Illinois up to $9.5 billion; ATXI up to $0.2 billion) of capital expenditures from 2023 through 2027. For additional information on these estimates, see Liquidity and Capital Resources Capital Expenditures in Managements Discussion and Analysis of Financial Condition and Results of Operations under Part II, Item 7, of this report. Investments in Amerens rate-regulated operations are expected to be recoverable from customers, but they are subject to prudence reviews and are exposed to regulatory lag of varying degrees by jurisdiction. Table of Contents Our ability to complete construction projects successfully within projected estimates, including schedule, performance, and/or cost, and to implement Ameren Missouris Smart Energy Plan, which may include acquisition of generation facilities after they are constructed, is contingent upon many factors and subject to substantial risks. These factors include, but are not limited to, the following: project management expertise; escalating costs and/or shortages for labor, materials, and equipment, including changes to tariffs on materials or government actions; the ability of suppliers, contractors, and developers to meet contractual commitments and timely complete projects; changes in the scope and timing of projects; the ability to obtain required regulatory, project, and permit approvals; the ability to obtain necessary rights-of-way, easements, and transmission connections at an acceptable cost in a timely fashion; unsatisfactory performance by the projects when completed; the inability to earn an adequate return on invested capital; the ability to raise capital on reasonable terms; and other events beyond our control, including construction delays due to weather. With respect to the transition of Ameren Missouris generation fleet and carbon emission reduction targets outlined in the 2022 Change to the 2020 IRP, factors also include MoPSC approval for the retirement of energy centers and new or continued customer energy-efficiency programs; the ability to enter into build-transfer agreements for renewable generation and acquire that generation at a reasonable cost; levels of customer participation in the energy-efficiency programs; the cost and commercial availability of wind, solar, and other renewable generation and battery storage technologies; the cost of natural gas or hydrogen CT technologies; the ability to qualify for, and use or transfer, federal production or investment tax credits; changes in environmental laws or requirements, including those related to CO_2 and other greenhouse gas emissions; and energy prices and demand. In addition, government investigations relating to the importation of solar panel components could affect the cost and the availability of solar panel components. Any of these risks could result in higher costs, the inability to complete anticipated projects, or facility closures, and could adversely affect our results of operations, financial position, and liquidity. Our electric generation, transmission, and distribution facilities are subject to operational risks. Our financial performance depends on the successful operation of electric generation, transmission, and distribution facilities. Operation of electric generation, transmission, and distribution facilities involves many risks, including: facility shutdowns due to operator error, or a failure of equipment or processes; longer-than-anticipated maintenance outages; failures of equipment that can result in unanticipated liabilities or unplanned outages; aging infrastructure that may require significant expenditures to operate and maintain; lack of adequate water required for cooling plant operations and to operate hydroelectric energy centers; labor disputes; disruptions in the delivery of electricity to our customers; inability to maintain reliability of our electric utility services as coal-fired energy centers are retired and renewable energy generation is placed in service; disruptions to the global supply chain as a result of shortages for labor, materials, or equipment, international trade relations, delivery delays, economic pressures, including increased interest rates and inflation, and the impact of COVID-19, among other things; suppliers and contractors who do not perform as required under their contracts, including those obligations that are affected by supply chain disruptions; failure of other operators facilities and the effect of that failure on our electric system and customers; inability to comply with regulatory or permit requirements, including those relating to environmental laws; handling, storage, and disposition of CCR; unusual or adverse weather conditions or other natural disasters, including those that may result from climate change, such as severe storms, droughts, floods, tornadoes, earthquakes, icing, sustained high or low temperatures, solar flares, and electromagnetic pulses; the level of wind and solar resources; inability to operate wind generation facilities at full capacity resulting from requirements to protect natural resources, including wildlife; the occurrence of catastrophic events such as fires, explosions, acts of sabotage, which have increased in frequency and severity within the utility industry, acts of terrorism, civil unrest, pandemic health events, including the COVID-19 pandemic, or other similar events; accidents that might result in injury or loss of life, extensive property damage, or environmental damage; ineffective vegetation management programs; cybersecurity risks, including loss of operational control of Ameren Missouris energy centers and our transmission and distribution systems and loss of data, including sensitive customer, employee, financial, and operating system information, through insider or outsider actions; limitations on amounts of insurance available to cover losses that might arise in connection with operating our electric generation, transmission, and distribution facilities; inability to implement or maintain information systems; failure to keep pace with and the ability to adapt to rapid technological change; and other unanticipated operations and maintenance expenses and liabilities. Table of Contents The foregoing risks could affect the controls and operations of our facilities or impede our ability to meet regulatory requirements, which could increase operating costs, increase our capital requirements and costs, reduce our revenues, or have an adverse effect on our liquidity. Ameren Missouris ability to obtain an adequate supply of coal could limit operation of its coal-fired energy centers. Ameren Missouri owns and operates coal-fired energy centers. About 97% of Ameren Missouris coal is purchased from the Powder River Basin in Wyoming, which has a limited number of suppliers. Deliveries from the Powder River Basin have occasionally been restricted because of rail congestion, staffing and equipment issues, infrastructure maintenance, derailments, weather, and supplier financial hardship. Coal suppliers in the Powder River Basin are experiencing financial hardship because of a decrease in demand resulting from increased natural gas use and renewable energy generation, and the impact of environmental regulations and concerns related to coal-fired generation. These financial hardships have resulted in bankruptcy filings by certain coal suppliers in recent years. As of December 31, 2022, coal inventories at the Labadie and Sioux energy centers were below targeted levels due to transportation delays in 2022. Additional delays or disruptions in the delivery of coal, failure of our coal suppliers to provide adequate quantities or quality of coal, or lack of adequate inventories of coal, including low-sulfur coal used to comply with environmental regulations, could have adverse effects on Ameren Missouris electric generation operations. If Ameren Missouri is unable to obtain an adequate supply of coal under existing agreements, it may be required to purchase coal at higher prices or be forced to reduce generation at its coal-fired energy centers, which could adversely affect Amerens and Ameren Missouris results of operations, financial position, and liquidity. Ameren Missouris ownership and operation of a nuclear energy center creates business, financial, and waste disposal risks. Ameren Missouris ownership of the Callaway Energy Center subjects it to risks associated with nuclear generation, including: potential harmful effects on the environment and human health resulting from radiological releases associated with the operation of nuclear facilities and the storage, handling, and disposal of radioactive materials; continued uncertainty regarding the federal governments plan to permanently store spent nuclear fuel and, as a result, the need to provide for long-term storage of spent nuclear fuel at the Callaway Energy Center; limitations on the amounts and types of insurance available to cover losses that might arise in connection with the Callaway Energy Center or other United States nuclear facilities; uncertainties about contingencies and retrospective premium assessments relating to claims at the Callaway Energy Center or other United States nuclear facilities; public and governmental concerns about the safety and adequacy of security at nuclear facilities; limited availability of fuel supply and our reliance on licensed fuel assemblies from the one NRC-licensed supplier of Callaway Energy Centers assemblies; costly and extended outages for scheduled or unscheduled maintenance and refueling; uncertainties about the technological and financial aspects of decommissioning nuclear facilities at the end of their licensed lives; the ability to continue to attract and maintain qualified labor to operate the Callaway Energy Center; the adverse effect of poor market performance and other economic factors on the asset values of nuclear decommissioning trust funds and the corresponding increase, upon MoPSC approval, in customer rates to fund the estimated decommissioning costs; and potential adverse effects of a natural disaster, acts of sabotage or terrorism, including a cyber attack, or any accident leading to a radiological release. The NRC has broad authority under federal law to impose licensing and safety requirements for nuclear facilities. In the event of noncompliance, the NRC has the authority to impose fines or to shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated from time to time by the NRC could necessitate substantial capital expenditures at the Callaway Energy Center. In addition, if a serious nuclear incident were to occur, it could adversely affect Amerens and Ameren Missouris results of operations, financial condition, and liquidity. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation of any domestic nuclear unit and could also cause the NRC to impose additional conditions or requirements on the industry, which could increase costs and result in additional capital expenditures. While the Callaway Energy Center is in compliance with the current NRC standards relating to seismic design and risk, these standards also require Ameren Missouri to address periodic changes to seismic hazard data and evaluation methods for the impact of an earthquake on its Callaway Energy Center due to its proximity to a fault line, which could require seismic risk evaluation updates and installation of additional capital equipment. Our natural gas distribution service businesses involve numerous risks that may result in accidents and increased operating costs. Inherent in our natural gas distribution businesses, which includes transmission, distribution, and storage facilities, are a variety of hazards and operating risks, such as leaks, explosions, mechanical problems and cybersecurity risks, which could cause substantial financial losses, including fines and penalties. In addition, these hazards could result in serious injury, loss of human life, significant damage to property, environmental impacts, and impairment of our operations, which in turn could lead us to incur substantial losses. The location of Table of Contents transmission and distribution mains and storage facilities near populated areas, including residential areas, business centers, industrial sites, and other public gathering places, could increase the level of damages resulting from these risks. A major domestic incident involving natural gas facilities could result in additional capital expenditures and/or increased operations and maintenance expenses for us and increased regulation of natural gas utilities. The occurrence of any of these events could adversely affect our results of operations, financial position, and liquidity. Significant portions of our electric generation, transmission, and distribution facilities and natural gas transmission and distribution facilities are aging. This aging infrastructure may require significant additional maintenance or replacement. Ameren Missouri could be adversely affected if it is unable to recover the remaining investment, if any, and decommissioning costs associated with the retirement of an energy center, as well as the ability to earn a return on that remaining investment and those decommissioning costs. Our aging infrastructure may pose risks to system reliability and expose us to expedited or unplanned significant capital expenditures and operating costs. All of Ameren Missouris coal-fired energy centers were constructed prior to 1978, and the Callaway Energy Center began operating in 1984. The age of these energy centers increases the risks of unplanned outages, reduced generation output, and higher maintenance expense. Further, Ameren Missouri would be adversely affected if the MoPSC does not allow recovery of the remaining investment and decommissioning costs associated with the retirement of an energy center, as well as the ability to earn a return on that remaining investment and those decommissioning costs. In addition, as discussed above, Ameren Missouri expects the retirement date of its Rush Island Energy Center to be accelerated from the date reflected in depreciation rates approved in the December 2021 MoPSC electric rate order. Aging transmission and distribution facilities are more prone to failure than new facilities, which results in higher maintenance expense and the need to replace these facilities with new infrastructure. Even when the system is properly maintained, its reliability may ultimately deteriorate and negatively affect our ability to serve our customers, which could result in increased costs associated with regulatory oversight. The frequency and duration of customer outages are among the IEIMA and IETL performance standards. Any failure to achieve these standards will result in a reduction in Ameren Illinois allowed ROE on electric distribution assets. The higher maintenance costs associated with aging infrastructure and capital expenditures for new or replacement infrastructure, compounded by increasing interest rates and inflationary pressures, could cause additional rate volatility for our customers, resistance by our regulators to allow customer rate increases, and/or regulatory lag in some of our jurisdictions, any of which could adversely affect our results of operations, financial position, and liquidity. Energy conservation, energy efficiency, distributed generation, energy storage, technological advances, and other factors could reduce energy demand from our customers. Without a regulatory mechanism to ensure recovery, declines in energy usage could result in an under-recovery of our revenue requirement or an increase in our customer rates, as the revenue requirement would be spread over less sales volumes, which could adversely affect our results of operations, financial position, and liquidity. Such declines could occur due to a number of factors, including: customer energy-efficiency programs that are designed to reduce energy demand; energy-efficiency efforts by customers not related to our energy-efficiency programs; increased customer use of distributed generation sources, such as solar panels and other technologies, which have become more cost-competitive, with decreasing costs expected in the future, as well as the use of energy storage technologies; and macroeconomic factors resulting in low economic growth or contraction within our service territories, which could reduce energy demand. Decreased use of our generation, transmission, and distribution services might result in stranded costs, which ultimately might not be recovered through rates, and therefore could lead to an impairment or abandonment of assets. FINANCIAL, ECONOMIC, AND MARKET RISKS Amerens holding company structure could limit its ability to pay common stock dividends and to service its debt obligations. Ameren is a holding company; therefore, its primary assets are its investments in the common stock of its subsidiaries, including Ameren Missouri, Ameren Illinois, and ATXI. As a result, Amerens ability to pay dividends on its common stock depends on the earnings of its subsidiaries and the ability of its subsidiaries to pay dividends or otherwise transfer funds to Ameren. Similarly, Amerens ability to service its debt obligations is dependent upon the earnings of its operating subsidiaries and the distribution of those earnings and other payments, including payments of principal and interest under affiliate indebtedness. The payment of dividends to Ameren by its subsidiaries in turn depends on their results of operations, and other items affecting retained earnings, and available cash. Amerens subsidiaries are separate and distinct legal entities and have no obligation, contingent or otherwise, to pay any dividends or make any other distributions (except for payments required pursuant to the terms of affiliate borrowing arrangements and cash payments under the tax allocation agreement) to Ameren. Under the IRA, a 15% minimum tax on adjusted financial statement income, as defined in the law, is assessed against corporations whose average annual adjusted financial statement income exceeds $1 billion for three consecutive preceding tax years, effective for tax Table of Contents years beginning after December 31, 2022. Once a corporation exceeds this three-year average annual adjusted financial statement income threshold, it will be subject to the minimum tax for all future tax years. As Ameren files a consolidated income tax return, it is reliant on its subsidiaries to pay the minimum tax once the threshold is exceeded. The payments related to the minimum tax by Ameren Missouri, Ameren Illinois, and ATXI are expected to be recovered, subject to approval by their respective regulators. Certain financing agreements, corporate organizational documents, and certain statutory and regulatory requirements may impose restrictions on the ability of Ameren Missouri, Ameren Illinois, and ATXI to transfer funds to Ameren in the form of cash dividends, loans, or advances. Significant increases in prices of commodities, labor, services, materials, and supplies and other costs, including costs associated with our defined benefit retirement and postretirement plans, health care plans, and other employee benefits, could adversely affect our results of operations, financial position, or liquidity. A part of our core strategy focuses on disciplined cost management, including prudently monitoring all of our expenses. However, we have observed inflationary pressures related to prices of commodities, labor, services, materials and supplies, and other costs. We are uncertain whether these inflationary pressures will continue and at what rate. These inflationary pressures, as well as increasing interest rates, could impact our ability to control costs, to make substantial investments in our businesses, to recover costs and investments, to earn our allowed ROEs within frameworks established by our regulators, and/or to maintain affordability of our services for our customers. In addition, these inflationary pressures and increasing interest rates could adversely affect our customers usage of, or payment for, our services. Additionally, volatility in the commodities market could increase collateral postings and prepayments. Also, market volatility could significantly affect the investment performance of Amerens COLI. Significant increases in our costs could increase our financing needs and otherwise adversely affect our results of operations, financial position, and liquidity. For additional information on purchased power costs, see Outlook under Part II, Item 7, of this report. Related to benefits, Ameren has defined benefit pension plans covering substantially all of its employees and has postretirement benefit plans covering non-union employees hired before October 2015 and union employees hired before January 2020. Assumptions related to future costs, returns on investments, interest rates, timing of employee retirements, and mortality, as well as other actuarial matters, have a significant impact on our customers rates and our plan funding requirements. Amerens total pension and postretirement benefit plans were overfunded by $377 million as of December 31, 2022. Ameren expects to fund its pension plans at a level equal to the greater of the pension cost or the legally required minimum contribution. Based on its assumptions at December 31, 2022, its investment performance in 2022, and its pension funding policy, Ameren does not expect to make material contributions in 2023 through 2025, and expects to make aggregate contributions of $170 million in 2026 and 2027. Ameren Missouri and Ameren Illinois estimate that their portion of the future funding requirements will be 40% and 50%, respectively. These estimated contributions may change based on actual investment performance, changes in interest rates, changes in our assumptions, changes in government regulations, and any voluntary contributions. In addition to the costs of our pension plans, the costs of providing health care benefits to our employees and retirees have increased in recent years. We believe that our employee benefit costs, including costs of health care plans for our employees and former employees, will continue to rise. Future legislative changes related to health care could also significantly change our benefit programs and costs. GENERAL RISKS Customers, investors, legislators, regulators, and creditors opinions of us are affected by many factors, including system reliability, implementation of our strategic plan, protection of customer information, rates, media coverage, and ESG practices, as well as actions by other utility companies. Negative opinions developed by customers, investors, legislators, regulators, and creditors could harm our reputation. Our results are influenced by the expectations of our customers, investors, legislators, regulators, and creditors. Those expectations are based, in part, on the reliability and affordability of our utility services. Service interruptions and facility shutdowns can occur due to failures of equipment as a result of severe or destructive weather or other causes. The ability of Ameren Missouri and Ameren Illinois to respond promptly to such failures can affect customer satisfaction. In addition to system reliability issues, the success of modernization efforts, our ability to safeguard sensitive customer information and protect our systems from cyber attacks, and other actions can affect customer satisfaction. The level of rates, the timing and magnitude of rate increases, and the volatility of rates can also affect regulator and customer satisfaction. Our ability to successfully execute our strategic plan, including the transition of Ameren Missouris generation fleet and achievement of the carbon emission reduction targets outlined in the 2022 Change to the 2020 IRP, may affect customers, investors, legislators, regulators, and creditors opinions and actions. Additionally, negative perceptions or publicity resulting from increasing scrutiny of ESG practices could negatively impact our reputation, investment in our common stock, or our access to capital markets. Customers, investors, legislators, regulators, and creditors opinions of us can also be affected by media coverage, including social media, which may include information, whether factual or not, that damages our brand and reputation. If customers, investors, legislators, regulators, or creditors have or develop a negative opinion of us and our utility services, this could result in increased costs associated with regulatory oversight and could affect the ROEs we are allowed to earn, as well as the access to, and Table of Contents the cost of, capital. Additionally, negative opinions about us or other utility companies could make it more difficult for our businesses to achieve favorable legislative or regulatory outcomes. Negative opinions could also result in sales volume reductions or increased use of distributed generation by our customers. Any of these consequences could adversely affect our results of operations, financial position, and liquidity. We are subject to employee work force factors that could adversely affect our operations. Our businesses depend upon our ability to employ and retain key officers and other skilled professional and technical employees. Certain specialized knowledge that focuses on skilled-craft and STEM-related disciplines is required to construct and operate generation, transmission, and distribution assets. Further, a significant portion of our work force is nearing retirement. As of December 31, 2022, approximately 25%, 25%, and 23% of Amerens, Ameren Missouris, and Ameren Illinois total employees were 55 years old or older, respectively. We are also party to collective bargaining agreements that collectively represent about 47%, 59%, and 55% of Amerens, Ameren Missouris and Ameren Illinois total employees, respectively. The Ameren Missouri collective bargaining unit contracts expire in 2025 and 2026, which cover 4% and 96% of represented employees, respectively. The Ameren Illinois collective bargaining unit contracts expire in 2023 and 2026, which cover 8% and 92% of represented employees, respectively. Remote working arrangements could increase our data security risks, including loss of data related to sensitive customer, employee, financial, and operating system information, through insider or outsider actions. Certain events, such as significant delays in finding appropriate replacement talent, inadequately trained replacement employees, a mismatch of skill sets to future needs, any work stoppage experienced in connection with negotiations of collective bargaining agreements, or challenges with remote working arrangements, could adversely affect our operations. Our operations are subject to acts of sabotage, terrorism, cyber attacks, and other intentionally disruptive acts. Like other electric and natural gas utilities, our energy centers, fuel storage facilities, transmission and distribution facilities, and enterprise information systems may be affected by malicious acts, terrorist activities and other intentionally disruptive acts, including physical and cyber attacks, which could disrupt our ability to produce or distribute our energy products. In the industry, there continues to be attacks on energy infrastructure, such as substations and related assets. The threat landscape continues to expand, which may result in more attacks in the future. Any such incident could limit our ability to generate, purchase, or transmit power or natural gas and could have significant regional economic consequences. Any such disruption could result in a significant decrease in revenues, a significant increase in costs including those for repair, or adversely affect economic activity in our service territory which, in turn, could adversely affect our results of operations, financial position, and liquidity. There has been an increase in the number and sophistication of physical and cyber attacks across all industries worldwide. Physical attacks could include sabotaging, vandalizing, or burglarizing transmission and distribution facilities, which are unmanned, widely dispersed, and often in isolated areas, or the theft of physical data and information. Cyber attacks could include viruses, malicious or destructive code, phishing attacks, denial of service attacks, supply chain attacks, ransomware and other extortion-based attacks, improper access by third parties, attacks on email systems, and attacks leading to data loss, operational control, or exploitation of vulnerabilities specific to internally developed systems or to those provided and/or maintained by our suppliers, among various other security breaches. A security breach of our physical assets or in our information systems could affect the reliability of the transmission and distribution system, disrupt electric generation, including nuclear generation, and/or subject us to financial harm resulting from theft or the inappropriate release or destruction of certain types of information, including sensitive customer, employee, financial, and operating system information. Many of our suppliers, vendors, contractors, and information technology providers have access to systems that support our operations and maintain customer and employee data. A breach of these third-party systems could adversely affect our business as if it was a breach of our own system. If a significant breach occurred, our reputation could be adversely affected, customer confidence could be diminished, availability of our services could be impacted, and/or we could be subject to increased costs associated with regulatory oversight, fines or legal claims, any of which could result in a significant decrease in revenues or significant costs for remedying the impacts of such a breach. Our generation, transmission, and distribution systems are part of an interconnected grid. Therefore, a disruption caused by a physical or cyber incident at another utility, electric generator, RTO, or commodity supplier could also adversely affect our businesses. Insurance might not be adequate to cover losses that arise in connection with these events. In addition, new regulations could require changes in our security measures and result in increased costs. The occurrence of any of these events could adversely affect our results of operations, financial position, and liquidity. Our businesses are dependent on our ability to access the capital markets successfully. We might not have access to sufficient capital in the amounts and at the times needed, as well as on reasonable terms. We rely on the issuance of short-term and long-term debt and equity as significant sources of liquidity and funding for capital requirements not satisfied by our operating cash flow, as well as to refinance existing long-term debt. The inability to raise debt or equity capital on reasonable terms, or at all, could negatively affect our ability to maintain or to expand our businesses. General economic factors beyond our control might create uncertainty that could increase our cost of capital or impair or eliminate our ability to access the debt, equity, or credit markets, including our ability to draw on bank credit facilities. These factors include depressed economic conditions, a recession, Table of Contents increasing interest rates, inflation, sanctions, trade restrictions, political instability, war, terrorism, and extreme volatility in the debt, equity, or credit markets. Any adverse change in our credit ratings could reduce access to capital and trigger collateral postings and prepayments. Such changes could also increase the cost of borrowing and the costs of fuel, power, and natural gas supply, among other things, which could adversely affect our results of operations, financial position, and liquidity.

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Item 1. Business This annual report on Form 10-K is a combined report being filed by two separate Registrants, American States Water Company (AWR) and Golden State Water Company (GSWC). References in this report to Registrant are to AWR and GSWC, collectively, unless otherwise specified. GSWC makes no representations as to the information contained in this report relating to AWR and its subsidiaries, other than GSWC. AWR makes its periodic reports, Form 10-Q and Form 10-K, and current reports, Form 8-K, available free of charge through its website, www.aswater.com, as soon as material is electronically filed with or furnished to the Securities and Exchange Commission (SEC). Such reports are also available on the SECs website at www.sec.gov. AWR also makes available free of charge its code of business conduct and ethics, its corporate governance guidelines and the charters of its Nominating and Governance Committee, Compensation Committee and Audit and Finance Committee through its website or by calling (877) 463-6297. AWR and GSWC have filed the certification of officers required by Section 302 of the Sarbanes-Oxley Act as Exhibits 31.1 and 31.2 to this Form 10-K for fiscal 2022. Overview AWR is the parent company of GSWC, Bear Valley Electric Service, Inc. (BVESI) and American States Utility Services, Inc. (ASUS) (and its wholly owned subsidiaries: Fort Bliss Water Services Company (FBWS), Terrapin Utility Services, Inc. (TUS), Old Dominion Utility Services, Inc. (ODUS), Palmetto State Utility Services, Inc. (PSUS), Old North Utility Services, Inc. (ONUS), Emerald Coast Utility Services, Inc. (ECUS) and Fort Riley Utility Services, Inc. (FRUS)). On July 1, 2020, GSWC completed the transfer of the electric utility assets and liabilities from its electric division to BVESI, in exchange for common shares of BVESI. GSWC then immediately distributed all of BVESIs common shares to AWR, whereupon BVESI became wholly owned directly by AWR. This reorganization did not result in any substantive changes to AWRs operations and business segments. AWR has three reportable segments: water, electric and contracted services. Within the segments, AWR has three principal business units, water and electric service utility operations conducted through its regulated utilities GSWC and BVESI, respectively, and contracted services conducted through ASUS and its subsidiaries. FBWS, TUS, ODUS, PSUS, ONUS, ECUS and FRUS may be referred to herein collectively as the Military Utility Privatization Subsidiaries. GSWC is a public water utility engaged in the purchase, production, distribution and sale of water in 10 counties in the state of California. GSWC is regulated by the California Public Utilities Commission (CPUC). BVESI is a public electric utility that distributes electricity in several San Bernardino County mountain communities in California, and is also regulated by the CPUC. Additional information regarding public utility regulation is discussed in Item 7. Managements Discussion and Analysis of Financial Condition" and Results of Operations under the section titled Regulatory Matters . AWRs regulated utilities served 263,265 water customers and 24,705 electric customers at December 31, 2022, or a total of 287,970 customers, compared with 262,770 water customers and 24,656 electric customers at December 31, 2021, or a total of 287,426 customers. Both GSWCs and BVESIs operations exhibit seasonal trends. Although both have diversified customer bases, residential and commercial customers account for the majority of water and electric sales and revenues. Revenues derived from commercial and residential customers accounted for approximately 90% of total water and electric revenues for the years ended December 31, 2022, 2021 and 2020. ASUS, through the Military Utility Privatization Subsidiaries, has contracted with the U.S. government to provide water and/or wastewater services at various military installations. ASUS operates, maintains and performs construction activities (including renewal and replacement capital work) on water and/or wastewater systems at various U.S. military bases pursuant to an initial 50-year firm, fixed price contract and additional firm, fixed-price contracts. Each of the contracts with the U.S. government is subject to termination, in whole or in part, prior to the end of its 50-year term for convenience of the U.S. government or as a result of default or nonperformance by the ASUS subsidiary performing the contract. The price for each of these contracts is subject to annual economic price adjustments. Contracts are also subject to modifications for changes in circumstances, changes in laws and regulations, and additions to the contract value for new construction of facilities at the military bases. AWR guarantees performance of ASUSs military privatization contracts. Pursuant to the terms of the 50-year contract with the U.S. government, the Military Utility Privatization Subsidiaries operate the following water and wastewater systems: ##TABLE_START Subsidiary Military Base Type of System Location FBWS Fort Bliss Water and Wastewater Texas and New Mexico TUS Joint Base Andrews Water and Wastewater Maryland ODUS Fort Lee Wastewater Virginia ODUS Joint-Base Langley Eustis and Joint Expeditionary Base Little Creek-Fort Story Water and Wastewater Virginia PSUS Fort Jackson Water and Wastewater South Carolina ONUS Fort Bragg, Pope Army Airfield and Camp Mackall Water and Wastewater North Carolina ECUS Eglin Air Force Base Water and Wastewater Florida FRUS Fort Riley Water and Wastewater Collection and Treatment Kansas ##TABLE_ENDCertain financial information for each of AWRs business segments - water distribution, electric distribution, and contracted services - is set forth in Note 17 to the Notes to Consolidated Financial Statements of American States Water Company and its subsidiaries. While AWRs water and electric utility segments are not dependent upon a single or only a few customers, the U.S. government is the primary customer for ASUSs contracted services. ASUS, from time to time, performs work at military bases for other prime contractors of the U.S. government. Seasonality The demand for water and electricity varies by season. For instance, there can be a higher level of water consumption during the third quarter of each year when weather in California tends to be hot and dry. During unusually wet weather, our customers generally use less water. The CPUC has adopted regulatory mechanisms at GSWC that help mitigate fluctuations in revenues due to changes in water consumption by our customers in California, which currently remain in effect. The demand for electricity in our electric customer service area is greatly affected by winter snow levels. An increase in winter snow levels reduces the use of snow making machines at ski resorts in the Big Bear area and, as a result, reduces our electric revenues. Likewise, unseasonably warm weather during a skiing season may result in temperatures too high for snow making conditions, which also reduces our electric revenues. The CPUC has adopted regulatory mechanisms for our electric business, which helps mitigate fluctuations in the revenues of our electric business due to changes in the amount of electricity used by BVESIs customers. Environmental Regulations AWRs subsidiaries are subject to extensive environmental regulations. GSWC is required to comply with safe drinking water requirements, including testing to determine constituents in its water supply and customer notification requirements if certain contaminants exceed maximum levels or advisory levels, and requirements to address issues relating to known contamination. The subsidiaries of ASUS are subject to similar requirements in connection with their water and wastewater operations on military bases. GSWC is also responsible for clean-up and remediation at a plant site that contained an underground storage tank. As mandated by legislation enacted in California, BVESI is required to submit wildfire mitigation plans to the CPUC for approval. California requires all electric utilities to prepare plans on constructing, maintaining, and operating their electrical lines and equipment to minimize the risk of catastrophic wildfire. ASUSs subsidiaries are responsible for ensuring compliance with the reduction and/or removal of all constituents required under its wastewater treatment plant operating permits. ASUS works closely with state regulators and industry associations to stay current with emergent issues and proactively addresses any change in wastewater treatment regulation to ensure permit compliance. The regulated utilities spent approximately $21.7 million in 2022 and expect to spend approximately $24.3 million in 2023 for capital expenditures on environmental control facilities. During 2022, ASUS performed construction activities (for the benefit of the U.S. government) related to environmental control facilities with a contract value of $922,000. ASUS expects to perform construction activities related to environmental control facilities with a contract value of $1.7 million in 2023. In addition, various other capital expenditures at the regulated utilities and construction projects at ASUS are incurred for purposes other than environmental control facilities, but may also have some environmental benefits. An environmental control facility is any facility that is reasonably expected to abate, reduce or aid in the prevention, measurement, control of monitoring of noise, air or water pollutants, solid waste, thermal pollution, radiation or other pollutants. Environmental matters and compliance with such laws and regulations are discussed further in Item 7. Managements Discussion and Analysis of Financial Condition and Results of Operations under the section titled Environmental Matters . Climate Change Planning, Risks and Opportunities Climate change is one area that we focus on as we develop and execute our business strategy and financial planning, both in the short- and long-term and is subject to the oversight of the Board of Directors and senior management. First and foremost, designing and implementing efficient and resilient infrastructure and operational processes not only addresses climate change, but also reduces costs. Our capital investment programs are critical to ensure we can continue delivering reliable, high-quality water, wastewater and electric services without interruption. As a utility company, our operating strategy is dependent on having a reliable infrastructure in place. The risks posed by climate variability increase the need for us to plan for and address supply resiliency. We address these risks by planning, assessing, mitigating, and investing in our infrastructure for the long-term benefit of our communities. As a provider of an essential product and service, our primary goal is to ensure service is uninterrupted. GSWC considers the potential impacts of climate change in its water supply portfolio planning and its overall infrastructure replacement plans. We evaluate how water supplies, water quality and water demands may change, and consider mitigation strategies to assist us in being able to deliver water to our customers. We seek to minimize our greenhouse gas (GHG) emissions to assist in reducing the effects of climate change. We studied our GHG emissions levels, set a 2020 baseline, and developed a GHG emissions reduction target of 60% by 2035 from the 2020 baseline. To accomplish this, Registrant has developed a phased approach, which includes short-, medium- and long-term actions. Our priorities include reductions in energy use and increasing purchases of green energy for our water operations, increasing purchases of green energy for distribution to our electric customers, and reviewing our vehicle fleet needs and electrification. Achievement of this reduction target is contingent on certain external factors, which include the ongoing development of technology, and successful achievement by the state of California in reaching its Renewables Portfolio Standard goal for this period. Water Utility There are risks to maintaining adequate water quality and/or supply, either from climate variability or other events. They include droughts, changes in weather patterns, natural disasters, wildfires, decisions or actions restricting the use of water from our sources, and/or pumping of groundwater, and contamination or acts of terrorism or vandalism. We consider these potential events in our strategic planning process as we aim to avoid service interruptions and compromised water quality. Our goal is to maintain adequate and high-quality water supplies. We strive to reach this goal in a number of ways, including monitoring water levels, short- and long-term water supply planning, having a diverse water supply portfolio, developing contingency plans, water efficiency and conservation efforts, and maintaining a strong infrastructure. Additional information on GSWCs water supplies is discussed further in Item 7. Managements Discussion and Analysis of Financial Condition and Results of Operation under the section titled Water Supplies . Electric Utility Climate change has also impacted electric utilities in California due to an increase in wildfires. BVESIs compliance with its wildfire mitigation plans have resulted in an increase in capital expenditures for wildfire mitigation projects. BVESI will not be able to recover the costs incurred to make capital improvements included in BVESIs current wildfire mitigation plans from customers until the CPUC approves recovery of these costs in its next general rate case filing, which was filed in August 2022 and will determine new electric rates for the years 2023-2026. Power supplies may also become more constrained and more expensive due to regulation of power plants using fossil fuels. California has established a cap-and-trade program applicable to greenhouse gas emissions. While BVESIs power-plant emissions are below the reporting threshold, as a Covered Entity BVESI has an obligation to file a report with the California Air Resources Board (CARB) in June of each year under the Greenhouse Gas Mandatory Reporting Regulation. The report will become available publicly in the last quarter of 2023. The State of California and the CPUC have established renewable energy procurement targets. BVESI has entered into a CPUC-approved ten-year contract for renewable energy credits. Because of this agreement, BVESI believes it will comply through at least 2023 with Californias renewable energy statutes that address this issue. BVESI is pursuing short- and long-term renewable energy contracts to satisfy its requirements related to its resource portfolio for compliance period 4 (2021-2024) and beyond. In 2022, BVESIs renewable power represented 38.5% of total electric supply purchases. Renewable Energy Procurement requirements continue to escalate, reaching 50% by 2026 and 100% carbon free by 2045. BVESI has issued a proposal to construct a solar energy project in Big Bear Lake, subject to obtaining CPUC approval and necessary permits. If approved and constructed, the project will provide a clean, local energy solution for the service territory. BVESI offers a Distributed Generation Program, which benefits customers who install a solar or wind-generating facility that produces renewable energy. Those customers can receive a bill credit if their monthly renewable energy production exceeds their on-site use. BVESI also has a number of customers on its Net Energy Metering Program (NEM), which was the previous renewable energy program. NEM customers can receive a bill credit if their annual renewable energy production exceeds their on-site use. Approximately 5% of the energy consumed by our BVESI customers is now generated by customer-owned renewable sources (solar). BVESI is also required to comply with the CPUCs greenhouse gas emission performance standards. Under these standards, BVESI must file an annual attestation with the CPUC stating that BVESI has no new ownership investment in generation facilities exceeding the emission performance standards and no long-term commitments for generation exceeding the standards. In January 2023, BVESI filed an attestation that BVESI complied with the standards for 2022. At this time, management cannot estimate the impact, if any, that these regulations may have on future costs over BVESIs power plant operations or the cost of BVESIs purchased power from third party providers. COVID-19 GSWC, BVESI and ASUS have continued their operations throughout the COVID-19 pandemic given that their water, wastewater and electric utility services are deemed essential. AWRs responses take into account orders issued by the CPUC, and continued monitoring of guidance provided by federal, state, and local health authorities and other government officials for the COVID-19 pandemic. Some of the actions taken by GSWC and BVESI included suspending service disconnections for nonpayment pursuant to CPUC and state orders, and telecommuting by employees. The suspension of water-service disconnections at GSWC were implemented in response to an executive order from the governor of California, as well as CPUC orders. Pursuant to a CPUC July 2021 decision, the moratorium on water-service disconnections due to non-payment of past-due amounts billed to residential customers expired on February 1, 2022. However, water service cannot be disconnected so long as customers make timely payments on current bills, and are provided and adhere to payment plans to pay down past-due bills resulting from the pandemic. The moratorium on electric customer service disconnections ended on September 30, 2021. However, electric-service disconnections for non-payment can only be done after taking into account other matters, such as average daily temperatures under certain conditions, and residential disconnections are capped on an annual basis at 2.5% of the total residential customers during the previous calendar year. With the CPUCs moratoriums on service disconnections for nonpayment for water and electric customers ending, service disconnections due to nonpayment have resumed with disconnections for delinquent residential customers resuming in June 2022. The COVID-19 pandemic and its lingering effects to the economy contributed to significant volatility in financial markets throughout the pandemic. The continued economic impact could adversely impact the value of GSWCs pension and other retirement plan assets due to possible declines in security prices. In addition, the lingering effects of the pandemic has placed a strain on supply chains to sufficiently meet demand of materials and supplies necessary to complete some capital expenditure projects at our regulated utilities, as well as some construction projects at our contracted services segment. While we may purchase materials and supplies upfront when appropriate, there can be no assurance that our efforts will prevent delays or disruptions to our capital investments or construction projects. Furthermore, Registrant has experienced increased costs due to the impacts of inflation. The regulated utilities may update their costs as part of general rate case proceedings or advice letter filings, as related to COVID-19 emergency costs. ASUS may update prices annually through economic price adjustments. However, until we receive increased funding to offset higher costs, our liquidity may be negatively impacted. Additional information regarding the impact of COVID-19 on GSWC and BVESI is provided in Item 7. Managements Discussion and Analysis of Financial Condition and Results of Operation under the section titled COVID-19 . Competition The businesses of GSWC and BVESI are substantially free from direct and indirect competition with other public utilities, municipalities and other public agencies within their existing service territories. However, GSWC and BVESI may be subject to eminent domain proceedings in which governmental agencies, under state law, may acquire GSWCs water systems or BVESIs electric system if doing so is necessary and in the publics interest. GSWC competes with governmental agencies and other investor-owned utilities in connection with offering service to new real estate developments on the basis of financial terms, availability of water and ability to commence providing service on a timely basis. ASUS actively competes for business with other investor-owned utilities, other third-party providers of water and/or wastewater services, and governmental entities primarily on the basis of quality of service and price. AWR Workforce AWR and its subsidiaries had a total of 811 employees as of December 31, 2022. GSWC had 501 employees as of December 31, 2022. BVESI had 46 employees, of which 17 employees are covered by a collective bargaining agreement with the International Brotherhood of Electrical Workers, which expires in December 2025. All of the employees of GSWC and BVESI are located in California. At times, GSWC and BVESI use temporary and contract workers for a finite period of time and in a limited capacity to continue a project or workflow until they can hire a regular employee. It is also common for those temporary workers to be hired on as a regular, full-time employee. ASUS and its subsidiaries had a total of 264 employees as of December 31, 2022. Fifteen of FBWSs employees are covered by a collective bargaining agreement with the International Union of Operating Engineers. This agreement expires in September 2023. Our businesses requires a combination of complex infrastructure, regulatory expertise and customer service. Ongoing development of our talent across the organization to meet critical business needs is a continual focus, and includes (i) building a culture such that high-potential talent is identified and further developed, (ii) creating career paths that not only move up a specialized ladder, but across the organization, and (iii) offering opportunities for employees to accept new challenges through stretch assignments. Attracting Diverse Candidates We understand that strength comes from having a diverse employee population. We strive to hire from our local communities and have a workforce that is representative, at all job levels, of the communities we serve. This begins with the recruitment process. We strive to have all aspects of employment, including the decision to hire, promote, discipline, or discharge, be based on merit, competence, performance, and business needs. It is our policy not to discriminate on the basis of race, color, religion, marital status, age, national origin, ancestry, physical or mental disability, medical condition, pregnancy, genetic information, gender, sexual orientation, gender identity or expression, veteran status, or any other status protected under federal, state, or local laws. Compensation and Benefits We pay employees a competitive and fair wage, as benchmarked with other leading companies and the market. Consistent with our principle of valuing personal mastery, we reward employees for improving their skills and capabilities. Our benefits include a defined benefit pension plan for employees hired prior to January 1, 2011, a defined contribution plan for hires or rehires after December 31, 2010, a 401(k) plan, healthcare and insurance benefits, health savings and flexible spending accounts. Safety and Training Strong Occupational Health and Safety practices reduce injuries, keep our workforce healthy, and reduce operating costs. A safe workforce translates into better performance company-wide. We work to create a safety-focused culture in which each individual feels personally responsible for their own safety, the safety of their co-workers, as well as the safety of the communities they serve. Safety performance is included as a metric in the officer and manager compensation programs. Employees attend training in various mandated safety programs that are applicable to their operations. In addition, there are regulatory safety training requirements as well as training requirements for the Department of Transportation and training requirements for compliance with local, state, and federal environmental laws. To reinforce our safety efforts and protocols, company-wide safety inspections at GSWC and BVESI are conducted with supervisors. The inspection reports are forwarded to management for review, allocation of resources are made (if needed), and corrective actions are taken. ASUS has a dedicated Safety Coordinator located at each military base installation served. The onsite Safety Coordinator is responsible for regulatory compliance, as well as beneficial health and safety monitoring functions. Learning and Development Compliance training is required each year, for each employee. Other types of training are offered on an optional basis. Examples of optional programs include ongoing water operations competencies and education, supervisor development, knowledge capture and management, feedback and measurements to show the value of learning solutions, and administrative oversight for various business competencies relative to mandated training and compliance requirements. We pay for approved external business-related seminars and workshops. Certain positions require employees to maintain all of their job-specific certifications, licenses and continuing education credits. On a regular and ongoing basis, we require all employees to certify that they have reviewed and understand our Code of Conduct as well as our Employee Handbook. We provide harassment and prevention awareness training for all employees. Succession Planning On an annual basis, our senior management team completes a roadmap for improving human capital management by developing succession plans with the goal of achieving the most efficient alignment of resources and talent to meet business needs. This includes identifying key succession positions and potential successors for top-level positions, such as Vice Presidents, for the next ten years. Recruiting, developing and retaining the right talent is key to our long-term success. With 30% of our employees eligible for retirement in the next five years, we are focused on transferring institutional knowledge, continue succession planning and pursue recruitment and development strategies to attract qualified talent. Cybersecurity Cyberattacks represent an increasing threat to water, wastewater and electric utility systems and thereby the safety and security of our communities. There have also been increasing threats to the information that companies maintain that have resulted in the unauthorized disclosure of private customer, employee, director and corporate financial information. We have increased our investments in information technology to monitor and address these threats and attempted cyber-attacks, and to improve our posture in addressing security vulnerabilities. We have adopted multi-layered safeguards and educational measures to protect our operations, assets and digital information. Cybersecurity updates are given to the Board of Directors on a quarterly basis. Quarterly cybersecurity training is required for all employees, with the topics varying each quarter. We also conduct specialized training for employees annually on protecting certain types of information relating to the work we do with the U.S. government. While we have increased our investments in information technology and in employee awareness and education to address security vulnerabilities, there can be no assurance that these measures and our efforts will prevent a cyber-attack. Forward-Looking Information This Form 10-K and the documents incorporated herein contain forward-looking statements intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. Forward-looking statements are based on current estimates, expectations and projections about future events and assumptions regarding these events and include statements regarding managements goals, beliefs, plans or current expectations, taking into account the information currently available to management. Forward-looking statements are not statements of historical facts. For example, when we use words such as anticipate, believe, plan, estimate, expect, intend, may and other words that convey uncertainty of future events or outcomes, we are making forward-looking statements. We are not able to predict all the factors that may affect future results. We caution you that any forward-looking statements made by us are not guarantees of future performance and the actual results may differ materially from those in our forward-looking statements. Some of the factors that could cause future results to differ materially from those expressed or implied by our forward-looking statements or from historical results, are described in the following section. Item 1A. Risk Factors You should carefully read the risks described below and other information in this Form 10-K in order to understand certain of the risks of our business. Overview of Risk Factors We have three business segments, water utility, electric utility and contracted services, each of which are subject to different risks as further discussed below. We are also subject to risks frequently encountered by businesses of our size. Regulated Water and Electric Utility Operations GSWCs and BVESIs revenues depend substantially on the rates and charges we are permitted to recover from our customers and the timing of that recovery as authorized by the CPUC. Decisions of the CPUC could also result in impairment charges and customer refunds, and delays in recovering costs in rates. Some of the factors impacting our ability to obtain rate recovery on a timely basis include opposition to rate increases arising out of increased costs for replacing aging infrastructure and increased costs associated with addressing climate change risks, such as drought and wildfires in California, costs incurred in connection with complying with water quality regulations, costs incurred in connection with complying with the COVID-19 pandemic, and costs incurred in connection with obtaining and complying with franchise agreements with local governmental agencies and costs of obtaining permits from local, state and federal governmental agencies. There may also be increased customer opposition to rate increases due to customer dissatisfaction with conservation rate structures and public safety power shutdowns. Our water and electric utility services are provided in California. As a result, our financial results are largely subject to political, water supply, labor, utility cost and regulatory risks, economic conditions, natural disasters (which may increase as a result of climate change), and other risks affecting California businesses. Our assets are also subject to condemnation in California. Contract Services Operations All of our utility privatization contract services are provided to the U.S. government pursuant to the terms of firm, fixed-price contracts subject to annual economic price adjustments. These contracts may be terminated or services suspended at any time for convenience of the government. We are subject to penalties for failure to conform or comply with U.S. government regulations and the terms of our contracts, and may be suspended or debarred for such failure to comply. The fees that we may charge are adjusted annually and in response to our requests for equitable adjustments. We have experienced delays in obtaining price and equitable adjustments, as well as delays in being paid by the U.S. government. We are also responsible for complying with water quality and wastewater quality regulations on military bases. We compete with other companies in bidding on providing utility services on military bases. We submit bids on new U.S. government contracts for military bases based on estimates of cost and potential profit. Our estimates and judgment are important, for in the event we overpay to obtain a contract, we could incur losses on it. Other Business Risks We may be subject to financial losses, penalties and other liabilities if we fail to operate and maintain safe work sites, equipment and facilities, including losses, damages, penalties and other liabilities arising from wildfires, other natural disasters and terrorist activities. We may not be able to recover all these losses from insurance or from ratepayers or may experience delays in obtaining recovery for these losses. We are also subject to other business risks typical of our business, including: Security risks, data protection and cyber-attacks that could disrupt our operations, increase our expenses, result in liabilities to third parties and damage to our reputation; Failure to attract, train, develop and transition key employees with the necessary skills to replace employees who are retiring or otherwise terminate employment or to fill new positions needed to respond to the increase in public utility and environmental regulations; Failure to make accurate estimates about financing and accounting matters, and in filing requests for rate increases with the CPUC or requests for price adjustments with the U.S. government or in bids on military privatization contracts; Our ability to finance the significant capital expenditures required by our businesses, which could be adversely impacted by general economic and market conditions; Changes in accounting, public utility, environmental and tax laws and regulations impacting our business; Our inability to comply with debt covenants in our debt agreements; and Final determination of our income tax liability by the federal and applicable state governments. As a holding company, AWR is dependent upon dividends from its subsidiaries to pay dividends to its shareholders. The ability of its subsidiaries to pay dividends is dependent upon compliance with state laws governing the payment of dividends and the terms of the debt agreements with the applicable subsidiary. Climate Change Climate change has resulted in increased frequency and duration of droughts, potential degradation of water quality, and changes in demand for services. More frequent and extended California drought conditions may cause increased stress on surface water supplies and groundwater basins, as well as allocations of water from the State Water Project and the Colorado River. Wholesale water suppliers may not have adequate supply during extended periods of drought, which may result in increases in prices for water delivered to us. In addition, GSWC could experience an increased use of reclaimed or recycled water by GSWC customers, in lieu of GSWC supplying potable water to these customers. Reclaimed water generally has lower tariff rates than potable water. Prolonged droughts may also result in state-ordered mandatory or voluntary conservation efforts by customers, changes in customer conservation patterns and imposition of new regulations impacting such things as landscaping and irrigation patterns. These drought conditions have contributed to increases in wildfires, which has resulted in new California legislation requiring electric utilities to adopt and implement wildfire safety and mitigation plans. BVESI is incurring increased capital expenditures related to the creation and implementation of these plans. We anticipate that the costs of capital improvements necessary to implement this program will continue to increase. BVESI is also required to implement a public safety power shut-off program during high wildfire threat conditions. Shut-offs can reduce BVESIs liquidity and decrease customer satisfaction. Abnormal weather patterns created by climate change can also impact electricity demand at BVESI. The demand for electricity at our electric segment is greatly affected by winter snow levels. An increase in winter snow levels reduces the use of snow making machines at ski resorts in the Big Bear area and, as a result, reduces our electric revenues. Likewise, unseasonably warm weather during a skiing season may result in temperatures too high for snow making conditions, which also reduces our liquidity. Furthermore, potential future legislation efforts to ban gas powered power plants as a response to climate change may require us to replace our current 8.4 MW natural gas powered generator before its useful life is completed. More extreme weather events which may result in flash flooding, mudslides and high winds which could damage our infrastructure and our customers and/or suppliers property as a result of climate change may increase our cost of maintaining our infrastructure, our ability to provide water or electric service and the demand of our services from customers whose property has been damaged. The cost of damage to our infrastructure may be somewhat mitigated if the CPUC permits us to establish a catastrophic emergency memorandum account enabling us to recover the costs incurred. Risks Associated with Regulated Public Utility and Contracted Services Operations Our businesses are heavily regulated and, as a result, decisions by regulatory agencies or the U.S. government can significantly affect our businesses GSWCs and BVESIs revenues depend substantially on the rates and fees they charge their customers and their ability to recover costs on a timely basis as authorized by the CPUC, including the ability to recover the costs of purchased water, groundwater assessments, electricity, natural gas, chemicals, water treatment, security at water facilities and preventative maintenance and emergency repairs. Any delays by the CPUC in granting rate relief to cover increased operating and capital costs at our public utilities or delays in obtaining approval of our requests at ASUS for economic price or equitable adjustments for contracted services from the U.S. government may adversely affect our financial performance. We may file for interim rates in California in situations where there may be delays in granting final rate relief during a general rate case proceeding. If the CPUC approves lower rates, the CPUC will require us to refund to customers the difference between the interim rates and the rates approved by the CPUC. Similarly, if the CPUC approves rates that are higher than the interim rates, the CPUC may authorize us to recover the difference between the interim rates and the final rates. Regulatory decisions affecting GSWC and/or BVESI may also impact prospective revenues and earnings, affect the timing of the recognition of revenues and expenses, may overturn past decisions used in determining our revenues and expenses, and could result in impairment charges and customer refunds. On August 27, 2020, the CPUC issued a final decision in the first phase of the CPUCs Order Instituting Rulemaking evaluating the low income ratepayer assistance and affordability objectives contained in the CPUCs 2010 Water Action Plan, which also addressed the continued use of the Water Revenue Adjustment Mechanism (WRAM) and the Modified Cost Balancing Account (MCBA) by California water utilities. Based on the final decision, any general rate case application filed by GSWC and the other California water utilities after the August 27, 2020 effective date of this decision, may not include a proposal to continue the use of the WRAM or MCBA, but may instead include a proposal to use a limited price adjustment mechanism (the Monterey-Style WRAM) and an incremental supply cost balancing account. As a result of the August 2020 decision, the discontinuation of the WRAM and MCBA for GSWC would be effective for years after 2024. However, on September 30, 2022, the governor of California signed Senate Bill (SB) 1469. Effective January 1, 2023, SB 1469 allows Class A water utilities, including GSWC, to continue requesting the use of the WRAM in their next general rate case. With the passage of SB 1469, GSWC will be able to request the continued use of the WRAM in its next general rate case to be filed in 2023 that will establish new rates for the years 2025 2027.

GSWCs request to continue using the WRAM in its next general rate case will be subject to CPUC approval. Management continually evaluates the anticipated recovery of regulatory assets, settlement of liabilities and revenues subject to refund and provides for allowances and reserves as deemed necessary. In the event that our assessment of the probability of recovery or settlement through the ratemaking process is incorrect, we will adjust the associated regulatory asset or liability to reflect the change in our assessment or any regulatory disallowances. A change in our evaluation of the probability over the recovery of regulatory assets including a future disallowance of previously granted regulatory mechanisms, or a regulatory disallowance of all or a portion of our costs could have a material adverse effect on our financial results. We are also, in some cases, required to estimate future expenses and, in others, we are required to incur the expense before recovering costs. As a result, our revenues and earnings may fluctuate depending on the accuracy of our estimates, the timing of our investments or expenses or other factors. If expenses increase significantly over a short period, we may experience delays in recovery of these expenses, the inability to recover carrying costs for these expenses, and increased risks of regulatory disallowances or write-offs. Changes in laws, regulations and policies of regulatory agencies can significantly affect our business Regulatory agencies may also change their rules and policies, which may adversely affect our profitability and cash flows. Changes in policies of the U.S. government may also adversely affect one or more of our Military Utility Privatization Subsidiaries. In certain circumstances, the U.S. government may be unwilling or unable to appropriate funds to pay costs mandated by changes in rules and policies of federal or state regulatory agencies. The U.S. government may disagree with the increases that we request and may delay approval of requests for equitable adjustment or economic price adjustments, which could adversely affect our anticipated rates of return at our contracted services business. We may also be subject to fines or penalties if a regulatory agency or the U.S. government determine that we have failed to comply with laws, regulations or orders applicable to our businesses, unless we successfully appeal such an adverse determination. Regulatory agencies may also disallow recovery of certain costs if they determine they may no longer be recovered in rates, or if audit findings determine that we have failed to comply with our policies and procedures for procurement or other practices. We may experience delays in receiving payments for services rendered in military bases due to delays in Congress appropriation bills or other factors affecting the available funds to pay contractors. Our liquidity and earnings may be adversely affected by maintenance costs Some of our infrastructure in California is aging. We have experienced leaks and mechanical problems in some of these older systems. In addition, infrastructure maintenance expenses are affected by labor and material costs and more stringent environmental regulations. Our electrical systems have also required upgrades due to aging and new wildfire safety and other compliance requirements. While we spend significant amounts on maintenance each year, these costs can increase substantially and unexpectedly. There could be an increase in infrastructure damage if California experiences more extreme weather events resulting in damage to our property. We include estimated increases in maintenance costs for future years in each water and electric general rate case filed by GSWC and BVESI, respectively, for possible recovery. To the extent that these estimates understate our actual costs, we may be unable to recover all maintenance costs in rates. Our assets at our regulated utilities are subject to condemnation Municipalities and other governmental subdivisions may, in certain circumstances, seek to acquire certain of our assets through eminent domain proceedings. It is generally our practice to contest these proceedings, which may be costly and may temporarily divert the attention of management from the operation of our business. If a municipality or other governmental subdivision succeeds in acquiring our assets, there is a risk that we will not receive adequate compensation for the assets taken or be able to recover all charges associated with the condemnation of such assets. In addition, we would no longer be entitled to any portion of the revenues generated from the use of such assets. Our costs of obtaining and complying with the terms of franchise agreements are increasing Cities and counties in which GSWC and BVESI operate have granted them franchises to construct, maintain and use pipes, wires and appurtenances in or along public streets and rights of way. The costs of obtaining, renewing and complying with the terms of these franchise agreements have been increasing as cities and counties attempt to regulate our operations within the boundaries of the city or unincorporated areas of the counties in which we operate. Our regulated utilities may also be required from time to time to relocate existing infrastructure in order to accommodate local infrastructure improvement projects. Cities and counties have also been imposing new fees on our operations, including pipeline abandonment fees and road-cut or other types of capital improvement fees. At the same time, there is increasing opposition from consumer groups to rate increases that may be necessary to compensate GSWC and BVESI for the increased costs of regulation by local governments. These trends may adversely affect our ability to recover in rates the costs of providing water and electric services and to efficiently manage capital expenditures and operating and maintenance expenses within CPUC-authorized levels. We have also experienced instances of increased costs and delays in obtaining permits that we need in order to install, maintain, repair, and replace some of our aging water and electric utility infrastructure and upgrades needed to comply with changes in laws and regulations or otherwise necessary to harden our infrastructure as a result of drought, wildfires and increases in the frequency and duration of more extreme weather events due to climate change. Adverse publicity and reputational risks can lead to increased regulatory oversight or sanctions As a utility company, we have a large customer base and are therefore, subject to public criticism regarding, among other things, the quality and reliability of our water and electricity services, and the accuracy, timeliness and format of bills that are provided to our customers for such services. Adverse publicity and negative customer sentiment may cause regulatory authorities, including the CPUC, and other governing bodies to view us unfavorably and cause us to be susceptible to increased oversight and more stringent regulations and economic requirements. Risks Associated with Health, Safety and Liability Matters The outbreak of COVID-19 and its impact on business and economic conditions could negatively affect our financial condition. The COVID-19 outbreak, the resulting pandemic, and the impact on the economy and financial markets could adversely affect the Companys financial condition. We have continued our operations given that water, wastewater, and electric utility services are deemed essential, and have implemented health and safety measures in accordance with the guidance provided by federal, state, and local health authorities and other government officials. Although the spread of COVID-19 has lessened, we may continue to experience impacts from the pandemic that include: an adverse impact on our business activities due to the ongoing shortage of skilled trade labor as well as engineering and professional staff; an increase in costs as a result of our emergency measures, delayed payments from our customers and uncollectible accounts as a result of the impact on our customers ability to pay bills; impact to our liquidity position and cost of and ability to access funds from financial institutions and capital markets; an adverse impact on the value of our pension and retirement assets; increased customer dissatisfaction due to an increase in customer wait times resulting from a rise in customer calls, and general anxiety due to personal circumstances arising from the pandemic; and supply chain disruptions and delays which impacts our ability and that of our subcontractors to build and maintain our infrastructure on a timely basis. The continued effects of the pandemic has impacted and may continue to impact supply chains with restrictions and limitations on business activities, impacts to labor shortages, capacity constraints, disruptions and delays. These issues may continue to place a strain on supply chains to sufficiently meet demand of the materials and supplies necessary to complete capital expenditure projects at our regulated utilities, or construction projects at our contracted services segment. While we may purchase materials and supplies upfront when appropriate, there can be no assurance that our efforts will prevent delays or disruptions to our capital investments or construction projects. Current supply chain challenges are driving price increases for materials commonly used for construction projects. Combined with rising labor costs, the current inflationary market is leading to an increase in total cost for our capital expenditure projects. Our regulated utilities update costs as part of general rate case proceedings, and ASUS updates prices annually through economic price adjustments. However, until we receive increased funding to offset higher costs, our liquidity may be negatively impacted. The CPUC has authorized GSWC and BVESI to track incremental costs, including bad debt expense in excess of what is included in their respective revenue requirements, incurred as a result of the pandemic in COVID-19 emergency-related memorandum accounts to be filed with the CPUC for future recovery. Emergency-type memorandum accounts are well-established cost recovery mechanisms authorized as a result of a state/federal declared emergency, and are therefore recognized as regulatory assets for future recovery. Also, as a result of the economic effects from the pandemic, there has been a trend of elevated workforce departures and competition for talent in the United States. While we expect to see continued competition for workforce talent, Registrant has not experienced the level of increases to workforce departure that many companies in the United States has been contending with during the year. Our liquidity and earnings may be adversely affected by wildfires It is possible that wildfires may occur more frequently, be of longer duration or impact larger areas as a result of drought-damaged plants and trees, lower humidity or higher winds that may occur as result of changing weather patterns. Our liquidity, earnings and operations may be materially adversely affected by wildfires. We may be required to (i) incur greater costs to relocate lines or increase our trimming of trees and other plants near our electric facilities to avoid wildfires, (ii) make significant additional capital expenditures to fund the projects in BVESIs wildfire and safety mitigation plans, and (iii) bear the costs of damages to property or injuries to the public if it is determined that our power lines or other electrical equipment was a cause of such damages or injuries. In addition, wildfires may result in reduced demand if structures are destroyed or unusable following a wildfire, and may adversely affect our ability to provide water or electric service in our service areas due to public safety power shutdowns or any of our water or electric utility infrastructure is damaged by a wildfire. Losses by insurance companies resulting from wildfires in California have caused insurance coverage for wildfire risks to become more expensive and coverage could become unavailable on reasonable terms, and our insurance may be inadequate to recover all our losses incurred in a wildfire. We might not be allowed to recover in our rates any increased costs of wildfire insurance or the costs of any uninsured wildfire losses. Electric utilities in California are authorized to shut off power for public safety reasons, such as during periods of extreme fire hazard, if the utility reasonably believes that there is an imminent and significant risk that strong winds may topple power lines or cause vegetation to come into contact with power lines leading to increased risk of fire. Shut-offs can reduce BVESIs liquidity and decrease customer satisfaction. These shut-offs can also adversely affect GSWCs water utility operations if the electric utilities that provide electric service to GSWCs water operations shut off power lines that deliver electricity to GSWCs water plant and equipment, thereby adversely affecting its ability to provide water service to its customers. We may be held strictly liable for damages to property caused by our equipment even if we are not negligent Utilities in California may be held strictly liable for damages caused by their property, such as mains, fire hydrants, power lines and other equipment, even though they were not negligent in the operation and maintenance of that property, under a doctrine known as inverse condemnation. Our liquidity, earnings and operations may be adversely affected if we are unable to recover the costs of paying claims for damages caused by the non-negligent operation and maintenance of our property from customers or through insurance. We may be subject to financial losses, penalties and other liabilities if we fail to maintain safe work sites, equipment or facilities Our safety record is critical to our reputation. We maintain health and safety standards to protect our employees, customers, vendors and the public. Although we aim to comply with such health and safety standards, it is unlikely that we will be able to avoid all accidents or other events resulting in damage to property or the public. Our business sites, including construction and maintenance sites, often put our employees and others in close proximity with large pieces of equipment, moving vehicles, pressurized water, chemicals and other regulated materials. On many sites, we are responsible for safety and, accordingly, must implement safety procedures. If we fail in any respect to implement such procedures or if the procedures we implement are ineffective or are not followed by our employees or others, our employees and others may be injured or die. Unsafe work sites also have the potential to increase our operating costs. Any of the foregoing could result in financial losses, which could have a material adverse impact on our business, financial condition, and results of operations. Our operations involve the handling and storage of hazardous chemicals that, if improperly handled, stored or disposed of, could subject us to penalties or other liabilities. We are also subject to regulations dealing with occupational health and safety. Although we maintain functional employee groups whose primary purpose is to ensure that we implement effective health, safety, and environmental work procedures throughout our organization, including construction sites and maintenance sites, a failure to comply with such regulations in any respect could subject us to liability. The generation, transmission and distribution of electricity are dangerous and involve inherent risks of damage to private property and injury to employees and the general public Electricity is dangerous for employees and the general public should they come in contact with electrical current or equipment, including through downed power lines, sparking during high-wind events or equipment malfunctions. Injuries and property damage caused by such events may subject BVESI to significant liabilities that may not be covered or fully covered by insurance. Additionally, the CPUC has delegated to its staff the authority to issue citations, which carry a fine of $50,000 per-violation per day, to electric utilities subject to its jurisdiction for violations of safety rules found in statutes, regulations, and the General Orders of the CPUC. We may sustain losses that exceed or are excluded from our insurance coverage or for which we are not insured We are, from time to time, parties to legal or regulatory proceedings. These proceedings may pertain to regulatory investigations, employment matters or other disputes. Management periodically reviews its assessment of the probable outcome of these proceedings, the costs and expenses reasonably expected to be incurred, and the availability and extent of insurance coverage. On the basis of this review, management establishes reserves for such matters. We may, however, from time to time be required to pay fines, penalties or damages that exceed our insurance coverage and/or reserves if our estimate of the probable outcome of such proceedings proves to be inaccurate. We maintain insurance coverage as part of our overall legal and risk management strategy to minimize our potential liabilities. Generally, our insurance policies cover property, workers compensation, general liability, automobile liability, and other risks. Insurance coverage may not cover certain claims involving punitive damages. Each policy includes deductibles or self-insured retentions and policy limits for covered claims. Our insurance policies also contain exclusions and other limitations that may not cover our potential liabilities. Furthermore, due to insurance market conditions resulting in tighter underwriting and increased premiums along with reductions in capacity, we have experienced increased costs and difficulties in obtaining certain insurance coverages, particularly along the general liability, umbrella and cyber insurance lines. We may experience further increased insurance costs and/or coverage reductions in future years. As a result, we may sustain losses that exceed or that are excluded from our insurance coverage or for which we are not insured. Uninsured losses and increases in the cost of insurance may not be recoverable or fully recoverable in customer rates. A loss which is not insured or not fully insured or cannot be recovered in customer rates could materially affect our financial condition and results of operations. We operate in areas subject to natural disasters We operate in areas that are prone to earthquakes, fires, mudslides, hurricanes, tornadoes, high winds, flooding or other natural disasters. While we maintain insurance policies to help reduce our financial exposure, a significant seismic event in southern California, where our regulated water and electric operations are concentrated, wildfires or other natural disasters in any of the areas that we serve could adversely impact our ability to deliver water and electricity or provide wastewater service, and adversely affect our costs of operations. With respect to GSWC and BVESI, the CPUC has historically allowed utilities to establish a catastrophic emergency memorandum account (CEMA) to potentially recover such incremental costs not covered in rates. With respect to the Military Utility Privatization Subsidiaries, costs associated with responding to natural disasters have been recoverable through requests for equitable adjustment. Our operations may be the target of terrorist activities Terrorists could seek to disrupt service to our customers by targeting our assets. We have invested in additional security for facilities throughout our regulated service areas to mitigate the risks of terrorist activities. We also may be prevented from providing water and/or wastewater services at the military bases we serve in times of military crisis affecting these bases. Water Quality Regulatory Risks Our costs involved in maintaining water quality and complying with environmental regulation have increased and are expected to continue to increase Our capital and operating costs at GSWC may increase substantially as a result of increases in environmental regulation arising from increases in the cost of upgrading and building new water treatment plants, disposing of residuals from our water treatment plants, handling and storing hazardous chemicals, compliance-monitoring activities and securing alternative supplies when necessary. GSWC may be able to recover these costs from customers through the ratemaking process. We may also be able to recover these costs from certain third parties under settlement and contractual arrangements. Our capital and operating costs may also increase as a result of changes in laboratory detection capabilities and drinking water notification and response levels for certain substances, such as perfluoroalkyl substances (PFAS) used to make certain fabrics and other materials, certain fire suppression agents and used in various industrial processes. Our operating costs may increase as a result of groundwater contamination Our operations can be impacted by groundwater contamination in certain service territories. Historically, we have taken a number of steps to address contamination, including the removal of wells from service, decreasing the amount of groundwater pumped from wells in order to facilitate remediation of plumes of contaminated water, constructing water treatment facilities and securing alternative sources of supply from other areas not affected by the contamination. In emergency situations, we have supplied our customers with bottled water until the emergency situation has been resolved. Our ability to recover these types of costs depends upon a variety of factors, including approval of rate increases, the willingness of potentially responsible parties to settle litigation and otherwise address the contamination, and the extent and magnitude of the contamination. We may recover costs from certain third parties that may be responsible, or potentially responsible, for groundwater contamination. However, we often experience delays in obtaining recovery of these costs and incur additional costs associated with seeking recovery from responsible or potentially responsible parties, which may adversely impact our liquidity. In some events, we may be unable to recover all of these costs from third parties due to the inability to identify the potentially responsible parties, the lack of financial resources of responsible parties or the high litigation costs associated with obtaining recovery from responsible or potentially responsible parties. We can give no assurance regarding the adequacy of any such recovery to offset the costs associated with contamination or the cost of recovery of any legal costs. To date, the CPUC has permitted us to establish memorandum accounts for potential recovery of these types of costs when they have arisen. Management believes that rate recovery, proper insurance coverage and reserves are in place to appropriately manage these types of contamination issues. However, such issues, if ultimately resolved unfavorably to us, could, in the aggregate, have a material adverse effect on our results of operations and financial condition. Water Supply Risks The adequacy of our water supplies depends upon weather and a variety of other uncontrollable factors The adequacy of our water supplies varies from year to year depending upon a variety of factors, including: rainfall, basin replenishment, flood control, snow pack levels in California and the West, reservoir levels and availability of reservoir storage; availability of Colorado River water and imported water from the State Water Project; the amount of usable water stored in reservoirs and groundwater basins; the amount of water used by our customers and others; water quality; legal limitations on production, diversion, storage, conveyance and use; and climate change. More frequent and extended California drought conditions and changes in weather patterns cause increased stress on surface water supplies and groundwater basins. In addition, low or no allocations of water from the State Water Project and court-ordered pumping restrictions on water obtained from the Sacramento-San Joaquin Delta decrease or eliminate the amount of water that the Metropolitan Water District of Southern California (MWD) and other state water contractors are able to import from northern California. We have implemented tiered rates and other practices, as appropriate, in order to encourage water conservation. We have also implemented programs to assist customers in complying with water usage reductions. Over the long term, we are acting to secure additional supplies, which may include supplies from desalination and increased use of reclaimed water, where appropriate and feasible. We cannot predict the extent to which these efforts to reduce stress on our water supplies will be successful or sustainable, or the extent to which these efforts will enable us to continue to satisfy all of the water needs of our customers. Water shortages at GSWC may: adversely affect our supply mix, for instance, by causing increased reliance upon more expensive water sources; adversely affect our operating costs, for instance, by increasing the cost of producing water from more highly contaminated aquifers or requiring us to transport water over longer distances, truck water to water systems or adopt other emergency measures to enable us to continue to provide water service to our customers; result in an increase in our capital expenditures over the long term, for example, by requiring future construction of pipelines to connect to alternative sources of supply, new wells to replace those that are no longer in service or are otherwise inadequate to meet the needs of our customers, and other facilities to conserve or reclaim water; adversely affect the volume of water sold as a result of such factors as mandatory or voluntary conservation efforts by customers, changes in customer conservation patterns, recycling of water by customers and imposition of new regulations impacting such things as landscaping and irrigation patterns; adversely affect aesthetic water quality if we are unable to flush our water systems as frequently due to water shortages or drought restrictions; and result in customer dissatisfaction and harm to our reputation if water service is reduced, interrupted or otherwise adversely affected as a result of drought, water contamination or other causes. Our liquidity may be adversely affected by changes in water supply costs We obtain our water supplies for GSWC from a variety of sources, which vary among our water systems. Certain systems obtain all of their supply from water that is pumped from aquifers within our service areas; some systems purchase all of their supply from wholesale suppliers; some systems obtain their supply from treating surface water sources; and other systems obtain their supply from a combination of wells, surface water sources and/or wholesale suppliers. The cost of obtaining these supplies varies, and overall costs can be impacted as use within a system varies from time to time. As a result, our cost of providing, distributing and treating water for our customers use can vary significantly. Furthermore, imported water wholesalers, such as MWD, may not always have an adequate supply of water to sell to us. Wholesale water suppliers may increase their prices for water delivered to us based on factors that affect their operating costs. Purchased water rate increases are beyond our control. GSWC has implemented a modified supply cost balancing account, the MCBA, to track and recover costs from supply mix changes and rate changes by wholesale suppliers, as authorized by the CPUC. However, cash flows from operations can be significantly affected since much of the balance we recognize in the MCBA is collected from or refunded to customers primarily through surcharges or surcredits, respectively, generally over twelve- to twenty-four-months. Our liquidity and earnings may be adversely affected by our conservation efforts Our water utility business is heavily dependent upon revenue generated from rates charged to our customers based on the volume of water used. The rates we charge for water are regulated by the CPUC and may not be adequately adjusted to reflect changes in demand. Declining usage also negatively impacts our long-term operating revenues if we are unable to secure rate increases or if growth in the customer base does not occur to the extent necessary to offset per-customer usage decline. Conservation by all customer classes at GSWC is a top priority. However, customer conservation will result in lower volumes of water sold. We may experience a decline in per-customer water usage due to factors such as: conservation efforts to reduce costs; drought conditions resulting in additional water conservation; the use of more efficient household fixtures and appliances by customers to save water; voluntary or mandatory changes in landscaping and irrigation patterns; recycling of water by our customers; and mandated water-use restrictions. These types of changes may result in permanent decreases in demand even if our water supplies are sufficient to meet higher levels of demand after a drought ends. In addition, governmental restrictions on water usage during drought conditions may result in a decreased demand for water, even if our sources of supply are sufficient to serve our customers during such drought conditions. We implemented the CPUC-approved WRAM at GSWC, which has the effect of stabilizing revenues at the adopted level thereby reducing the potential adverse earnings impact of our customers conservation efforts. However, cash flows from operations can be significantly affected since much of the balance we recognize in the WRAM account is collected from or refunded to customers generally over twelve-, eighteen- or twenty-four-month periods. Electric Segment Operations Risks Our electric segment operates in a high wildfire risk area BVESI is required to adopt and implement a wildfire safety and mitigation plan that is submitted periodically to, and subject to the approval of, the CPUC. The recovery of costs incurred to implement this plan are not approved by the CPUC at the time of its approval of the wildfire mitigation plan, but will only be approved by the CPUC in a subsequent general rate case. We anticipate that the costs of capital improvements necessary to implement this program will increase substantially. BVESI is also required to implement a public safety power shut-off program during high wildfire threat conditions. The CPUC may assess penalties if BVESI shuts-down power to its customers and the CPUC determines that the shutdown was not reasonably necessary in the circumstances. BVESI has also obtained a safety certificate, which must be renewed annually by the CPUC. Even with an approved safety certificate, BVESI could be found liable for deaths, injuries and property damage if BVESIs electric equipment is found to have caused a catastrophic wildfire. BVESI may not be able to recover the costs of all liabilities from such a wildfire from insurance or from ratepayers. Our liquidity may be adversely affected by increases in electricity and natural gas prices in California We purchase most of the electric energy sold to customers in our electric customer service area from others under purchased power contracts. In addition to purchased power contracts, we purchase additional energy from the spot market to meet peak demand and following the expiration of purchased power contracts if there are delays in obtaining CPUC authorization of new purchase power contracts. We may sell surplus power to the spot market during times of reduced energy demand. As a result, our cash flows may be affected by increases in spot market prices of electricity purchased and decreases in spot market prices for electricity sold. However, BVESI has implemented a CPUC-approved supply-cost balancing account to mitigate the impact to earnings from fluctuations in supply costs. Unexpected generator downtime at our 8.4 megawatt natural-gas-fueled generator or a failure to perform by any of the counterparties to our electric and natural gas purchase contracts could further increase our exposure to fluctuating natural gas and electricity prices. Changes in electricity prices also affect the unrealized gains and losses on our block forward purchased power contracts that qualify as derivative instruments since we adjust the asset or liability on these contracts to reflect the fair market value of the contracts at the end of each month. The CPUC has authorized us to establish a memorandum account to track the changes in the fair market value of our purchased power contracts. As a result, unrealized gains and losses on these types of purchased power contracts do not impact earnings. We may not be able to procure sufficient renewable energy resources to comply with CPUC rules We are required to procure a portion of our electricity for BVESI from renewable energy resources to meet the CPUCs renewable procurement requirements. We have an agreement with a third party to purchase renewable energy credits, which enables us to meet these requirements through 2023. In the event that the third party fails to perform in accordance with the terms of the agreement, we may not be able to obtain sufficient resources to meet the renewable procurement requirements. We may be subject to fines and penalties by the CPUC if it determines that we are not in compliance with the renewable resource procurement rules. Utility Privatization Contract Risks Our contracts for servicing military bases create certain risks that are different from our public utility operations We have entered into contracts to provide water and/or wastewater services at military bases pursuant to an initial 50-year firm, fixed-priced contract and additional firm, fixed-price contracts, subject to termination, in whole or in part, for the convenience of the U.S. government. In addition, the U.S. government may stop work under the terms of one or more of the contracts, delay performance of our obligations under the contracts or modify the contracts at its convenience. Our contract pricing is based on a number of assumptions, including assumptions about the condition and amount of infrastructure at the military bases, prices and availability of labor, equipment and materials. We may be unable to recover all costs if any of these assumptions are inaccurate or if all costs incurred in connection with performing the work were not considered. Our contracts are also subject to annual economic price adjustments or other changes permitted by the terms of the contracts. Prices are also subject to equitable adjustment based upon changes in circumstances, laws or regulations and service-requirement changes to the extent provided in each of the contracts. We are required to record all costs under these types of contracts as they are incurred. As a result, we may record losses associated with unanticipated conditions that result in higher than estimated costs, higher than anticipated infrastructure levels, and required emergency work at the time such expenses occur. We recognize additional revenue for such work as, and to the extent that, our economic price adjustments and/or requests for equitable adjustments are approved. Delays in obtaining approval of economic price adjustments and/or equitable adjustments can negatively impact our results of operations and cash flows. Certain payments under these contracts are subject to appropriations by Congress. We may experience delays in receiving payment or delays in price adjustments due to canceled or delayed appropriations specific to our projects, reductions in government spending for the military generally or military-base operations specifically or other delays in Congress approving appropriations. Appropriations and the timing of payment may be influenced by, among other things, the state of the economy, competing political priorities, budget constraints, the timing and amount of tax receipts, government shutdowns and the overall level of government expenditures. Our contracts for the construction of infrastructure improvements on military bases create risks that are different from those of our public utility operations and maintenance activities We have entered into contract modifications with the U.S. government and agreements with third parties for the construction of new water and/or wastewater infrastructure at the military bases on which we operate. Most of these contracts are firm fixed-price contracts. Under firm fixed-price contracts, we will benefit from cost savings, but are generally unable (except for changes in scope or circumstances approved by the U.S. government or third party) to recover any cost overruns to the approved contract price. Under most circumstances, the U.S. government or third party has approved increased-cost change orders due to changes in scope of work performed. We generally recognize contract revenues from these types of contracts over time using input methods to measure progress towards satisfying a performance obligation. The measurement of performance over time is based on cost incurred relative to total estimated costs, or the physical completion of the construction projects. The earnings or losses recognized on individual contracts are based on periodic estimates of contract revenues, costs and profitability as these construction projects progress. We establish prices for these types of firm fixed-price contracts and the overall 50-year contract taken as a whole, based, in part, on cost estimates that are subject to a number of assumptions, including assumptions regarding future economic conditions. If these estimates prove inaccurate or circumstances change, cost overruns could have a material adverse effect on our contracted business operations and results of operations. We may be adversely affected by disputes with the U.S. government regarding our performance of contracted services on military bases Entering into contracts with the U.S. government subjects us to a number of operational and compliance risks over our performance of contracted services on military bases. We are periodically audited or reviewed by the Defense Contract Auditing Agency (DCAA), the Defense Contract Management Agency (DCMA), the Department of Labor (DOL), the Defense Logistics Agency Energy (DLAE), and/or the Department of Justice (DOJ) for compliance with federal acquisition regulations, cost-accounting standards and other laws, regulations and standards that are not applicable to the operations of GSWC or BVESI. During the course of these audits/reviews, the U.S. government may question our incurred project costs or the manner in which we have accounted for such costs and recommend to our U.S. government administrative contracting officer that such costs be disallowed. If there is a dispute with the U.S. government regarding performance under these contracts or the amounts owed to us, the U.S. government may delay, reject or withhold payment, delay price adjustments or assert its right to offset damages against amounts owed to us. If we are unable to collect amounts owed to us on a timely basis or the U.S. government asserts its offset rights, profits and cash flows could be adversely affected. Moreover, we are subject to potential government investigations of our business practices and compliance with government procurement statutes and security regulations. If we are charged with wrongdoing as a result of an investigation, or if we fail to comply with the terms of one or more of our U.S. government contracts, other agreements with the U.S. government or U.S. government statutes and regulations, our existing contracts could be terminated or we could be suspended or barred from future U.S. government contracts for a period of time, and be subject to possible damages, fines and penalties as well as damage to our reputation in the water and wastewater industry, which could have a material adverse effect on our results of operations and cash flows. We depend, to some extent, upon subcontractors to assist us in the performance of contracted services on military bases We rely, to some extent, on subcontractors to assist us in the operation and maintenance of the water and wastewater systems at military bases. The failure of any of these subcontractors to perform services for us in accordance with the terms of our contracts with the U.S. government could result in the termination of our contract to provide water and/or wastewater services at the affected base(s), and/or a loss of revenues, or increases in costs, to correct a subcontractors performance failures. We are also required to make a good faith effort to achieve our small business subcontracting plan goals pursuant to U.S. government regulations. If we fail to use good faith efforts to meet these goals, the U.S. government may assess damages against us at the end of the contract. The U.S. government has the right to offset claimed damages against any amounts owed to us. We also rely on third-party manufacturers, as well as third-party subcontractors, to complete our construction projects. To the extent that we cannot engage subcontractors or acquire equipment or materials, our ability to complete a project in a timely fashion or at a profit may be impaired. If the amount of costs we incur for these projects exceeds the amount we have estimated in our bids, we could experience reduced profits or losses in the performance of these contracts. In addition, if a subcontractor or manufacturer is unable to deliver its services, equipment or materials according to the negotiated terms for any reason, including the deterioration of its financial condition, we may be required to purchase the services, equipment or materials from another source at a higher price. This may reduce the profit to be realized or result in a loss on a project for which the services, equipment or materials were needed. If subcontractors fail to perform services to be provided to us or fail to provide us with the proper equipment or materials, we may be penalized for their failure to perform; however, our contracts with subcontractors include certain protective provisions, which may include the assessment of liquidated damages. We also mitigate these risks by requiring our subcontractors, as appropriate, to obtain performance bonds and to compensate us for any penalties we may be required to pay as a result of their failure to perform. We may not be fully reimbursed for all of our construction costs or may only receive payment on a delayed basis Unlike GSWC and BVESI, who recover their capital investments from customers over the life of the assets through annual depreciation and earn a return on such investments through the ratemaking process, ASUS is reimbursed for the cost of ongoing renewal and replacement construction projects plus a profit through the collection of a monthly cash stream under each of the contracts with the U.S. government. ASUS also receives funding from the U.S. government for initial and other new construction projects at the military bases it serves that, in many cases, are outside the scope of contracts with the U.S. government and are granted through firm-fixed contract modifications. Our Military Utility Privatization Subsidiaries expect to continue incurring significant construction costs. Reimbursement by the U.S government for these construction costs may not be fully reimbursable if the costs incurred are greater than the amounts estimated and approved by the U.S. government, or payments may be delayed awaiting government funding and processing, which could significantly affect our cash flows from operations. Other Contracted Services Segment Risks Risks associated with wastewater systems are different from those of our water distribution operations The wastewater-collection-system operations of our ASUS subsidiaries providing wastewater services on military bases are subject to substantial regulation and involve significant environmental risks. If collection, treatment or disposal systems fail, overflow or do not operate properly, untreated wastewater or other contaminants could spill onto nearby properties or into nearby streams and rivers, causing damage to persons or property, injury to aquatic life and economic damages. The cost of addressing such damages may not be recoverable. This risk is most acute during periods of substantial rainfall or flooding, which are common causes of sewer overflows and system failures. These risks may be increased as a result of an increase in the duration and frequency of storms due to climate change. Liabilities resulting from such damage could adversely and materially affect our business, results of operations and financial condition. In the event that we are deemed liable for any damage caused by overflows, our losses may not be recoverable under our contracts with the U.S. government or covered by insurance policies. We may also find it difficult to secure insurance for this business in the future at acceptable rates. We may have responsibility for water quality at the military bases we serve While it is the responsibility of the U.S. government to provide the source of water supply to meet the Military Utility Privatization Subsidiaries water distribution system requirements under their contracts with the U.S. government, the Military Utility Privatization Subsidiaries, as the water system permit holders for most of the bases they serve, are responsible for ensuring the continued compliance of the provided source of supply with all federal, state and local regulations. We believe, however, that the terms of the contracts between the Military Utility Privatization Subsidiaries and the U.S. government provide the opportunity for us to recover costs incurred in the treatment or remediation of any quality issue that arises from the source of water supply. Our earnings may be affected, to some extent, by weather during different seasons Seasonal weather conditions, such as hurricanes, heavy rainfall or significant winter storms, occasionally cause temporary office closures and/or result in temporary halts to construction activity at military bases. To the extent that our construction activities are impeded by these events, we will experience a delay in recognizing revenues from these construction projects. We continue to incur costs associated with the expansion of our contract activities We continue to incur additional costs in connection with the expansion of our contract operations associated with the preparation of bids for new contract operations on prospective and existing military bases. Our ability to recover these costs and to earn a profit on our contract operations will depend upon the extent to which we are successful in obtaining new contracts and recovering these costs and other costs from new contract revenues. We face intense competition for new military privatization contracts An important part of our growth strategy is the expansion of our contracted services business through new contract awards to serve additional military bases for the U.S. government. ASUS competes with other investor-owned utilities, municipalities, and other entities for these contracts. Additionally, the U.S. government periodically reviews the cost and overall effectiveness of the military privatization program. Should these reviews prompt a decision to curtail or eliminate the issuance of solicitations for future military privatization contract awards, the potential for growth in this segment could be negatively impacted. Information Technology Risk Factors We must successfully maintain and/or upgrade our information technology systems as we are increasingly dependent on the continuous and reliable operation of these systems We rely on various information technology systems to manage our operations. Such systems require periodic modifications, upgrades and/or replacement, which subject us to inherent costs and risks, including potential disruption of our internal control structure, substantial capital expenditures, additional administrative and operating expenses, retention of sufficiently skilled personnel to implement and operate the new systems, and other risks and costs of delays or difficulties in transitioning to new systems or of integrating new systems into our current systems. In addition, the difficulties with implementing new technology systems may cause disruptions in our business operations and have an adverse effect on our business and operations, if not anticipated and appropriately mitigated. We rely on our computer, information and communications technology systems in connection with the operation of our business, especially with respect to customer service and billing, accounting and the monitoring and operation of our treatment, storage and pumping facilities. Our computer and communications systems and operations could be damaged or interrupted by weather, natural disasters, telecommunications failures, cyberattacks or acts of war or terrorism or similar events or disruptions. Any of these or other events could cause system interruption, delays and loss of critical data, or delay or prevent operations and adversely affect our financial results and could result in liabilities not covered by insurance or recoverable in rates for misappropriation of assets or sensitive information, corruption of data and the impact of operational disruptions on our customers. Security risks, data protection breaches and cyberattacks could disrupt our internal operations, and any such disruption could increase our expenses, damage our reputation and adversely affect our stock price There have been an increasing number of cyberattacks on companies around the world, which have caused operational failures or compromised sensitive corporate or customer data. These attacks have occurred over the internet, through malware, viruses or attachments to e-mails, or through persons inside the organization or with access to systems inside the organization. Although we do not believe that our systems are at a materially greater risk of cyber security attacks than other similar organizations, our information technology systems remain at risk to damage or interruption from: supply chain attacks; ransomware; malware; hacking; and denial of service actions. We have implemented security measures and will continue to devote significant resources to improve our security posture to address any security vulnerabilities in an effort to prevent cyberattacks. Despite our efforts, due to the evolving nature of cyberattacks and vulnerabilities, we cannot be assured that a cyberattack will not cause water, wastewater or electric system problems, disrupt service to our customers, compromise important data or systems or result in unintended release of customer or employee information. Moreover, if a security breach affects our systems or results in the unauthorized release of sensitive data, our reputation could be materially damaged. We may not discover any security breach and loss of information for a significant period of time after the security breach. We could also be exposed to a risk of loss or litigation and possible liability. In addition, pursuant to U.S. government regulations regarding cybersecurity of government contractors, we might be subject to fines, penalties or other actions, including debarment, with respect to current contracts or with respect to future contract opportunities. We maintain cybersecurity insurance to provide coverage for a portion of the losses and damages that may result from a security breach, but such insurance is subject to a number of exclusions and may not cover the total loss caused by a breach. Other costs associated with cyber events may not be covered by insurance or recoverable in rates. The market for cybersecurity insurance continues to evolve and may affect the future availability of cyber insurance at reasonable rates. In addition, we must comply with privacy rights regulations such as The California Consumer Privacy Act (CCPA), a state statute that became effective January 1, 2020, which enhances the privacy rights and consumer protections for California residents. Among other things, the CCPA establishes statutory damages for victims of data security breaches, and provides additional rights for consumers to obtain their data from any business that has their personally identifying information. Any actual or perceived failure to comply with the CCPA could lead to investigations, claims, and proceedings by governmental entities and private parties, damages for breach, and other significant costs, penalties, and other liabilities, as well as harm to our reputation. Human Capital Management and Supply Risks Failure to attract, retain, train, motivate, develop and transition key employees could adversely affect our business In order to be successful, we must attract, retain, train, motivate, and develop key employees, including those in managerial, operational, financial, regulatory, business-development and information-technology support positions. Our regulated business and contracted services operations are complex. Attracting and retaining high quality staff allows us to minimize the cost of providing quality service. In order to attract and retain key employees in a competitive marketplace, we must provide a competitive compensation package and be able to effectively recruit qualified candidates. This is especially challenging for us since approximately 30% of our employees will be eligible to retire in the next five years. The failure to successfully hire key employees or the loss of a material number of key employees could have a significant impact on the quality of our operations in the short term. Further, changes in our management team may be disruptive to our business, and any failure to successfully transition key new hires or promoted employees could adversely affect our business and results of operations. Failure of our employees to maintain required certifications and licenses or to complete required compliance training could adversely impact our ability to operate and maintain our utility systems and provide services to our customers Many of our employees must have specialized certifications and licenses in order to perform their duties and periodically complete required compliance training. Our business could be adversely affected if our employees do not maintain their certifications and licenses or we are unable to attract employees with the necessary certifications and licenses. Other Business Risk Factors The accuracy of our judgments and estimates about financial and accounting matters will impact our operating results and financial condition The quality and accuracy of estimates and judgments used have an impact on our operating results and financial condition. If our estimates are not accurate, we will be required to make an adjustment in a future period. We make certain estimates and judgments in preparing our financial statements regarding, among others: timing of recovering WRAM and MCBA regulatory assets; amounts to set aside for uncollectible accounts receivable, inventory obsolescence and uninsured losses; our legal exposure and the appropriate accrual for claims, including general liability and workers compensation claims; future costs and assumptions for pensions and other post-retirement benefits; regulatory recovery of deferred items; and possible tax uncertainties. Market conditions and demographic changes may adversely impact the value of our benefit plan assets and liabilities Market factors can affect assumptions we use in determining funding requirements with respect to our pension and other post-retirement benefit plans. For example, a relatively modest change in our assumptions regarding discount rates can materially affect our calculation of funding requirements. To the extent that market data compels us to reduce the discount rate used in our assumptions, our benefit obligations could materially increase, which could adversely affect our financial position and cash flows. Further, changes in demographics, such as increases in life expectancy assumptions may also increase the funding requirements of our obligations related to the pension and other post-retirement benefit plans. Market conditions also affect the values of the assets that are held in trusts to satisfy significant future obligations under our pension and other post-retirement benefit plans. These assets are subject to market fluctuations, which may cause investment returns to fall below our projected rates of return. A decline in the market value of our pension and other post-retirement benefit plan assets will increase the funding requirements under these plans if future returns on these assets are insufficient to offset the decline in value. Future increases in pension and other post-retirement costs as a result of the reduced value of plan assets may not be fully recoverable in rates, and our results of operations and financial position could be negatively affected. These risks are mitigated to some extent by the two-way pension balancing accounts authorized by the CPUC, which permits us to track differences between forecasted annual pension expense adopted in water and electric rates and actual pension expenses for future recovery or refund to customers. Our business requires significant capital expenditures and our inability to access the capital or financial markets could affect our ability to meet our liquidity needs and long-term commitments, which could adversely impact our operations and financial results The utility business is capital intensive. We spend significant sums of money for additions to, or replacement of, our property, plant and equipment at our water and electric regulated utilities. We obtain funds for these capital projects from operations, contributions by developers and others, and refundable advances from developers (which are repaid over a period of time). We also periodically borrow money or issue equity for these purposes. In addition, we have revolving credit facilities that are partially used for these purposes. We cannot provide assurance that these sources will continue to be adequate or that the cost of funds will remain at levels permitting us to earn a reasonable rate of return. As our capital investment program continues to increase, coupled with the elimination of bonus depreciation for regulated utilities due to tax reform, we will need access to external financing more often, which increases our exposure to market conditions. In addition to cash flow from operations, we rely primarily on our credit facilities and long-term private placement notes to satisfy our liquidity needs. Changes in market conditions, including events beyond our control such as recent increases to interest rates, could limit our ability to access capital on terms favorable to us or at all, including credit facilities with the borrowing capacities needed as well as issuing long-term debt. As a result, the amount of capital available may not be sufficient to meet all our liquidity needs at a reasonable cost at all of our subsidiaries. The price of our Common Shares may be volatile and may be affected by market conditions beyond our control The trading price of our Common Shares may fluctuate in the future because of the volatility of the stock market and a variety of other factors, many of which are beyond our control. Factors that could cause fluctuations in the trading price of our Common Shares include: changes in interest rates; regulatory developments; general economic conditions and trends; price and volume fluctuations in the overall stock market; actual or anticipated changes or fluctuations in our results of operations; actual or anticipated changes in the expectations of investors or securities analysts; actual or anticipated developments in other utilities businesses or the competitive landscape generally; litigation involving us or our industry; major catastrophic events, or sales of large blocks of our stock. Payment of our debt may be accelerated if we fail to comply with restrictive covenants in our debt agreements Our failure to comply with restrictive covenants in our debt agreements could result in an event of default. If the default is not cured or waived, we may be required to repay or refinance the debt before it becomes due. Even if we are able to obtain waivers from our creditors, we may only be able to do so on unfavorable terms. AWR is a holding company that depends on cash flow from its subsidiaries to meet its financial obligations and to pay dividends on its Common Shares As a holding company, our subsidiaries conduct substantially all operations and our only significant assets are investments in our subsidiaries. This means that we are dependent on distributions of funds from our subsidiaries to meet our debt service obligations and to pay dividends on our Common Shares. Our subsidiaries are separate and distinct legal entities and generally have no obligation to pay any amounts due on AWRs credit facility. Our subsidiaries only pay dividends if and when declared by the respective subsidiary board. Moreover, GSWC and BVESI are obligated to give first priority to their own capital requirements and to maintain capital structures consistent with those determined to be reasonable by the CPUC in its most recent decisions on capital structure for both GSWC and BVESI in order for customers to not be adversely affected by the holding company structure. Furthermore, our right to receive cash or other assets in the unlikely event of liquidation or reorganization of any of our subsidiaries is generally subject to the prior claims of creditors of that subsidiary. If we are unable to obtain funds from a subsidiary in a timely manner, we may be unable to meet our financial obligations, make additional investments or pay dividends. The final determination of our income tax liability may be materially different from our income tax provision Significant judgment is required in determining our provision for income taxes. Our calculation of the provision for income taxes is subject to our interpretation of applicable tax laws in the jurisdictions in which we file. In addition, our income tax returns are subject to periodic examination by the Internal Revenue Service and other taxing authorities. Although we believe our income tax estimates are appropriate, there is no assurance that the final determination of our current taxes payable will not be materially different, either higher or lower, from the amounts reflected in our financial statements. In the event we are assessed additional income taxes, our financial condition and cash flows could be adversely affected. Our operations are geographically concentrated in California Although we operate water and wastewater facilities in a number of states under our contracted services business, our regulated water and electric operations are concentrated in California, particularly Southern California. As a result, our financial results are largely subject to political, water supply, labor, utility cost and regulatory risks, economic conditions, natural disasters (which may increase as a result of climate change) and other risks affecting California. Our financial results may also be impacted by population growth or decline in our service areas.

Ticker: ATO, Sector: Utilities, Filed At: 2023-11-14T15:29:24-05:00

ITEM 1. Business. ##TABLE_ENDOverview and Strategy Atmos Energy Corporation, headquartered in Dallas, Texas, and incorporated in Texas and Virginia, is the countrys largest natural-gas-only distributor based on number of customers. We safely deliver reliable, efficient and abundant natural gas through regulated sales and transportation arrangements to over 3.3 million residential, commercial, public authority and industrial customers in eight states located primarily in the South. We also operate one of the largest intrastate pipelines in Texas based on miles of pipe. Atmos Energy's vision is to be the safest provider of natural gas services. We will be recognized for exceptional customer service, for being a great employer and for achieving superior financial results. Since 2011, our operating strategy has focused on modernizing our business and infrastructure while reducing regulatory lag. This operating strategy supports continued investment in safety, innovation, environmental sustainability and our communities. Operating Segments As of September 30, 2023, we manage and review our consolidated operations through the following reportable segments: The distribution segment is primarily comprised of our regulated natural gas distribution and related sales operations in eight states. The pipeline and storage segment is comprised primarily of the pipeline and storage operations of our Atmos Pipeline-Texas division and our natural gas transmission operations in Louisiana. Distribution Segment Overview The following table summarizes key information about our six regulated natural gas distribution divisions, presented in order of total rate base. ##TABLE_START Division Service Areas Communities Served Customer Meters Mid-Tex Texas, including the Dallas/Fort Worth Metroplex 550 1,856,356 Kentucky/Mid-States Kentucky 220 185,630 Tennessee 165,267 Virginia 25,083 Louisiana Louisiana 270 378,483 West Texas Amarillo, Lubbock, Midland 80 330,490 Mississippi Mississippi 110 273,586 Colorado-Kansas Colorado 170 129,197 Kansas 142,292 ##TABLE_ENDWe operate in our service areas under terms of non-exclusive franchise agreements granted by the various cities and towns that we serve. At September 30, 2023, we held 1,021 franchises having terms generally ranging from five to 35 years. A significant number of our franchises expire each year, which require renewal prior to the end of their terms. Historically, we have successfully renewed these franchises and believe that we will continue to be able to renew our franchises as they expire. Revenues in this operating segment are established by regulatory authorities in the states in which we operate. These rates are intended to be sufficient to cover the costs of conducting business, including a reasonable return on invested capital. In addition, we transport natural gas for others through our distribution systems. Rates established by regulatory authorities often include cost adjustment mechanisms for costs that (i) are subject to significant price fluctuations compared to our other costs, (ii) represent a large component of our cost of service and (iii) are generally outside our control. Purchased gas cost adjustment mechanisms represent a traditional and common form of cost adjustment mechanism. Purchased gas cost adjustment mechanisms provide a method of recovering purchased gas costs on an ongoing basis without filing a rate case because they provide a dollar-for-dollar offset to increases or decreases in the cost of natural gas. Therefore, although substantially all of our distribution operating revenues fluctuate with the cost of gas that we purchase, distribution operating income is generally not affected by fluctuations in the cost of gas. Additionally, some jurisdictions have performance-based ratemaking adjustments to provide incentives to minimize purchased gas costs through improved storage management and use of financial instruments to reduce volatility in gas costs. Under the performance-based ratemaking adjustments, purchased gas costs savings are shared between the Company and its customers. Our supply of natural gas is provided by a variety of suppliers, including independent producers and marketers. The gas is delivered into our systems by various pipeline companies, withdrawals of gas from proprietary and contracted storage assets and base load and peaking arrangements, as needed. Supply arrangements consist of both base load and peaking quantities and are contracted from our suppliers on a firm basis with various terms at market prices. Base load quantities are those that flow at a constant level throughout the month and peaking quantities provide the flexibility to change daily quantities to match increases or decreases in requirements related to weather conditions. Except for local production purchases, we select our natural gas suppliers through a competitive bidding process by periodically requesting proposals from suppliers. We select these suppliers based on their ability to reliably deliver gas supply to our designated firm pipeline receipt points at the lowest reasonable cost. Major suppliers during fiscal 2023 were Cima Energy, LP, ConocoPhillips Company, EnLink Gas Marketing LP, Enterprise Navitas Midstream Midland Basin LLC, Hartree Partners, L.P., Sequent Energy Management LLC, Symmetry Energy Solutions, LLC, Targa Gas Marketing LLC, Texla Energy Management, Inc. and Twin Eagle Resource Management, LLC. The combination of base load and peaking agreements, coupled with the withdrawal of gas held in storage, allows us the flexibility to adjust to changes in weather, which minimizes our need to enter into long-term firm commitments. We estimate our peak-day availability of natural gas supply to be approximately 5.3 Bcf. The peak-day demand for our distribution operations in fiscal 2023 was on December 23, 2022, when sales to customers reached approximately 4.2 Bcf. Currently, our distribution divisions utilize 35 pipeline transportation companies, both interstate and intrastate, to transport our natural gas. The pipeline transportation agreements are firm and many of them have pipeline no-notice storage service, which provides for daily balancing between system requirements and nominated flowing supplies. These agreements have been negotiated with the shortest term necessary while still maintaining our right of first refusal. The natural gas supply for our Mid-Tex Division is delivered primarily by our APT Division. To maintain our deliveries to high priority customers, we have the ability, and have exercised our right, to interrupt or curtail service to certain customers pursuant to contracts and applicable state regulations or statutes. Our customers demand on our system is not necessarily indicative of our ability to meet current or anticipated market demands or immediate delivery requirements because of factors such as the physical limitations of gathering, storage and transmission systems, the duration and severity of cold weather, the availability of gas reserves from our suppliers, the ability to purchase additional supplies on a short-term basis and actions by federal and state regulatory authorities. Interruption and curtailment rights provide us the flexibility to meet the human-needs requirements of our customers on a reliable basis. Priority allocations imposed by federal and state regulatory agencies, as well as other factors beyond our control, may affect our ability to meet the demands of some of our customers. Pipeline and Storage Segment Overview Our pipeline and storage segment consists of the pipeline and storage operations of APT and our natural gas transmission operations in Louisiana. APT is one of the largest intrastate pipeline operations in Texas with a heavy concentration in the established natural gas-producing areas of central, northern and eastern Texas, extending into or near the major producing areas of the Barnett Shale, the Texas Gulf Coast and the Permian Basin of West Texas. Through its system, APT provides transportation and storage services to our Mid-Tex Division, other third party local distribution companies, industrial and electric generation customers, marketers and producers. As part of its pipeline operations, APT owns and operates five underground storage facilities in Texas. Revenues earned from transportation and storage services for APT are subject to traditional ratemaking governed by the RRC. Rates are updated through periodic filings made under Texas GRIP. GRIP allows us to include in our rate base annually approved capital costs incurred in the prior calendar year provided that we file a complete rate case at least once every five years; the most recent of which was filed in May 2023. APTs existing regulatory mechanisms allow certain transportation and storage services to be provided under market-based rates. Our natural gas transmission operations in Louisiana are comprised of a 21-mile pipeline located in the New Orleans, Louisiana area that is primarily used to aggregate gas supply for our distribution division in Louisiana under a long-term contract and, on a more limited basis, to third parties. The demand fee charged to our Louisiana distribution division for these services is subject to regulatory approval by the Louisiana Public Service Commission. We also manage two asset management plans that serve distribution affiliates of the Company, which have been approved by applicable state regulatory commissions. Generally, these asset management plans require us to share with our distribution customers a significant portion of the cost savings earned from these arrangements. Ratemaking Activity Overview The method of determining regulated rates varies among the states in which our regulated businesses operate. The regulatory authorities have the responsibility of ensuring that utilities in their jurisdictions operate in the best interests of customers while providing utility companies the opportunity to earn a reasonable return on their investment. Generally, each regulatory authority reviews rate requests and establishes a rate structure intended to generate revenue sufficient to cover the costs of conducting business, including a reasonable return on invested capital. Our rate strategy focuses on reducing or eliminating regulatory lag, obtaining adequate returns and providing stable, predictable margins, which benefit both our customers and the Company. As a result of our ratemaking efforts in recent years, Atmos Energy has: Formula rate mechanisms in place in four states that provide for an annual rate review and adjustment to rates. Infrastructure programs in place in all of our states that provide for an annual adjustment to rates for qualifying capital expenditures. Through our annual formula rate mechanisms and infrastructure programs, we have the ability to recover approximately 90 percent of our capital expenditures within six months and substantially all of our capital expenditures within twelve months. Authorization in tariffs, statute or commission rules that allows us to defer certain elements of our cost of service such as depreciation, ad valorem taxes and pension costs, until they are included in rates. WNA mechanisms in seven states that serve to minimize the effects of weather on approximately 96 percent of our distribution residential and commercial revenues. The ability to recover the gas cost portion of bad debts in five states which represents approximately 80 percent of our distribution residential and commercial revenues. The following tables provides a jurisdictional rate summary for our regulated operations as of September 30, 2023. This information is for regulatory purposes only and may not be representative of our actual financial position. ##TABLE_START Division Jurisdiction Effective Date of Last Rate/GRIP Action Rate Base (thousands) (1) Authorized Rate of Return (1) Authorized Debt/ Equity Ratio (1) Authorized Return on Equity (1) Atmos Pipeline Texas Texas (5) 05/17/2023 $4,055,375 8.87% 47/53 11.50% Colorado-Kansas Colorado 05/14/2023

229,565 7.00% 42-45/55-58 9.3% - 9.6% Colorado SSIR 01/01/2023 31,993 7.00% 42-45/55-58 9.3% - 9.6% Kansas 05/09/2023 295,070 (4) (4) (4) Kansas SIP 04/01/2023 13,270 7.03% 44/56 9.10% Kentucky/Mid-States Kentucky 05/20/2022 568,506 6.82% 45/55 9.23% Kentucky-PRP 10/02/2022 14,375 6.94% 45/55 9.45% Tennessee 06/01/2023 499,447 7.58% 38/62 9.80% Virginia 04/01/2019 47,827 7.43% 42/58 9.20% Virginia-SAVE 10/01/2022 11,753 7.43% 42/58 9.20% Louisiana Louisiana 07/01/2023 1,094,373 7.30% (4) (4) Mid-Tex Mid-Tex Cities (7) 10/01/2022 5,234,981 (6) 7.28% 42/58 9.80% Mid-Tex ATM Cities 06/09/2023 5,932,535 (6) 7.97% 40/60 9.80% Mid-Tex Environs 06/01/2023 5,932,542 (6) 7.97% 40/60 9.80% Mid-Tex Dallas 09/01/2023 5,904,692 (6) 7.43% 40/60 9.80% Mississippi Mississippi 11/01/2022 525,348 7.53% (4) (4) Mississippi - SIR 11/01/2022 390,276 7.53% (4) (4) West Texas West Texas Cities (8) (10) 10/01/2022 855,328 (9) 7.28% 42/58 9.80% West Texas - ALDC 06/09/2023 960,622 (9) 7.35% 41/59 (4) West Texas - Environs 06/01/2023 958,159 (9) 7.97% 40/60 9.80% West Texas - Triangle 06/01/2023 56,279 7.71% 40/60 9.80% ##TABLE_END ##TABLE_START Division Jurisdiction Bad Debt Rider (2) Formula Rate Infrastructure Mechanism Performance Based Rate Program (3) WNA Period Atmos Pipeline Texas Texas No Yes Yes N/A N/A Colorado-Kansas Colorado No No Yes No N/A Kansas Yes No Yes Yes October-May Kentucky/Mid-States Kentucky Yes No Yes Yes November-April Tennessee Yes Yes Yes Yes October-April Virginia Yes No Yes No January-December Louisiana Louisiana No Yes Yes No December-March Mid-Tex Cities Texas Yes Yes Yes No November-April Mid-Tex Dallas Texas Yes Yes Yes No November-April Mississippi Mississippi No Yes Yes No November-April West Texas Texas Yes Yes Yes No October-May ##TABLE_END (1) The rate base, authorized rate of return, authorized debt/equity ratio and authorized return on equity presented in this table are those from the most recent approved regulatory filing for each jurisdiction. These rate bases, rates of return, debt/equity ratios and returns on equity are not necessarily indicative of current or future rate bases, rates of return or returns on equity. (2) The bad debt rider allows us to recover from customers the gas cost portion of customer accounts that have been written off. (3) The performance-based rate program provides incentives to distribution companies to minimize purchased gas costs by allowing the companies and their customers to share the purchased gas costs savings. (4) A rate base, rate of return, return on equity or debt/equity ratio was not included in the respective state commissions final decision. (5) On October 24, 2023, APT and the intervening parties in its general rate case filed a Joint Notice of Settlement and Proposed Order. The settlement proposes a rate base of $4.3 billion, an authorized return of 8.49%, a debt/equity ratio of 40/60 and an authorized ROE of 11.45%. We anticipate the settlement agreement will be on the RRC's agenda for its December 13, 2023 meeting. (6) The Mid-Tex rate base represents a system-wide, or 100 percent, of the Mid-Tex Divisions rate base. (7) The Mid-Tex Cities approved the Formula Rate Mechanism filing with rates effective October 1, 2023, which included a rate base of $6.1 billion, an authorized return of 7.35%, a debt/equity ratio of 42/58 and an authorized ROE of 9.80%. (8) The West Texas Cities includes all West Texas Division cities except Amarillo, Lubbock, Dalhart and Channing (ALDC). (9) The West Texas rate base represents a "system-wide," or 100 percent, of the West Texas Division's rate base. (10) The West Texas Cities approved the Formula Rate Mechanism filing with rates effective October 1, 2023, which included a rate base of $965.3 million, an authorized return of 7.35%, a debt/equity ratio of 42/58 and an authorized ROE of 9.80%. Although substantial progress has been made in recent years to improve rate design and recovery of investment across our service areas, we are continuing to seek improvements in rate design to address cost variations and pursue tariffs that reduce regulatory lag associated with investments. Further, potential changes in federal energy policy, federal safety regulations and changing economic conditions will necessitate continued vigilance by the Company and our regulators in meeting the challenges presented by these external factors. Recent Ratemaking Activity The amounts described in the following sections represent the annual operating income that was requested or received in each rate filing, which may not necessarily reflect the stated amount referenced in the final order, as certain operating costs may have changed as a result of the commission's or other governmental authority's final ruling. Our ratemaking outcomes include the refund (return) of excess deferred income taxes (EDIT) resulting from previously enacted tax reform legislation and do not reflect the true economic benefit of the outcomes because they do not include the corresponding income tax benefit. The following tables summarize the annualized ratemaking outcomes we implemented in each of the last three fiscal years. ##TABLE_START Rate Action Annual Increase (Decrease) in Operating Income EDIT Impact Annual Increase (Decrease) in Operating Income Excluding EDIT (In thousands) 2023 Filings: Annual formula rate mechanisms $ 258,824 $ (1,099) $ 257,725 Rate case filings 2,940 6,791 9,731 Other ratemaking activity 1,320 1,320 Total 2023 Filings $ 263,084 $ 5,692 $ 268,776 2022 Filings: Annual formula rate mechanisms $ 169,354 $ 33,249 $ 202,603 Rate case filings 5,938 7,379 13,317 Other ratemaking activity (370) (370) Total 2022 Filings $ 174,922 $ 40,628 $ 215,550 2021 Filings: Annual formula rate mechanisms $ 181,459 $ 39,306 $ 220,765 Rate case filings 5,119 1,168 6,287 Other ratemaking activity (877) (877) Total 2021 Filings $ 185,701 $ 40,474 $ 226,175 ##TABLE_ENDThe following ratemaking efforts seeking $264.6 million in annual operating income were initiated during fiscal 2023 but had not been completed or implemented as of September 30, 2023: ##TABLE_START Division Rate Action Jurisdiction Operating Income Requested (In thousands) Atmos Pipeline - Texas Rate Case Texas (1) $ 107,417 Colorado-Kansas Infrastructure Mechanism Kansas (2) 1,755 Kentucky/Mid-States Infrastructure Mechanism Virginia (3) 672 Kentucky/Mid-States Infrastructure Mechanism Kentucky (4) 3,424 Kentucky/Mid-States Rate Case Virginia 2,752 Mid-Tex Formula Rate Mechanism Mid-Tex Cities (5) 113,768 Mississippi Infrastructure Mechanism Mississippi 10,969 Mississippi Formula Rate Mechanism Mississippi 13,793 West Texas Formula Rate Mechanism West Texas Cities (6) 10,085 $ 264,635 ##TABLE_END(1) On October 24, 2023, APT and the intervening parties in its general rate case filed a Joint Notice of Settlement and

Proposed Order. We anticipate the settlement agreement will be on the RRC's agenda for its December 13, 2023 meeting. If approved, the settlement would result in a $27.0 million increase in annual operating income, exclusive of the impact of the cessation of $36.9 million in excess deferred income tax refunds, which are substantially offset by a corresponding increase in income taxes. New rates are anticipated to be implemented on January 1, 2024. (2) The Kansas Corporation Commission approved the GSRS filing on November 2, 2023, with rates effective November 2, 2023. (3) On September 11, 2023, the State Corporation Commission of Virginia approved a rate increase of $0.6 million effective October 1, 2023. (4) On September 29, 2023, the Kentucky Public Service Commission approved a rate increase of $2.9 million effective October 1, 2023. (5) The Mid-Tex Cities approved a rate increase of $98.6 million. New rates were implemented on October 1, 2023. (6) The West Texas Cities approved a rate increase of $8.6 million. New rates were implemented on October 1, 2023. Our recent ratemaking activity is discussed in greater detail below. Annual Formula Rate Mechanisms As an instrument to reduce regulatory lag, formula rate mechanisms allow us to refresh our rates on an annual basis without filing a formal rate case. However, these filings still involve discovery by the appropriate regulatory authorities prior to the final determination of rates under these mechanisms. We currently have specific infrastructure programs in all of our distribution divisions with tariffs in place to permit the investment associated with these programs to have their surcharge rate adjusted annually to recover approved capital costs incurred in a prior test-year period. The following table summarizes our annual formula rate mechanisms by state. ##TABLE_START Annual Formula Rate Mechanisms State Infrastructure Programs Formula Rate Mechanisms Colorado System Safety and Integrity Rider (SSIR) Kansas Gas System Reliability Surcharge (GSRS), System Integrity Program (SIP) Kentucky Pipeline Replacement Program (PRP) Louisiana (1) Rate Stabilization Clause (RSC) Mississippi System Integrity Rider (SIR) Stable Rate Filing (SRF) Tennessee (1) Annual Rate Mechanism (ARM) Texas Gas Reliability Infrastructure Program (GRIP), (1) Dallas Annual Rate Review (DARR), Rate Review Mechanism (RRM) Virginia Steps to Advance Virginia Energy (SAVE) ##TABLE_END(1) Infrastructure mechanisms in Texas, Louisiana and Tennessee allow for the deferral of all expenses associated with capital expenditures incurred pursuant to these rules, which primarily consists of interest, depreciation and other taxes (Texas only), until the next rate proceeding (rate case or annual rate filing), at which time investment and costs would be recoverable through base rates. The following table summarizes our annual formula rate mechanisms with effective dates during the fiscal years ended September 30, 2023, 2022 and 2021: ##TABLE_START Division Jurisdiction Test Year Ended Increase (Decrease) in Annual Operating Income EDIT Impact Increase (Decrease) in Annual Operating Income Excluding EDIT Effective Date (In thousands) 2023 Filings: Louisiana Louisiana 12/2022 $ 14,466 $ 17 $ 14,483 07/01/2023 Mid-Tex DARR (1) 09/2022 17,345 51 17,396 06/14/2023 Mid-Tex ATM Cities 12/2022 12,825 12,825 06/09/2023 West Texas Amarillo, Lubbock, Dalhart and Channing 12/2022 6,938 6,938 06/09/2023

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West Texas Triangle 12/2022 717 717 06/01/2023 West Texas Environs 12/2022 1,332 1,332 06/01/2023 Mid-Tex Environs 12/2022 5,983 5,983 06/01/2023 Kentucky/Mid-States Tennessee ARM 09/2022 14 (1,509) (1,495) 06/01/2023 Atmos Pipeline - Texas Texas 12/2022 84,931 84,931 05/17/2023 Colorado-Kansas Kansas SIP 12/2022 772 772 04/01/2023 Colorado-Kansas Colorado SSIR 12/2023 1,971 1,971 01/01/2023 Mississippi Mississippi - SIR 10/2023 8,560 8,560 11/01/2022 Mississippi Mississippi - SRF 10/2023 12,188 778 12,966 11/01/2022 Kentucky/Mid-States Kentucky PRP 09/2023 1,588 1,588 10/02/2022 Mid-Tex Mid-Tex Cities RRM 12/2021 81,402 (395) 81,007 10/01/2022 West Texas West Texas Cities RRM 12/2021 7,315 (41) 7,274 10/01/2022 Kentucky/Mid-States Virginia - SAVE 09/2023 477 477 10/01/2022 Total 2023 Filings $ 258,824 $ (1,099) $ 257,725 2022 Filings: Kentucky/Mid-States Tennessee ARM 09/2021 $ 2,466 $ $ 2,466 07/01/2022 Louisiana Louisiana 12/2021 17,650 (10,389) 7,261 07/01/2022 West Texas Amarillo, Lubbock, Dalhart and Channing 12/2021 6,122 6,122 06/11/2022 West Texas Triangle 12/2021 1,549 1,549 06/11/2022 West Texas Environs 12/2021 1,221 1,221 06/11/2022 Mid-Tex ATM Cities 12/2021 12,815 12,815 06/10/2022 Mid-Tex Environs 12/2021 5,646 5,646 06/10/2022 Mid-Tex DARR (2) 09/2021 13,201 13,201 05/25/2022 Atmos Pipeline - Texas Texas 12/2021 78,750 78,750 05/18/2022 Colorado-Kansas Kansas SIP 12/2021 623 623 04/01/2022 Colorado-Kansas Kansas GSRS 09/2021 1,820 1,820 02/01/2022 Colorado-Kansas Colorado SSIR 12/2022 2,610 2,610 01/01/2022 Mid-Tex Mid-Tex Cities RRM 12/2020 21,673 33,851 55,524 12/01/2021 West Texas West Texas Cities RRM 12/2020 151 3,347 3,498 12/01/2021 Mississippi Mississippi - SIR 10/2022 8,354 2,123 10,477 11/01/2021 Mississippi Mississippi - SRF 10/2022 (5,624) 4,317 (1,307) 11/01/2021 Kentucky/Mid-States Virginia - SAVE 09/2022 327 327 10/01/2021 Total 2022 Filings $ 169,354 $ 33,249 $ 202,603 ##TABLE_END##TABLE_START 2021 Filings: Mid-Tex Environs 12/2020 $ 4,632 $ $ 4,632 09/01/2021 Louisiana Louisiana 12/2020 (2,407) 24,192 21,785 07/01/2021 Mid-Tex ATM Cities (3) 12/2020 11,085 11,085 06/11/2021 West Texas Triangle (3) 12/2020 416 416 06/11/2021 West Texas Environs (3) 12/2020 1,267 1,267 06/11/2021 Mid-Tex DARR (3) 09/2020 1,708 15,114 16,822 06/09/2021 Kentucky/Mid-States Tennessee ARM 09/2020 10,260 10,260 06/01/2021 Atmos Pipeline - Texas Texas 12/2020 43,868 43,868 05/11/2021 Colorado-Kansas Kansas GSRS 09/2020 1,695 1,695 02/01/2021 Colorado-Kansas Colorado SSIR 12/2021 2,366 2,366 01/01/2021 Mid-Tex Mid-Tex Cities RRM 12/2019 82,645 82,645 12/01/2020 West Texas West Texas Cities RRM 12/2019 5,645 5,645 12/01/2020 Mississippi Mississippi - SIR 10/2021 10,556 10,556 11/01/2020 Mississippi Mississippi - SRF 10/2021 5,856 5,856 11/01/2020 Kentucky/Mid-States Virginia - SAVE 09/2021 305 305 10/01/2020 Kentucky/Mid-States Kentucky PRP 09/2021 1,562 1,562 10/01/2020 Total 2021 Filings $ 181,459 $ 39,306 $ 220,765 ##TABLE_END(1) The rate increase for this filing was approved based on the effective date herein; however, the new rates were implemented beginning September 1, 2023. (2) The rate increase for this filing was approved based on the effective date herein; however, the new rates were implemented beginning

September 1, 2022. (3) The rate increases for these filings were approved based on the effective dates herein; however, the new rates were implemented beginning September 1, 2021. Rate Case Filings A rate case is a formal request from Atmos Energy to a regulatory authority to increase rates that are charged to customers. Rate cases may also be initiated when the regulatory authorities request us to justify our rates. This process is referred to as a show cause action. Adequate rates are intended to provide for recovery of the Companys costs as well as a reasonable rate of return to our shareholders and ensure that we continue to safely deliver reliable, reasonably priced natural gas service to our customers. The following table summarizes our recent rate case activity during the fiscal years ended September 30, 2023, 2022 and 2021: ##TABLE_START Division State Increase in Annual Operating Income EDIT Impact Increase in Annual Operating Income Excluding EDIT Effective Date (In thousands) 2023 Rate Case Filings: Colorado-Kansas Colorado $ 913 $ (54) $ 859 05/14/2023 Colorado-Kansas Kansas 2,027 6,845 8,872 05/09/2023 Total 2023 Rate Case Filings $ 2,940 $ 6,791 $ 9,731 2022 Rate Case Filings: Kentucky/Mid-States Kentucky (1) $ 5,938 $ 7,379 $ 13,317 05/20/2022 Total 2022 Rate Case Filings $ 5,938 $ 7,379 $ 13,317 2021 Rate Case Filings: West Texas (ALDC) Texas $ 5,119 $ 1,168 $ 6,287 06/01/2021 Total 2021 Rate Case Filings $ 5,119 $ 1,168 $ 6,287 ##TABLE_END(1) The rate case outcome for Kentucky is inclusive of the fiscal 2022 pipeline replacement program. Other Ratemaking Activity The following table summarizes other ratemaking activity during the fiscal years ended September 30, 2023, 2022 and 2021: ##TABLE_START Division Jurisdiction Rate Activity Increase (Decrease) in Annual Operating Income Effective Date (In thousands) 2023 Other Rate Activity: Colorado-Kansas Kansas Ad Valorem (1) $ 1,320 02/01/2023 Total 2023 Other Rate Activity $ 1,320 2022 Other Rate Activity: Colorado-Kansas Kansas Ad Valorem (1) $ (370) 02/01/2022 Total 2022 Other Rate Activity $ (370) 2021 Other Rate Activity: Colorado-Kansas Kansas Ad-Valorem (1) $ (877) 02/01/2021 Total 2021 Other Rate Activity $ (877) ##TABLE_END (1) The Ad Valorem filing relates to property taxes that are either over or undercollected compared to the amount included in our Kansas service area's base rates. Other Regulation We are regulated by various state or local public utility authorities. We are also subject to regulation by the United States Department of Transportation with respect to safety requirements in the operation and maintenance of our transmission and distribution facilities. In addition, our operations are also subject to various state and federal laws regulating environmental matters. From time to time, we receive inquiries regarding various environmental matters. We believe that our properties and operations comply with, and are operated in conformity with, applicable safety and environmental statutes and regulations. There are no administrative or judicial proceedings arising under environmental quality statutes pending or known to be contemplated by governmental agencies which would have a material adverse effect on us or our operations. The Pipeline and Hazardous Materials Safety Administration (PHMSA), within the U.S. Department of Transportation, develops and enforces regulations for the safe, reliable and environmentally sound operation of the pipeline transportation system. The PHMSA pipeline safety statutes provide for states to assume safety authority over intrastate natural transmission and distribution gas pipelines. State pipeline safety programs are responsible for adopting and enforcing the federal and state pipeline safety regulations for intrastate natural gas transmission and distribution pipelines. The Federal Energy Regulatory Commission (FERC) allows, pursuant to Section 311 of the Natural Gas Policy Act (NGPA), gas transportation services through our APT assets on behalf of interstate pipelines or local distribution companies served by interstate pipelines, without subjecting these assets to the jurisdiction of the FERC under the NGPA. Additionally, the FERC has regulatory authority over the use and release of interstate pipeline and storage capacity. The FERC also has authority to detect and prevent market manipulation and to enforce compliance with FERCs other rules, policies and orders by companies engaged in the sale, purchase, transportation or storage of natural gas in interstate commerce. We have taken what we believe are the necessary and appropriate steps to comply with these regulations. The SEC and the Commodities Futures Trading Commission, pursuant to the DoddFrank Act, established numerous regulations relating to U.S. financial markets. We enacted procedures and modified existing business practices and contractual arrangements to comply with such regulations. Competition Although our regulated distribution operations are not currently in significant direct competition with any other distributors of natural gas to residential and commercial customers within our service areas, we do compete with other natural gas suppliers and suppliers of alternative fuels for sales to industrial customers. We compete in all aspects of our business with alternative energy sources, including, in particular, electricity. Electric utilities offer electricity as a rival energy source and compete for the space heating, water heating and cooking markets. Promotional incentives, improved equipment efficiencies and promotional rates all contribute to the acceptability of electrical equipment. The principal means to compete against alternative fuels is lower prices, and natural gas historically has maintained its price advantage in the residential, commercial and industrial markets. Our pipeline and storage operations have historically faced competition from other existing intrastate pipelines seeking to provide or arrange transportation, storage and other services for customers. In the last few years, several new pipelines have been completed, which has increased the level of competition in this segment of our business. Employees The Corporate Responsibility, Sustainability, and Safety Committee of the Board of Directors oversees matters relating to equal employment opportunities, diversity, and inclusion; human workplace rights; employee health and safety; and the Companys vision, values, and culture. It oversees the Company's policies, practices and procedures relating to sustainability to support the alignment of the Company's sustainability strategy with the Company's corporate strategy. Part of our vision is to create a culture that respects and appreciates diversity. For this reason, we strive to have a workforce that reflects the communities we serve. At September 30, 2023, we had 5,019 employees. We monitor our workforce data on a calendar year basis. As of December 31, 2022, the last date for which information is available, 61 percent of our employees worked in field roles and 39 percent worked in support/shared services roles. No employees are subject to a collective bargaining agreement. To recruit and hire individuals with a variety of skills, talents, backgrounds and experiences, we value and cultivate our strong relationships with various community and diversity outreach sources. We also target jobs fairs including those focused on minority, veteran and women candidates and partner with local colleges and universities to identify and recruit qualified applicants in each of the cities and towns we serve. Finally, we believe we offer a competitive benefits program to help retain our employees. We perform succession planning annually to ensure that we develop and sustain a strong bench of talent capable of performing at the highest levels. Not only is talent identified, but potential paths of development are discussed to ensure that employees have an opportunity to build their skills and are well-prepared for future roles. The strength of our succession planning process is evident through our long history of promoting our leaders from within the organization. Available Information Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports, and amendments to those reports, and other forms that we file with or furnish to the Securities and Exchange Commission (SEC) at their website, www.sec.gov , are also available free of charge at our website, www.atmosenergy.com/company/publications-and-sec-filings , as soon as reasonably practicable, after we electronically file these reports with, or furnish these reports to, the SEC. We will also provide copies of these reports free of charge upon request to Shareholder Relations at the address and telephone number appearing below: Shareholder Relations Atmos Energy Corporation P.O. Box 650205 Dallas, Texas 75265-0205 972-855-3729 Corporate Governance In accordance with and pursuant to relevant related rules and regulations of the SEC as well as corporate governance-related listing standards of the New York Stock Exchange (NYSE), the Board of Directors of the Company has established and periodically updated our Corporate Governance Guidelines and Code of Conduct, which is applicable to all directors, officers and employees of the Company. In addition, in accordance with and pursuant to such NYSE listing standards, our Chief Executive Officer during fiscal 2023, John K. Akers, certified to the New York Stock Exchange that he was not aware of any violations by the Company of NYSE corporate governance listing standards. The Board of Directors also annually reviews and updates, if necessary, the charters for each of its Audit, Human Resources, Nominating and Corporate Governance and Corporate Responsibility, Sustainability and Safety Committees. All of the foregoing documents are posted on our website at www.atmosenergy.com/company/corporate-responsiblity-reports . We will also provide copies of all corporate governance documents free of charge upon request to Shareholder Relations at the address listed above. ##TABLE_START ITEM 1A. Risk Factors. ##TABLE_ENDOur financial and operating results are subject to a number of risk factors, many of which are not within our control. Investors should carefully consider the following discussion of risk factors as well as other information appearing in this report. These factors include the following, which are organized by category: Regulatory and Legislative Risks We are subject to federal, state and local regulations that affect our operations and financial results. We are subject to regulatory oversight from various federal, state and local regulatory authorities in the eight states that we serve. Therefore, our returns are continuously monitored and are subject to challenge for their reasonableness by the appropriate regulatory authorities or other third-party intervenors. In the normal course of business, as a regulated entity, we often need to place assets in service and establish historical test periods before rate cases that seek to adjust our allowed returns to recover that investment can be filed. Further, the regulatory review process can be lengthy in the context of traditional ratemaking. Because of this process, we suffer the negative financial effects of having placed assets in service without the benefit of rate relief, which is commonly referred to as regulatory lag. Regulatory authorities in the states we serve have approved various infrastructure and annual rate adjustment mechanisms to effectively reduce the regulatory lag inherent in the ratemaking process. Regulatory lag could significantly increase if the regulatory authorities modify or terminate these rate mechanisms. The regulatory process also involves the risk that regulatory authorities may (i) review our purchases of natural gas and adjust the amount of our gas costs that we pass through to our customers or (ii) limit or disallow the costs we may have incurred from our cost of service that can be recovered from customers. We are also subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local governmental authorities relating to protection of the environment and health and safety matters, including those that govern discharges of substances into the air and water, the management and disposal of hazardous substances and waste, the clean-up of contaminated sites, groundwater quality and availability, plant and wildlife protection, as well as work practices related to employee health and safety. Environmental legislation also requires that our facilities, sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Failure to comply with these laws, regulations, permits and licenses may expose us to fines, penalties or interruptions in our operations that could be significant to our financial results. In addition, existing environmental regulations may be revised or our operations may become subject to new regulations. Some of our operations are subject to increased federal regulatory oversight that could affect our operations and financial results. FERC has regulatory authority over some of our operations, including the use and release of interstate pipeline and storage capacity. FERC has adopted rules designed to prevent market power abuse and market manipulation and to promote compliance with FERCs other rules, policies and orders by companies engaged in the sale, purchase, transportation or storage of natural gas in interstate commerce. These rules carry increased penalties for violations. Although we have taken steps to structure current and future transactions to comply with applicable current FERC regulations, changes in FERC regulations or their interpretation by FERC or additional regulations issued by FERC in the future could also adversely affect our business, financial condition or financial results. We may experience increased federal, state and local regulation of the safety of our operations. The safety and protection of the public, our customers and our employees is our top priority. We constantly monitor and maintain our pipeline and distribution systems to ensure that natural gas is delivered safely, reliably and efficiently through our network of more than 75,000 miles of distribution and transmission lines. As in recent years, natural gas distribution and pipeline companies are continuing to encounter increasing federal, state and local oversight of the safety of their operations. Although we believe these are costs ultimately recoverable through our rates, the costs of complying with new laws and regulations may have at least a short-term adverse impact on our operating costs and financial results. Operational Risks We may incur significant costs and liabilities resulting from pipeline integrity and other similar programs and related repairs. PHMSA requires pipeline operators to develop integrity management programs to comprehensively evaluate certain areas along their pipelines and to take additional measures to protect pipeline segments located in high consequence areas where a leak or rupture could potentially do the most harm. As a pipeline operator, the Company is required to: perform ongoing assessments of pipeline integrity; identify and characterize applicable threats to pipeline segments that could impact a high consequence area; improve data collection, integration and analysis; repair and remediate the pipeline as necessary; and implement preventative and mitigating actions. The Company incurs significant costs associated with its compliance with existing PHMSA and comparable state regulations. Although we believe these are costs ultimately recoverable through our rates, the costs of complying with new laws and regulations may have at least a short-term adverse impact on our operating costs and financial results. For example, the adoption of new regulations requiring more comprehensive or stringent safety standards could require installation of new or modified safety controls, new capital projects, or accelerated maintenance programs, all of which could require a potentially significant increase in operating costs. Distributing, transporting and storing natural gas involve risks that may result in accidents and additional operating costs. Our operations involve a number of hazards and operating risks inherent in storing and transporting natural gas that could affect the public safety and reliability of our distribution system. While Atmos Energy, with the support from each of its regulatory commissions, is accelerating the replacement of pipeline infrastructure, operating issues such as leaks, accidents, equipment problems and incidents, including explosions and fire, could result in legal liability, repair and remediation costs, increased operating costs, significant increased capital expenditures, regulatory fines and penalties and other costs and a loss of customer confidence. We maintain liability and property insurance coverage in place for many of these hazards and risks. However, because some of our transmission pipeline and storage facilities are near or are in populated areas, any loss of human life or adverse financial results resulting from such events could be large. If these events were not fully covered by our general liability and property insurance, which policies are subject to certain limits and deductibles, our operations or financial results could be adversely affected. If contracted gas supplies, interstate pipeline and/or storage services are not available or delivered in a timely manner, our ability to meet our customers natural gas requirements may be impaired and our financial condition may be adversely affected. In order to meet our customers annual and seasonal natural gas demands, we must obtain a sufficient supply of natural gas, interstate pipeline capacity and storage capacity. If we are unable to obtain these, either from our suppliers inability to deliver the contracted commodity or the inability to secure replacement quantities, our financial condition and results of operations may be adversely affected. If a substantial disruption to or reduction in interstate natural gas pipelines transmission and storage capacity occurred due to operational failures or disruptions, legislative or regulatory actions, hurricanes, tornadoes, floods, extreme cold weather, terrorist or cyber-attacks or acts of war, our operations or financial results could be adversely affected. Our operations are subject to increased competition. In residential and commercial customer markets, our distribution operations compete with other energy products, such as electricity and propane. Our primary product competition is with electricity for heating, water heating and cooking. If customer growth slows or existing customers choose to conserve their use of gas or choose another energy product, reduced gas purchases and customer billings could adversely impact our business. In the case of industrial customers, such as manufacturing plants, adverse economic conditions, including higher gas costs, could cause these customers to use alternative sources of energy, such as electricity, or bypass our systems in favor of special competitive contracts with lower per-unit costs. Our pipeline and storage operations historically have faced limited competition from other existing intrastate pipelines and gas marketers seeking to provide or arrange transportation, storage and other services for customers. The completion of new pipelines in our service area may increase the competition in this segment of our business. Failure to attract and retain a qualified workforce could adversely affect our results of operations. The competition for talent has become increasingly intense and we may experience increased employee turnover due to a tightening labor market. If we are unable to recruit and retain an appropriately qualified workforce, the Company could encounter operating challenges primarily due to a loss of institutional knowledge and expertise, errors due to inexperience, or the lengthy time period typically required to adequately train replacement personnel. In addition, higher costs could result from loss of productivity, increased safety compliance issues, or cost of contract labor. Additionally, our ability to operate is contingent on maintaining a healthy workforce and a safe working environment. As a provider of essential services, we have an obligation to provide natural gas services to customers. Incidents that impact the health and availability of our workforce could threaten the continuity of our business operations. Natural disasters, terrorist activities or other significant events could adversely affect our operations or financial results. Natural disasters are always a threat to our assets and operations. In addition, the threat of terrorist activities could lead to increased economic instability and volatility in the price of natural gas that could affect our operations. Also, companies in our industry may face a heightened risk of exposure to actual acts of terrorism, which could subject our operations to increased risks. As a result, the availability of insurance covering such risks may become more limited, which could increase the risk that an event could adversely affect our operations or financial results. Technology and Cybersecurity Risks Increased dependence on technology may hinder the Companys business operations and adversely affect its financial condition and results of operations if such technologies fail. Over the last several years, the Company has implemented or acquired a variety of technological tools including both Company-owned information technology and technological services provided by outside parties. These tools and systems support critical functions including scheduling and dispatching of service technicians, automated meter reading systems, customer care and billing, operational plant logistics, management reporting and external financial reporting. The failure of these or other similarly important technologies, or the Companys inability to have these technologies supported, updated, expanded, or integrated into other technologies, could hinder its business operations and adversely impact its financial condition and results of operations. Although the Company has, when possible, developed alternative sources of technology and built redundancy into its computer networks and tools, there can be no assurance that these efforts would protect against all potential issues related to the loss of any such technologies. Cyber-attacks or acts of cyber-terrorism could disrupt our business operations and information technology systems or result in the loss or exposure of confidential or sensitive customer, employee or Company information. Our business operations and information technology systems may be vulnerable to an attack by individuals or organizations intending to disrupt our business operations and information technology systems, even though the Company has implemented policies, procedures and controls to prevent and detect these activities. We use our information technology systems to manage our distribution and intrastate pipeline and storage operations and other business processes. Disruption of those systems could adversely impact our ability to safely deliver natural gas to our customers, operate our pipeline and storage systems or serve our customers timely. Accordingly, if such an attack or act of terrorism were to occur, our operations and financial results could be adversely affected. In addition, we use our information technology systems to protect confidential or sensitive customer, employee and Company information developed and maintained in the normal course of our business. Any attack on such systems that would result in the unauthorized release of customer, employee or other confidential or sensitive data could have a material adverse effect on our business reputation, increase our costs and expose us to additional material legal claims and liability. Even though we have insurance coverage in place for many of these cyber-related risks, if such an attack or act of terrorism were to occur, our operations and financial results could be adversely affected to the extent not fully covered by such insurance coverage. Compliance with and changes in cybersecurity requirements have a cost and operational impact on our business, and failure to comply with such laws and regulations could adversely impact our reputation, results of operations, financial condition and/or cash flows. As cyber-attacks are becoming more sophisticated, U.S. government warnings have indicated that critical infrastructure assets, including pipeline infrastructure, may be specifically targeted by certain groups. In recent years, the U.S. government has issued directives that require critical pipeline owners to comply with mandatory reporting measures, designate a cybersecurity coordinator, provide vulnerability assessments and ensure compliance with certain cybersecurity requirements. Such directives or other requirements may require expenditure of significant additional resources to respond to cyber-attacks, to continue to modify or enhance protective measures, or to assess, investigate and remediate any critical infrastructure security vulnerabilities. Any failure to comply with such government regulations or failure in our cybersecurity protective measures may result in enforcement actions that may have a material adverse effect on our business, results of operations and financial condition. In addition, there is no certainty that costs incurred related to securing against threats will be recovered through rates. Climate Risks Adverse weather conditions could affect our operations or financial results. We have weather-normalized rates for approximately 96 percent of our residential and commercial revenues in our distribution operations, which substantially mitigates the adverse effects of warmer-than-normal weather for meters in those service areas. However, there is no assurance that we will continue to receive such regulatory protection from adverse weather in our rates in the future. The loss of such weather-normalized rates could have an adverse effect on our operations and financial results. In addition, our operating results may continue to vary somewhat with the actual temperatures during the winter heating season. Additionally, sustained cold weather could challenge our ability to adequately meet customer demand in our operations. Greenhouse gas emissions or other legislation or regulations intended to address climate change could increase our operating costs, adversely affecting our financial results, growth, cash flows and results of operations. Six of the eight states in which we operate have passed legislation to prevent local governments from limiting the types of energy available to customers. However, federal, regional and/or state legislative and/or regulatory initiatives may attempt to control or limit the causes of climate change, including greenhouse gas emissions, such as carbon dioxide and methane. Such laws or regulations could impose costs tied to greenhouse gas emissions, operational requirements or restrictions, or additional charges to fund energy efficiency activities. They could also provide a cost advantage to alternative energy sources, impose costs or restrictions on end users of natural gas, or result in other costs or requirements, such as costs associated with the adoption of new infrastructure and technology to respond to new mandates. The focus on climate change could adversely impact the reputation of fossil fuel products or services. The occurrence of the foregoing events could put upward pressure on the cost of natural gas relative to other energy sources, increase our costs and the prices we charge to customers, reduce the demand for natural gas or cause fuel switching to other energy sources, and impact the competitive position of natural gas and the ability to serve new or existing customers, adversely affecting our business, results of operations and cash flows. The operations and financial results of the Company could be adversely impacted as a result of climate change. As climate change occurs, our businesses could be adversely impacted. To the extent climate change results in materially increasing temperatures, financial results could be adversely affected through lower gas volumes and revenues. Climate change could also cause shifts in population, including customers moving away from our service territories. It could also result in more frequent and more severe weather events, such as hurricanes and tornadoes, which could increase our costs to repair damaged facilities and restore service to our customers or impact the cost of gas. If we were unable to deliver natural gas to our customers, our financial results would be impacted by lost revenues, and we generally would have to seek approval from regulators to recover restoration costs. To the extent we would be unable to recover those costs, or if higher rates resulting from our recovery of such costs would result in reduced demand for our services, our future business, financial condition or financial results could be adversely impacted. Financial, Economic and Market Risks Our growth in the future may be limited by the nature of our business, which requires extensive capital spending. Our operations are capital-intensive. We must make significant capital expenditures on a long-term basis to modernize our distribution and transmission system and to comply with the safety rules and regulations issued by the regulatory authorities responsible for the service areas we operate. In addition, we must continually build new capacity to serve the growing needs of the communities we serve. The magnitude of these expenditures may be affected by a number of factors, including new policy and regulations, and the general state of the economy. The liquidity required to fund our working capital, capital expenditures and other cash needs is provided from a combination of internally generated cash flows and external debt and equity financing. The cost and availability of borrowing funds from third party lenders or issuing equity is dependent on the liquidity of the credit markets, interest rates and other market conditions. This in turn may limit the amount of funds we can invest in our infrastructure. The Company is dependent on continued access to the credit and capital markets to execute our business strategy. Our long-term debt is currently rated as investment grade by Standard Poors Corporation and Moodys Investors Service, Inc. Similar to most companies, we rely upon access to both short-term and long-term credit and capital markets to satisfy our liquidity requirements. If adverse credit conditions were to cause a significant limitation on our access to the private credit and public capital markets, we could see a reduction in our liquidity. A significant reduction in our liquidity could in turn trigger a negative change in our ratings outlook or even a reduction in our credit ratings by one or more of the credit rating agencies. Such a downgrade could further limit our access to private credit and/or public capital markets and increase our costs of borrowing. While we believe we can meet our capital requirements from our operations and the sources of financing available to us, we can provide no assurance that we will continue to be able to do so in the future. The future effects on our business, liquidity and financial results of a deterioration of current conditions in the credit and capital markets could be material and adverse to us, both in the ways described above or in other ways that we do not currently anticipate. We are exposed to market risks that are beyond our control, which could adversely affect our financial results. We are subject to market risks beyond our control, including (i) commodity price volatility caused by market supply and demand dynamics, counterparty performance or counterparty creditworthiness and (ii) interest rate risk. We are generally insulated from commodity price risk through our purchased gas cost mechanisms. With respect to interest rate risk, increases in interest rates could adversely affect our future financial results to the extent that we do not recover our actual interest expense in our rates. The concentration of our operations in the State of Texas exposes our operations and financial results to economic conditions, weather patterns and regulatory decisions in Texas. Approximately 70 percent of our consolidated operations are located in the State of Texas. This concentration of our business in Texas means that our operations and financial results may be significantly affected by changes in the Texas economy in general, weather patterns and regulatory decisions by state and local regulatory authorities in Texas. A deterioration in economic conditions could adversely affect our customers and negatively impact our financial results. Any adverse changes in economic conditions in the states in which we operate could adversely affect the financial resources of many domestic households. As a result, our customers could seek to use less gas and it may be more difficult for them to pay their gas bills. This would likely lead to slower collections and higher than normal levels of accounts receivable. This, in turn, could increase our financing requirements. Additionally, should economic conditions deteriorate, our industrial customers could seek alternative energy sources, which could result in lower transportation volumes. Increased gas costs could adversely impact our customer base and customer collections and increase our level of indebtedness. Rapid increases in the costs of purchased gas would cause us to experience a significant increase in short-term or long-term debt. We must pay suppliers for gas when it is purchased, which can be significantly in advance of when these costs may be recovered through the collection of monthly customer bills for gas delivered. Increases in purchased gas costs also slow our natural gas distribution collections as customers may delay the payment of their gas bills, leading to higher than normal accounts receivable. This could result in higher short-term debt levels, greater collection efforts and increased bad debt expense. Our pension and other postretirement benefit plans are subject to investment and interest rate risk that could negatively impact our financial condition. We have pension and other postretirement benefit plans that provide benefits to many of our employees and retirees. Costs of providing benefits and related-funding requirements of these plans are subject to changes in the market value of the assets that fund the plans. The funded status of the plans and the related costs reflected in the Companys financial statements are affected by various factors, which are subject to an inherent degree of uncertainty, including economic conditions, financial market performance, interest rates, life expectancies and demographics. Poor investment returns or lower interest rates may necessitate accelerated funding of the plans to meet minimum federal government requirements, which could have an adverse

impact on the Companys financial condition and results of operations.
##TABLE_START

Ticker: AVA, Sector: Utilities, Filed At: 2023-02-21T21:28:19-05:00

ITEM 1. B USINESS COMPANY OVERVIEW Avista Corp., incorporated in the territory of Washington in 1889, is primarily an electric and natural gas utility with certain other business ventures. Our mission is to improve our customers lives through innovative energy solutions, safely, responsibly and affordably. Our corporate headquarters is in Spokane, Washington, the second-largest city in Washington. Spokane serves as the business, transportation, medical, industrial and cultural hub of the Inland Northwest region (eastern Washington and northern Idaho). Regional services include government and higher education, medical services, retail trade and finance. Through our subsidiary AELP, we also provide electric utility services in Juneau, Alaska. As of December 31, 2022, we have two reportable business segments as follows: Avista Utilities an operating division of Avista Corp., comprising the regulated utility operations in Washington, Idaho, Oregon and Montana. Avista Utilities provides electric distribution and transmission, and natural gas distribution services in parts of eastern Washington and northern Idaho. Avista Utilities also provides natural gas distribution service in parts of northeastern and southwestern Oregon. Avista Utilities has electric generating facilities in Washington, Idaho, Oregon and Montana. Avista Utilities also supplies electricity to a small number of customers in Montana, most of whom are employees who operate Avista Utilities' Noxon Rapids generating facility. Avista Utilities also engages in wholesale purchases and sales of electricity and natural gas as an integral part of energy resource management and its load-serving obligation. AELP a regulated utility providing electric services in Juneau, Alaska that is a wholly-owned subsidiary and the primary operating subsidiary of AERC. We have other businesses, including venture fund investments, real estate investments, as well as certain other investments made by Avista Capital, which is a direct, wholly owned subsidiary of Avista Corp. These activities do not represent a reportable business segment and are conducted by various direct and indirect subsidiaries of Avista Corp. Total Avista Corp. shareholders equity was $2.3 billion as of December 31, 2022, which includes a $149.9 million investment in Avista Capital and a $110.9 million investment in AERC. See Note 24 of the Notes to Consolidated Financial Statements for information with respect to the operating performance of each business segment (and other subsidiaries). Human Capital Our approach to people is a critical strategy and the priorities for this strategy include, among other things: developing, retaining and attracting a diverse and skilled workforce, providing opportunities for continuous learning, development, career growth, and movement within the Company, supporting and rewarding our employees through competitive pay and benefits, encouraging and supporting a community-minded Company culture, and investing in the physical, emotional and financial health and safety of our employees. The following is an overview of some of our key human capital initiatives intended to foster the overall well-being of our employees and other stakeholders, such as our customers and business partners. Equity, Inclusion and Diversity We strive to create a workplace culture that values trust and respect. Our culture guides our overall commitment to doing what is right, offering all employees the opportunity to enrich their lives and careers through challenging and meaningful work in an equal opportunity workplace surrounded by a supportive and inclusive environment. Foundational to this culture is active AVISTA CORPORATION engagement with and listening to our employees, customers and communities in order to help measure and inform our equity, inclusion, diversity, and racial and social justice practices. Our equity, inclusion, and diversity (EID) initiatives are focused on equity in our systems, employee recruitment, employee training and development, and employee engagement, including participation in employee resource groups. Employee resource groups are voluntary, employee-led groups that foster a diverse and inclusive workplace aligned with our organizational mission, values and goals and business practices. We sponsored four employee resource groups in 2022: Women of Avista, Veterans of Avista, Diversity Awareness, and Connections. Additional employee-focused EID efforts include active engagement in employment system and practice reviews to uncover and correct systemic inequities and/or barriers for a more fulsome approach to EID. Projects include overhauling and updating all job descriptions ensuring equity among similar positions regardless of the department, a pay equity project and developing a robust inclusive recruiting initiative to address direct recruiting activities and processes, recruiting systems and future workforce pipeline development. On December 31, 2022, Avista Utilities employed 1,767 with an employee profile of:

##TABLE_START Women Under-Represented Groups (a) Bargaining Unit 3% 6% Non-bargaining Unit 44% 10% Executives (b) 14% 7% Overall 30% 9% ##TABLE_END (a) As defined by our Affirmative Action Plan and through employee self-identification. (b) Executive is defined as vice president or higher. Employee data represents all regular full-time and part-time employees, including temporary workers and student interns. Bargaining Unit employees comprise 36 percent of Avista Utilities employees. People Development, Retention and Attraction We strive to hire and retain talented people who are innovative and skilled so that we can continue to provide safe, reliable and affordable service to our customers and advance our Company at the same time. Retention of our talented people is a focal strategy addressed through employee engagement efforts and the pay equity project. In 2022, we held our biennial employee experience survey and established an Employee Experience Core Team to prioritize initiatives focusing on enhancing our employee experience. Continuous learning fosters collaboration and innovation among our employees and is embedded throughout the Company. Development opportunities are created to increase skill strength and prepare our employees at all levels to ensure they have the skills, knowledge and experience to perform today and well into the future. Keeping our workforce equipped to succeed is imperative in order to meet the emerging challenges that lay ahead. We develop training that is relevant, necessary and in demand for our organization. Training is delivered through instructor-led courses, self-service topics, computer-based learning modules, and field-based, hands-on workshop models that cover the range of our operations. Training programs include craft apprenticeship programs, engineering development programs, leadership development, communication skills, cross-functional learning and EID topics. We also provide opportunities for our employees to attend industry events and certification programs, courses or programs offered through energy-related organizations such as the Western Energy Institute, the American Gas Association and the Edison Electric Institute, as well as through our local colleges and universities. Workplace Safety Safety is an essential part of our mission. A variety of programs and initiatives are in place to help employees complete their work safely through heightened vigilance, hazard recognition, defensive strategies, lessons learned, human and organizational performance and other tools intended to ensure resilience in varying and unpredictable conditions. We work with our employees to reinforce personal responsibility regarding safety and health, and to implement measures to create and maintain a safe work environment. AVISTA CORPORATION Additional Information Additional information highlighting the Company's commitments to corporate responsibility, including the Companys commitments to our environment, our people, our customers and communities and ethical governance, is available on the Companys website at www.avistacorp.com. Material on the Companys website is not part of this report. AVISTA U TILITIES Gene ral At the end of 2022, Avista Utilities supplied retail electric service to approximately 411,000 customers and retail natural gas service to approximately 377,000 customers across its service territory. Avista Utilities' service territory covers 30,000 square miles with a population of 1.7 million. See Item 2.

Properties for further information on our utility assets. See Item 7. Managements Discussion and Analysis of Financial Condition and Results of Operations Economic Conditions and Utility Load Growth for information on economic conditions in our service territory. Electric O perations General Avista Utilities generates, transmits and distributes electricity, serving electric customers in eastern Washington and northern Idaho and a small number of customers in Montana, most of whom are employees who operate Avista Utilities' Noxon Rapids generating facility. Avista Utilities generates electricity from facilities that we own and purchases capacity, energy and fuel for generation under long-term and short-term contracts to meet customer load obligations. We also sell electric capacity and energy, as well as surplus fuel in the wholesale market in connection with our resource optimization activities as described below. As part of Avista Utilities' resource procurement and management operations in the electric business, we engage in an ongoing process of resource optimization, which involves the selection from available energy resources to serve our load obligations and the use of these resources to capture economic value through wholesale market transactions. These include sales and purchases of electric capacity and energy, fuel for electric generation, and derivative contracts related to capacity, energy, fuel and fuel transportation. Such transactions are part of the process of matching available resources with load obligations and hedging a portion of the related financial risks. In order to implement this process, we make continuing projections of: electric loads at various points in time (ranging from intra-hour to multiple years) based on, among other things, estimates of customer usage and weather, historical data, contract terms, and emerging trends and climate modeling results, and resource availability at these points in time based on, among other things, fuel choices and fuel markets, estimates of snowpack and streamflows, availability of generating units, historic and forward market information, contract terms and experience. On the basis of these projections, we make purchases and sales of electric capacity and energy, fuel for electric generation, and related derivative contracts to match expected resources to expected electric load requirements and reduce our exposure to electricity (or fuel) market price changes. The process of resource optimization involves scheduling and dispatching available resources as well as the following: purchasing fuel for generation, when economical, selling fuel and substituting wholesale electric purchases, and other wholesale transactions to capture the value of generating resources, transmission contract rights and fuel delivery (transport) capacity contracts. This optimization process includes entering into hedging transactions to manage risks. Transactions include both physical energy contracts and related derivative instruments, and the terms range from intra-hour up to multiple years. AVISTA CORPORATION Avista Utilities' generation assets are interconnected through the regional transmission system and are operated on a coordinated basis to enhance load-serving capability and reliability. We acquire both long-term and short-term transmission capacity to facilitate all of our energy and capacity transactions. We provide transmission and ancillary services in eastern Washington, northern Idaho and western Montana. Electric Re quirements Avista

Utilities' peak electric native load requirement for 2022 was 1,860 MW, which occurred on December 22, 2022. In 2021, our peak electric native load was 1,889 MW, which occurred during the summer, and in 2020, it was 1,721 MW, which occurred during the summer. Electric Resources Avista Utilities has a diverse electric resource mix of Company-owned and contracted hydroelectric, thermal and wind generation facilities, and other contracts for power purchases and exchanges. As of December 31, 2022, Avista Utilities' electric generation resource mix (including contracts for power purchases) was approximately 48 percent hydroelectric, 43 percent thermal and 9 percent other renewables. See Item 2. Properties for detailed information on Company-owned generating facilities. Hydroelectric Resources Avista Utilities owns and operates Noxon Rapids and Cabinet Gorge on the Clark Fork River and six smaller hydroelectric projects on the Spokane River. Hydroelectric generation is typically our lowest cost source per MWh of electric energy and the availability of hydroelectric generation has a significant effect on total power supply costs. Under normal streamflow and operating conditions, we estimate that we would be able to meet approximately one-half of our total average electric requirements (both retail and long-term wholesale) with the combination of our hydroelectric generation and long-term hydroelectric purchase contracts with certain PUDs in the state of Washington. Our estimate of normal annual hydroelectric generation for 2023 (including resources purchased under long-term hydroelectric contracts with certain PUDs) is 573.5 aMW (or 5.0 million MWhs). See Item 2. Properties - Avista Utilities - Generation Properties for the present generating capabilities of the above hydroelectric resources. AVISTA CORPORATION The following graph shows Avista Utilities' hydroelectric generation (in thousands of MWhs) during the year ended December 31: (1) Normal hydroelectric generation is determined by reference to the effect of upstream dam regulation on median natural water flow. Natural water flow is the flow of the rivers without the influence of dams, whereas regulated water flow takes into account any water flow changes from upstream dams due to releasing or holding back water. The calculation of normal varies annually due to the timing of upstream dam regulation throughout the year, as well as changes in PUD contracts. Thermal Resources Avista Utilities owns the following thermal generating resources: the combined cycle natural gas-fired CT, known as Coyote Springs 2, located near Boardman, Oregon, a 15 percent interest in Units 3 and 4 of Colstrip, a coal-fired boiler generating facility located in southeastern Montana. We have an agreement with NorthWestern to transfer our ownership at the end of 2025; see Note 22 of the Notes to Consolidated Financial Statements for discussion of our Colstrip transaction with NorthWestern, a wood waste-fired boiler generating facility known as the Kettle Falls GS in northeastern Washington, a two-unit natural gas-fired CT generating facility in northeastern Spokane (Northeast CT), a two-unit natural gas-fired CT generating facility in northern Idaho (Rathdrum CT), and two small natural gas-fired generating facilities (Boulder Park GS and Kettle Falls CT). Coyote Springs 2, which is operated by Portland General Electric Company, is supplied with natural gas under a combination of term contracts and spot market purchases, including transportation agreements with bilateral renewal rights. Colstrip, which is operated by Talen Montana, is supplied with fuel from adjacent coal reserves under coal supply and transportation agreements. Several of the co-owners of Colstrip, including us, have a coal contract that runs through December AVISTA CORPORATION 31, 2025. See Item 7. Management's Discussion and Analysis Colstrip for discussion regarding environmental and other issues surrounding Colstrip. The primary fuel for the Kettle Falls GS is wood waste generated as a by-product and delivered by trucks from forest industry operations within 100 miles of the plant. A combination of long-term contracts and spot purchases has provided, and is expected to meet, fuel requirements for the Kettle Falls GS. The Northeast CT, Rathdrum CT, Boulder Park GS and Kettle Falls CT generating units are primarily used to meet peaking electric requirements. We also operate these facilities when marginal costs are below prevailing wholesale electric prices. These generating facilities have access to natural gas supplies that are adequate to meet their respective operating needs. See Item 2. Properties - Avista Utilities - Generation Properties for the present generating capabilities of the above thermal resources. The Lancaster Plant is a 270 MW natural gas-fired combined cycle combustion turbine plant located in northern Idaho, owned by an unrelated third-party. All of the output from the Lancaster Plant is contracted to us through October 31, 2026 under a PPA. Under the terms of the PPA, we make the dispatch decisions, provide all natural gas fuel and receive all of the electric energy output. Therefore, we consider the Lancaster Plant to be a baseload resource. See Note 6 of the Notes to Consolidated Financial Statements for further discussion of this PPA. The following graph shows Avista Utilities' thermal generation (in thousands of MWhs) during the year ended December 31: Wind Resources We have exclusive rights to all the capacity of Palouse Wind, a wind generation project developed, owned and managed by an unrelated third-party and located in Whitman County, Washington. The PPA expires in 2042 and requires us to acquire all of the power and renewable attributes produced by the project at a fixed price per MWh with a fixed escalation of the price over the term of the agreement. The project has a nameplate capacity of 105 MW. Generation from Palouse Wind was 315,410 MWhs in 2022, 360,783 MWhs in 2021 and 370,142 MWhs in 2020. We have an annual option to purchase the wind project, which we have not exercised. The purchase price is a fixed price per KW of in-service capacity with a fixed decline in the price per KW over the remaining 20-year term of the PPA. Under the terms of the PPA, we do not have any input into the day-to-day operation of the project, including maintenance decisions. All such rights are held by the owner. AVISTA CORPORATION We have exclusive rights to all of the capacity of Rattlesnake Flat Wind project developed, owned and managed by an unrelated third party and located in Adams County, Washington. The facility has a nameplate capacity of 144 MW. The PPA is a 20-year agreement that began in December 2020 and requires us to acquire all of the power and renewable attributes produced by the project at a fixed price per MWh with a fixed escalation of the price over the term of the agreement. Generation from Rattlesnake Flat Wind was 363,533 MWhs in 2022 and 423,510 MWhs in 2021. Under the terms of the PPA, we do not have any input into the day-to-day operation of the project, including maintenance decisions. All such rights are held by the owner. Solar Resources We have exclusive rights to all the capacity of the Lind Solar Farm, a solar generation project developed, owned and managed by an unrelated third-party and located in Lind, Washington. The PPA expires in 2038 and requires us to acquire all the power and renewable attributes produced by the project at a fixed price per MWh. The project has a nameplate capacity of 28 MW. The facility generated 34,809 MWhs in 2022, 43,328 MWhs in 2021, and 45,281 MWhs in 2020. Under the terms of the PPA, we do not have any input into the day-to-day operation of the project, including maintenance decisions. All such rights are held by the owner. Other Purchases, Exchanges and Sales In addition to the resources described above, we purchase and sell power under various long-term contracts, and we also enter into short-term purchases and sales. Further, pursuant to The Public Utility Regulatory Policies Act of 1978, as amended, we are required to purchase generation from qualifying facilities. This includes, among other resources, hydroelectric projects, cogeneration projects and wind generation projects at rates approved by the WUTC and the IPUC. See Avista Utilities Electric Operating Statistics Electric Operations below for annual quantities of purchased power, wholesale power sales and power from exchanges in 2022, 2021 and 2020. See Electric Operations above for additional information with respect to the use of wholesale purchases and sales as part of our resource optimization process and also see Future Resource Needs below for the magnitude of these power purchase and sales contracts in future periods. Avista Corp. understands that there are many coal-fired electric generating stations throughout the western United States that are scheduled for retirement in the next several years. Depending upon a variety of factors, these retirements could have an impact upon the availability and price of purchased power in, and the dynamics of, the market in which we conduct our wholesale purchases and sales. After December 31, 2025, we are prohibited by Clean Energy Transformation Act (CETA) from using energy produced by coal-fired plants to serve our retail customers in Washington. In order to comply, we entered into an agreement with NorthWestern to transfer our interest in Colstrip at the end of 2025. To the extent necessary, we will obtain energy produced by other resources. See Item 7. Management's Discussion and Analysis Environmental Matters and Contingencies Climate Change Washington Legislation and Regulatory Actions Clean Energy Transformation Act and Colstrip. Hydroelectri c Licenses Avista Corp. is a licensee under the Federal Power Act (FPA) as administered by the FERC, which includes regulation of hydroelectric generation resources. Excluding the Little Falls Hydroelectric Generating Project (Little Falls), our other seven hydroelectric plants are regulated by the FERC through two project licenses. The licensed projects are subject to the provisions of Part I of the FPA. These provisions include payment for headwater benefits, condemnation of licensed projects upon payment of just compensation, and take-over by the federal government of such projects after the expiration of the license upon payment of the lesser of net investment or fair value of the project, in either case, plus severance damages. In the unlikely event that a take-over occurs, it could lead to either the decommissioning of the hydroelectric project or offering the project to another party (likely through sale and transfer of the license). Cabinet Gorge and Noxon Rapids are under one 45-year FERC license expiring in 2046. This license embodies a settlement agreement relating to project operations and resource protection and mitigation efforts over the license term. See Item 7. Management's Discussion and Analysis Environmental Issues and Contingencies for discussion of dissolved atmospheric gas levels that exceed the state of Idaho and federal numeric water quality standards downstream of Cabinet Gorge during AVISTA CORPORATION periods when we must divert excess river flows over the spillway, as well as efforts related to bull trout, a threatened species under the Endangered Species Act. Five of our six hydroelectric projects on the Spokane River (Long Lake, Nine Mile, Upper Falls, Monroe Street and Post Falls) are under one 50-year FERC license expiring in 2059 and are referred to collectively as the Spokane River Project. The license includes numerous natural and cultural resource protection measures that are subject to ongoing regulatory interpretation. The sixth, Little Falls, is operated under separate Congressional authority and is not licensed by the FERC. It is the subject of a 50-year agreement with the Spokane Tribe, signed in 1994. Future Reso urce Needs Avista Utilities has operational strategies to provide sufficient resources to meet our energy requirements under a range of operating conditions. These operational strategies consider the amount of energy needed, which varies widely because of the factors that influence demand over intra-hour, hourly, daily, monthly and annual durations. Our average hourly load was 1,142 aMW in 2022, 1,113 aMW in 2021 and 1,064 aMW in 2020. The following graph shows our forecast of our average annual energy requirements and our available resources for 2023 through 2026: (1) The combined maximum capacity of Boulder Park GS, Kettle Falls CT, Northeast CT and Rathdrum CT is 278 MW, with estimated available energy production as indicated for each year. (2) Other contracts for power purchases includes power purchase agreements for solar and wind energy. (3) The forecast assumes near normal hydroelectric generation. (4) Includes the Lancaster Plant PPA (current PPA through October 31, 2026). Excludes Boulder Park GS, Kettle Falls CT, Northeast CT and Rathdrum CT, as these are considered peaking facilities and are generally not used to meet our base load requirements. We are required to file an Integrated Resource Plan (IRP) or Washington Progress Report with the WUTC and IPUC every two years. The WUTC and IPUC review the IRP and give the public the opportunity to comment. The WUTC and IPUC do not approve or disapprove of the content in the IRP; rather, they acknowledge that the IRP was prepared in accordance with applicable standards if that is the case. The IRP details projected growth in demand for energy and the new resources needed to AVISTA CORPORATION serve customers over the next 20 years. We regard the IRP as a tool for resource evaluation, rather than an acquisition plan for a particular project. In April 2021, we filed our 2021 Electric IRP with the WUTC and the IPUC. Later that same month, we filed an amended Electric IRP to include the results of the 2020 Renewable Request for Proposal (RFP). We plan to file the 2023 Electric IRP in June 2023. Highlights of the amended 2021

Electric IRP include the following expectations and/or assumptions: We have adequate resources between owned and contractually controlled generation, when combined with conservation and market purchases, to meet customer demand through October 2026. Our first long-term capacity deficit, net of energy efficiency, begins in October 2026 and is 247 MW by January 2027. New renewable energy, energy storage, demand response, energy efficiency, and upgrades to existing hydropower and biomass plants are integral to our plan. We anticipate customer load growth of 0.3 percent per year. Assumes Colstrip will exit the portfolio by 2025 (see Item 7. Managements Discussion and Analysis of Financial Condition Environmental Issues and Contingencies and Note 22 of the Notes to Consolidated Financial Statements for further discussion of Colstrip in relation to the Washington CETA). New natural gas-fired peaking units are the most economic means to meet the capacity shortfall in 2027 since long-term energy storage is not yet available at a cost effective price. Demand response programs begin in 2025 and grow to 72 MW by 2045. Our first new renewable resource identified in the IRP is in 2025, as a wind project located in Montana. Actual resource selection will be determined by a future RFP. The resource strategy embodied in the IRP is intended to move us closer to achieving our corporate clean electricity goal to provide customers with 100 percent net clean electricity by 2027. Net clean energy is defined as either 100 percent non-carbon emitting resources or investing in or acquiring carbon offsets to net-out emissions created from carbon emitting resources. The addition of natural gas peaking units in 2027 would require us to purchase carbon offsets to obtain our net clean electricity goal. We are subject to the Washington State Energy Independence Act, which requires us to obtain a portion of our electricity from qualifying renewable resources or through purchase of RECs and acquiring all cost effective conservation measures. Future generation resource decisions will be affected by legislation for restrictions on greenhouse gas emissions and renewable energy requirements. See Item 7. Managements Discussion and Analysis of Financial Condition Environmental Issues and Contingencies and Colstrip for information related to existing and proposed laws and regulations, and issues relating to Colstrip. Additional generating resources that we will require will either be owned by us or be owned by other parties who will sell the capacity and energy to us under PPAs. The decision as to ownership will be made as to each project at the appropriate time and will depend on, among other things, the type of project and the related economics, including tax and ratemaking treatment. Request for Proposal for Energy and Capacity In February 2022, we issued an All-Source Request for Proposal from energy project owners and developers, seeking approximately 196 MWs of winter capacity and 190 MWs of summer capacity. After reviewing the bids received, several projects were selected for further contract negotiations. Contracts already signed include a 23 year PPA for 145 MWs peak from seven irrigation hydro generation projects that will ramp in between 2023 and 2030 and a 30 year PPA for 98 MWs of wind starting in 2026. Negotiations for additional PPAs are on-going. AVISTA CORPORATION Clean Energy Goals In April 2019, we announced a goal to serve our customers with 100 percent clean electricity by 2045 and to have a carbon-neutral supply of electricity by the end of 2027. To help achieve our goals and add to our clean electricity portfolio, in the last three years, we have implemented renewable energy projects on behalf of our customers including entering into PPAs for the Solar Select project (28 MW) in Lind, Washington and the Rattlesnake Flat Wind project (144 MW) in Adams County, Washington. We also entered into two power purchase contracts with Chelan County Public Utility District for a percentage share of the output of their Rocky Reach and Rock Island hydro projects for 22 years starting in 2024 (88-264 MW). These resources are in addition to our existing clean hydroelectric generation, biomass generation, and additional wind and solar projects. To achieve our clean energy goals, we expect energy storage and other technologies, which are either not currently available or are not cost-effective under the lowest reasonable cost regulatory standard, will advance such that it will allow us to meet our goals while also maintaining reliability and affordability for our customers. If the required technology is not available or not affordable in the future, we may not meet our goals in the desired timeframe. Meeting our clean energy goals may also require accommodation from regulatory agencies insofar as we may need to acquire emission offsets to meet our goals. See the discussion in Item 1 under Electric Resources for more information on our existing clean electricity sources and efforts to achieve these goals. See Item 7. Managements Discussion and Analysis of Financial Condition Environmental Issues and Contingencies for further discussion on clean energy, including applicable regulations. Wildfire Resiliency Plan We are implementing additional measures to enhance our ability to mitigate the potential for, and impact of, wildfires within our service territories. Building on prevention and response strategies that have been in place for many years, in 2020 we created a comprehensive 10-year Wildfire Resiliency Plan that includes improved defense strategies and operating practices for a more resilient system. This plan will be periodically updated and informed by observed experience as well as changes in observed landscape and climatic conditions. We developed the Wildfire Resiliency Plan through a series of internal workshops, industry research and engagement with state and local fire agencies. Improvements to infrastructure and operational practices were identified as key components to the plan. These key components are categorized into the following categories: grid hardening, vegetation management, situational awareness, operations and emergency response, and worker and public safety. We expect to spend approximately $330 million implementing the plan components over the life of the 10-year plan that began in 2020. The IPUC and WUTC approved deferral of certain costs of the wildfire resiliency plan, and we will seek recovery of those deferred costs in future rate filings. See Note 22 of the Notes to Consolidated Financial Statements for further discussion on wildfires. Natural Gas Operations General Avista Utilities provides natural gas distribution services to retail customers in parts of eastern Washington, northern Idaho, and northeastern and southwestern Oregon. Market prices for natural gas, like other commodities, can be volatile. Our natural gas procurement strategy is to provide a reliable supply to our customers with some level of price certainty. We procure natural gas from various supply basins and over varying time periods. The resulting portfolio is a diversified mix of forward fixed price purchases, index and spot market purchases, and utilizing physical and financial derivative instruments. We also use natural gas storage to support high demand periods and the procurement of natural gas when prices may be lower. Securing prices throughout the year and even into subsequent years provides a level of price certainty and can mitigate price volatility to customers between years. Weather is a key component of our natural gas customer load. This load is highly variable and daily natural gas loads can differ significantly from the monthly forecasted load projections. We make continuing projections of our natural gas loads and assess AVISTA CORPORATION available natural gas resources. On the basis of these projections, we plan and execute a series of transactions to hedge a portion of our customers' projected natural gas requirements through forward market transactions and derivative instruments. These transactions may extend for multiple years into the future. We also leave a portion of our natural gas supply requirements unhedged for purchase in the short-term spot markets. Our purchase of natural gas supply is governed by our procurement plan and is reviewed and approved annually by the Risk Management Committee (RMC), which is comprised of certain officers and other management personnel. Once approval is received, the plan is implemented and monitored by our gas supply and risk management groups. The plans progress is also presented to the WUTC and IPUC staff in semi-annual meetings, and updates are given to the OPUC staff quarterly. The RMC is provided with an update on plan results and changes in their monthly meetings. These activities provide transparency for the natural gas supply procurement plan. Any material changes to the plan are documented and communicated to RMC members. As part of the process of balancing natural gas retail load requirements with resources, we engage in the wholesale purchase and sale of natural gas. We plan for sufficient natural gas delivery capacity to serve our retail customers for a theoretical peak day event. We generally have more pipeline and storage capacity than what is needed during periods other than a peak day. We optimize our natural gas resources by using market opportunities to generate economic value that helps mitigate fixed costs. Wholesale sales are delivered through wholesale market facilities outside of our natural gas distribution system. Natural gas resource optimization activities include, but are not limited to: wholesale market sales of surplus natural gas supplies, purchases and sales of natural gas to optimize use of pipeline and storage capacity, and participation in the transportation capacity release market. We also provide distribution transportation service to qualified, large commercial and industrial natural gas customers who purchase natural gas through third-party marketers. For these customers, we receive their purchased natural gas from such third-party marketers into our distribution system and deliver it to the customers premises. These customers generally pay the same rates as other customers in the same class, without any charge for the cost of the natural gas delivered. Optimization transactions that we engage in throughout the year are included in our annual purchased gas cost adjustment filings with the various commissions and are subject to review for prudence during this process. Clean Energy Goals In April 2021, we announced an aspirational goal to reduce carbon emissions for natural gas 30 percent by 2030 and 100 percent by 2045. Examples of carbon emissions reduction strategies include the following: Diversify or transition from fossil fuel-based natural gas to renewable natural gas, Reduce natural gas consumption via conservation, energy efficiency and new technologies, and Purchase carbon offsets as necessary. Achieving the carbon emission reductions for the natural gas system will involve various pathways. The initial primary pathways include renewable natural gas (RNG), energy efficiency, customer voluntary RNG and carbon offset programs. See Item 7. Managements Discussion and Analysis of Financial Condition Environmental Issues and Contingencies for further discussion on clean energy, including applicable regulations. Natural Gas Supply Avista Utilities purchases all of its natural gas in wholesale markets. We are connected to multiple supply basins in the western United States and Canada through firm capacity transportation rights on six different pipeline networks. Access to this diverse portfolio of natural gas resources allows us to make natural gas procurement decisions that benefit our natural gas customers. AVISTA CORPORATION These interstate pipeline transportation rights provide the capacity to serve approximately 25 percent of peak natural gas customer demands from domestic sources and 75 percent from Canadian sourced supply. Natural gas prices in the Pacific Northwest are affected by global energy markets, as well as supply and demand factors in other regions of the United States and Canada. Future prices and delivery constraints may cause our resource mix to vary. Natural Gas Storage Avista Utilities owns a one-third interest in Jackson Prairie, an underground aquifer natural gas storage field located near Chehalis, Washington. Jackson Prairie has a total peak day deliverability of 12 million therms, with a total working natural gas capacity of 256 million therms. As an owner, our share is one-third of the peak day deliverability and total working capacity. We also contract for additional storage capacity and delivery at Jackson Prairie from Northwest Pipeline for a portion of their one-third share of the storage project. We optimize our natural gas storage capacity throughout the year by executing transactions that capture favorable market price spreads. Natural gas buyers identify opportunities to purchase lower cost natural gas in the immediate term to inject into storage, and then sell the gas in a forward market to be withdrawn at a later time. The reverse of this type of transaction also occurs. These transactions lock in incremental value for customers. Jackson Prairie is also used as a variable peaking resource, and to protect from extreme daily price volatility during cold weather or other events affecting the market. See Executive Level Summary for discussion on market volatility in December 2022 and the impacts to our business. Future Resource Needs In April 2021, we filed our 2021 Natural Gas IRP with the WUTC, the IPUC and the OPUC. The IRP details projected growth in demand for energy and the new resources needed to serve customers over the next 20 years. We regard the IRP as a tool for resource evaluation, rather than an acquisition plan for a particular project. The IPUC and OPUC have formally acknowledged our IRP; the WUTC is still processing the IRP. Highlights of the

2021 natural gas IRP include the following expectations and/or assumptions: We anticipate having sufficient natural gas resources during the 20-year planning horizon. Due to expected carbon legislation at the state levels through a cap and reduce mechanism (Oregon) and a cap and invest mechanism (Washington), we expect our retail natural gas rates to include a carbon price adder in Oregon and Washington, but not in Idaho. Regional supply constraints are beginning to increase in their likelihood causing prices to act in a more volatile fashion. This volatility in pricing paired with supply side resource availability has made our procurement plan an increasingly important piece to manage customer rates, diversity of supply and peak day demand. Liquefied natural gas exports, power generation and exports to Mexico will continue to add demand for natural gas. We expect lower use per customer and an increased amount of demand side management (DSM). The combination of low-priced natural gas in addition to carbon fees or other programs has led to a higher potential for DSM measures. We view renewable natural gas and low carbon fuels as an important component of our corporate environment strategy and decarbonization goals. We will monitor these assumptions on an on-going basis and adjust our resource requirements accordingly. We are required to file a natural gas IRP every two years and we anticipate our next IRP to be filed in April 2023. Request for Proposals for Renewable Natural Gas Resources In October 2022, we issued a Request for Proposals seeking renewable natural gas resources for our customers over the long term to reach aspirational goals to reduce emissions and comply with local regulations. See Item 7. Managements Discussion AVISTA CORPORATION and Analysis of Financial Condition Environmental Issues and Contingencies for further discussion on clean energy, including applicable regulations. Bids in response to the Request for Proposal were submitted through December 2022. We are evaluating bids. Utility Regulation General As a public utility, Avista Corp. is subject to regulation by state utility commissions for retail electric and natural gas rates, accounting, the issuance of securities and other matters. The retail electric and natural gas operations are subject to the jurisdiction of the WUTC, IPUC, OPUC and MPSC. Approval of the issuance of securities is not required from the MPSC. We are also subject to the jurisdiction of the FERC for licensing of hydroelectric generation resources, and for electric transmission services and wholesale sales. Since Avista Corp. is a holding company (in addition to being itself an operating utility), we are also subject to the jurisdiction of the FERC under the Public Utility Holding Company Act of 2005, which imposes certain reporting and record-keeping requirements on Avista Corp. and its subsidiaries. We and our subsidiaries are required to make books and records available to the FERC and the state utility commissions. In addition, upon the request of any jurisdictional state utility commission, the FERC would have the authority to review assignment of costs of non-power goods and administrative services among us and our subsidiaries. The FERC has the authority generally to require that rates subject to its jurisdiction be just and reasonable and in this context would continue to be able to, among other things, review transactions of an affiliated company. Our rates for retail electric and natural gas services (other than specially negotiated retail rates for industrial or large commercial customers, which are subject to regulatory review and approval) are generally determined on a cost of service basis. Retail rates are designed to provide an opportunity to recover allowable operating expenses and earn a return of and a reasonable return on rate base. Rate base is generally determined by reference to the original cost (net of accumulated depreciation) of utility plant in service, subject to various adjustments for deferred income taxes and other items. Over time, rate base is increased by additions to utility plant in service and reduced by depreciation and write-offs as authorized by the utility commissions. Our operating expenses and rate base are allocated or directly assigned to five regulatory jurisdictions: electric in Washington and Idaho, and natural gas in Washington, Idaho and Oregon. In general, requests for new retail rates are made on the basis of revenues, operating expenses and net investment for a test year that ended prior to the date of the request, subject to possible adjustments, which differ among the various jurisdictions, designed to reflect the expected revenues, operating expenses and net investment during the period new retail rates will be in effect. The retail rates approved by the state commissions in a rate proceeding may not provide sufficient revenues to provide recovery of costs and a reasonable return on investment for a number of reasons, including, but not limited to, ongoing capital expenditures and unexpected changes in revenues and expenses following the time new retail rates are requested in the rate proceeding (known as regulatory lag), the denial by the commission of recovery, or timely recovery, of certain expenses or investment and the limitation by the commission of the authorized return on investment. In 2021, Washington enacted a multi-year rate plan and performance-based rate making regulations, and our 2022 general rate cases were our first filed under these new regulations. See Item 7. Managements Discussion and Analysis Regulatory Matters General Rate Cases for further information. Our rates for wholesale electric sales and electric transmission services, as well as certain natural gas transportation services, are based on either cost of service principles or market-based rates as set forth by the FERC. See Notes 1, 13 and 23 of the Notes to Consolidated Financial Statements for additional information about regulation, depreciation and deferred income taxes. General Rate Cases Avista Utilities regularly reviews the need for electric and natural gas rate changes in each state in which we provide service. See Item 7. Managements Discussion and Analysis Regulatory Matters General Rate Cases for information on general rate case activity. AVISTA CORPORATION Power Cost Deferrals Avista Utilities defers the recognition in the income statement of certain power supply costs that vary from the level currently recovered from our retail customers as authorized by the WUTC and the IPUC. See Item 7. Managements Discussion and Analysis Regulatory Matters Power Cost Deferrals and Recovery Mechanisms and Note 23 of the Notes to Consolidated Financial Statements for information on power cost deferrals and recovery mechanisms. Purchased Gas Adjustments (PGA) Under established regulatory practices in each state, Avista Utilities defers the recognition in the income statement of the natural gas costs that vary from the level currently recovered from our retail customers as authorized by each of our jurisdictions. See Item 7. Managements Discussion and Analysis Regulatory Matters Purchased Gas Adjustments and Note 23 of the Notes to Consolidated Financial Statements for information on natural gas cost deferrals and recovery mechanisms. Decoupling Mechanisms Decoupling (also known as FCA in Idaho) is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. In each of its jurisdictions, Avista Utilities' electric and natural gas revenues are adjusted so as to be based on the number of customers in certain customer rate classes and assumed normal usage, rather than being based on actual usage. The difference between revenues based on the number of customers and normal sales and revenues based on actual usage is deferred and either surcharged or rebated to customers beginning in the following year. See Item 7. Managements Discussion and Analysis Regulatory Matters Decoupling and Earnings Sharing Mechanisms and Note 23 of the Notes to Consolidated Financial Statements for further discussion of these mechanisms. Federal Laws Related to Wholesale Competition Federal law promotes practices that foster competition in the electric wholesale energy market. The FERC requires electric utilities to transmit power and energy to or for wholesale purchasers and sellers, and requires electric utilities to enhance or construct transmission facilities to create additional transmission capacity for the purpose of providing these services. Public utilities (through subsidiaries or affiliates) and other entities may participate in the development of independent electric generating plants for sales to wholesale customers. Public utilities operating under the FPA are required to provide open and non-discriminatory access to their transmission systems to third parties and establish an Open Access Same-Time Information System to provide an electronic means by which transmission customers can obtain information about available transmission capacity and purchase transmission access. The FERC also requires each public utility subject to the rules to operate its transmission and wholesale power merchant operating functions separately and to comply with standards of conduct designed to ensure that all wholesale users, including the public utilitys power merchant operations, have equal access to the public utilitys transmission system. Our compliance with these standards has not had any substantive impact on the operation, maintenance and marketing of our transmission system or our ability to provide service to customers. See Item 7. Managements Discussion and Analysis Competition for further information. Regional Transm ission Planning Beginning with FERC Order No. 888 and continuing with subsequent rulemakings and policies, the FERC has encouraged better coordination and operational consistency aimed to capture efficiencies that might otherwise be gained through the formation of a Regional Transmission Organization or an independent system operator (ISO). The Company meets its FERC requirements to coordinate transmission planning activities with other regional entities through NorthernGrid. Launched January 1, 2020, NorthernGrid is an association of all major transmission providers throughout the Pacific Northwest and Intermountain West, with facilities in California, Idaho, Montana, Oregon, Utah, Washington and Wyoming. Through its participation in NorthernGrid, the Company is able to meet the regional transmission planning requirements of FERC Order Nos. 890 and 1000, and their follow-on orders. NorthernGrid and its members also work with AVISTA CORPORATION other western organizations, including WestConnect and the California Independent System Operator (CAISO), to address broader interregional planning. Neither the costs nor requirements of participating in NorthernGrids coordinated transmission planning activities are expected to materially impact the Companys operations or financial performance. Regional Ene rgy Markets The CAISO operates the Western Energy Imbalance Market (EIM) in the western United States. Most investor-owned utilities in the Pacific Northwest are either participants in the Western EIM or plan to integrate into the market in the near future. The Company commenced Western EIM operations in March 2022. The decision to join the Western EIM was based on a number of factors, including the amount of expected variable generating resources the Company will need to integrate within its balancing authority area in the foreseeable future, and the expected costs and benefits associated with joining the Western EIM. The Western EIM, among other things, facilitates regional load balancing by allowing certain generating plants to receive automated dispatch signals from the CAISO in five-minute intervals. Reliability Standards Among its other provisions, the U.S. Energy Policy Act provides for the implementation of mandatory reliability standards and authorizes the FERC to assess penalties for non-compliance with these standards and other FERC regulations. The FERC certified the NERC as the single Electric Reliability Organization authorized to establish and enforce reliability standards and delegate authority to regional entities for the purpose of establishing and enforcing reliability standards, including but not limited to cybersecurity measures. The FERC approves NERC Reliability Standards, including western region standards that make up the set of legally enforceable standards for the United States bulk electric system. We are required to self-certify our compliance with these standards on an annual basis and undergo regularly scheduled periodic reviews by the NERC and its regional entity, the Western Electricity Coordinating Council (WECC). Failure to comply with NERC reliability standards could result in substantial financial penalties. We have a robust internal compliance program in place to manage compliance activities and mitigate the risk of potential noncompliance with these standards. We do not expect the costs associated with compliance with these standards to have a material impact on our financial results. As both a balancing authority and transmission operator, the Company must operate under the oversight of a reliability coordinator per NERC reliability standards. RC West is the reliability coordinator of record for 41 balancing authorities and transmission operators in the Western Interconnection, including Avista Corp. RC West oversees grid compliance with federal and regional grid standards, and can determine measures to prevent or mitigate system emergencies in day-ahead or real-time operations. Vulnerability to Cyberattack The energy sector, including electric and natural gas utility companies in the United States and abroad, have become the subject of cyberattacks and ransomware attacks with increased frequency. The Companys administrative and operating networks are targeted by hackers on a regular basis. A successful attack on the Companys administrative networks could compromise the security and privacy of data, including operating, financial and personal information. A successful attack on the Companys operating networks could impair the operation of the Companys electric and/or natural gas utility facilities, possibly resulting in the inability to provide electric and/or natural gas service for extended periods of time. The Company continually reinforces and updates its defensive systems and is in compliance with the NERCs reliability standards. See Reliability Standards, Item 1A. Risk Factors Cyber and Technology Risk Factors and Item 7. Managements Discussion and Analysis of Financial Condition and Results of Operations Enterprise Risk Management Cyber and Technology Risks for further information. AVISTA CORPORATION AVISTA U TILITIES ELECTRIC OPERATING STATISTICS ##TABLE_START Years Ended December 31, ELECTRIC OPERATIONS OPERATING REVENUES (Dollars in Thousands): Residential $ 414,823 $ 394,717 $ 377,785 Commercial 338,656 326,173 303,972 Industrial 107,740 106,756 103,103 Public street and highway lighting 7,483 7,472 7,303 Total retail 868,702 835,118 792,163 Wholesale 179,316 89,768 77,277 Sales of fuel 84,256 63,673 28,773 Other 46,319 36,288 30,149 Alternative revenue programs (31,844) (19,525) (4,361) Deferrals and amortizations for rate refunds to customers 1,730 3,539 Total electric operating revenues $ 1,146,823 $ 1,007,052 $ 927,540 ENERGY SALES (Thousands of MWhs): Residential 4,154 3,955 3,807 Commercial 3,201 3,158 2,995 Industrial 1,699 1,666 1,615 Public street and highway lighting Total retail 9,071 8,796 8,435 Wholesale 3,094 2,461 2,680 Total electric energy sales 12,165 11,257 11,115 ENERGY RESOURCES (Thousands of MWhs): Hydro generation (from Company facilities) 3,930 3,598 3,651 Thermal generation (from Company facilities) 4,055 3,635 3,474 Purchased power 5,065 4,954 4,922 Power exchanges (385) (398) (446) Total power resources 12,665 11,789 11,601 Energy losses and Company use (500) (532) (486) Total energy resources (net of losses) 12,165 11,257 11,115 NUMBER OF RETAIL CUSTOMERS (Average for Period): Residential 361,564 356,387 350,669 Commercial 44,550 44,110 43,497 Industrial 1,193 1,205 1,277 Public street and highway lighting Total electric retail customers 407,988 402,368 396,082 RESIDENTIAL SERVICE AVERAGES: Annual use per customer (KWh) 11,487 11,098 10,857 Revenue per KWh (in cents) 9.99 9.98 9.92 Annual revenue per customer $ 1,147.17 $ 1,107.55 $ 1,077.33 AVERAGE HOURLY LOAD (aMW) 1,142 1,113 1,064 ##TABLE_END AVISTA CORPORATION AVISTA UTILITIES ELECTRIC OPERATING STATISTICS ##TABLE_START Years Ended December 31, RETAIL NATIVE LOAD at time of system peak (MW): Winter 1,860 1,696 1,613 Summer 1,810 1,889 1,721 COOLING DEGREE DAYS: (1) Spokane, WA Actual Historical average % of average % % % HEATING DEGREE DAYS: (2) Spokane, WA Actual 6,811 6,124 6,187 Historical average 6,560 6,596 6,651 % of average % % % ##TABLE_END (1) Cooling degree days are the measure of the warmness of weather experienced, based on the extent to which the average of high and low temperatures for a day exceeds 65 degrees Fahrenheit (annual degree days above historical average indicate warmer than average temperatures). (2) Heating degree days are the measure of the coldness of weather experienced, based on the extent to which the average of high and low temperatures for a day falls below 65 degrees Fahrenheit (annual degree days below historical averages indicate warmer than average temperatures). AVISTA CORPORATION AVISTA UTILITIES NATURAL GAS OPERATING STATISTICS ##TABLE_START Years Ended December 31, NATURAL GAS OPERATIONS OPERATING REVENUES (Dollars in Thousands): Residential $ 284,452 $ 221,405 $ 213,612 Commercial 139,923 100,819 94,937 Interruptible 6,474 4,781 4,285 Industrial 3,997 3,015 2,843 Total retail 434,846 330,020 315,677 Wholesale 133,235 113,277 104,910 Transportation 8,627 8,547 7,917 Other 8,156 7,325 5,034 Alternative revenue programs (1,513) 12,890 Deferrals and amortizations for rate refunds to customers 1,254 1,797 Total natural gas operating revenues $ 583,485 $ 473,313 $ 435,882 THERMS DELIVERED (Thousands of Therms): Residential 242,452 219,835 219,988 Commercial 147,059 130,399 127,659 Interruptible 14,166 16,013 14,854 Industrial 5,606 5,402 5,424 Total retail 409,283 371,649 367,925 Wholesale 280,154 356,891 542,372 Transportation 171,785 172,260 180,361 Interdepartmental and Company use Total therms delivered 861,840 901,279 1,091,027 NUMBER OF RETAIL CUSTOMERS (Average for Period): Residential 337,073 332,187 327,125 Commercial 36,753 36,448 36,164 Interruptible Industrial Total natural gas retail customers 374,058 368,867 363,554 RESIDENTIAL SERVICE AVERAGES: Annual use per customer (therms) Revenue per therm (in dollars) $ 1.17 $ 1.01 $ 0.97 Annual revenue per customer $ 843.88 $ 666.51 $ 653.00 HEATING DEGREE DAYS: (1) Spokane, WA Actual 6,811 6,124 6,187 Historical average 6,560 6,596 6,651 % of average % % % Medford, OR Actual 4,408 4,107 4,181 Historical average 4,248 4,254 4,281 % of average % % % ##TABLE_END (1) Heating degree days are the measure of the coldness of weather experienced, based on the extent to which the average of high and low temperatures for a day falls below 65 degrees Fahrenheit (annual degree days below historic indicate warmer than average temperatures). ALASKA ELECTRIC LIGH T AND POWER COMPANY AELP is the primary operating subsidiary of AERC, and the sole utility providing electrical energy in Juneau, Alaska. Juneau is a geographically isolated community with no electric interconnections with the transmission facilities of other utilities and no pipeline access to natural gas or other fuels. Juneaus economy is primarily driven by government activities, tourism, commercial fishing, and mining, as well as activities as the commercial hub of southeast Alaska. AVISTA CORPORATION AELP owns and operates electric generation, transmission and distribution facilities located in Juneau. AELP operates five hydroelectric generation facilities with 102.7 MW of hydroelectric generation capacity. AELP owns four of these generation facilities (totaling 24.5 MW of capacity) and has a PPA for the entire output of the Snettisham hydroelectric project (totaling 78.2 MW of capacity). The Snettisham hydroelectric project is owned by the Alaska Industrial Development and Export Authority (AIDEA), a public corporation of the State of Alaska. AIDEA issued revenue bonds in 1998 (which were refinanced in 2015) to finance its acquisition of the project. These bonds were outstanding in the amount of $45.7 million at December 31, 2022 and mature in January

2034. AELP has a PPA and operating and maintenance agreement with the AIDEA to operate and maintain the facility. This PPA is a take-or-pay obligation, expiring in December 2038, to purchase all of the output of the project. AIDEA's bonds are payable solely out of the revenues received under the PPA. Amounts payable by AELP under the PPA are equal to the required debt service on the bonds plus operating and maintenance costs. This PPA is a finance lease and, as of December 31, 2022, the finance lease obligation was $45.7 million. Snettisham Electric Company, a non-operating subsidiary of AERC, has the option to purchase the Snettisham project at any time for a price equal to the principal amount of the bonds outstanding at that time. See Note 5 of the Notes to Consolidated Financial Statements for further discussion of the Snettisham finance lease obligation. AELP also has 107.5 MW of diesel generating capacity from four facilities to provide back-up service to firm customers when necessary. The following graph shows AELP's hydroelectric generation (in thousands of MWhs) during the time periods indicated below: (1) Normal hydroelectric generation is defined as the energy output of the plant during a year with average inflows to the reservoir. As of December 31, 2022, AELP served approximately 17,600 customers. Its primary customers include city, state and federal governmental entities located in Juneau, as well as a mine located in the Juneau area. Most of AELPs customers are served on a firm basis while certain of its customers, including its largest customer, are served on an interruptible sales basis. AELP maintains separate rate tariffs for each of its customer classes, as well as seasonal rates. AVISTA CORPORATION AELPs operations are subject to regulation by the RCA with respect to rates, standard of service, facilities, accounting and certain other matters, but not with respect to the issuance of securities. Rate adjustments for AELPs customers require approval by the RCA. AELP is also subject to the jurisdiction of the FERC with respect to permits and licenses necessary to operate certain of its hydroelectric facilities. One of these licenses (for the Lake Dorothy hydroelectric project) expires in 2053 while the other (for the Salmon Creek and Annex Creek hydroelectric projects) expires in 2058. Gold Creek is not subject to a FERC license requirement. Since AELP has no electric interconnection with other utilities and makes no wholesale sales, it is not subject to general FERC jurisdiction, other than the reporting and other requirements of the Public Utility Holding Company Act of 2005 as an Avista Corp. subsidiary. The Snettisham hydroelectric project is subject to regulation by the State of Alaska with respect to dam safety and certain aspects of its operations. In addition, AELP is subject to regulation with respect to air and water quality, land use and other environmental matters under both federal and state laws. AELP ELE CTRIC OPERATING STATISTICS ##TABLE_START Years Ended December 31, ELECTRIC OPERATIONS OPERATING REVENUES (Dollars in Thousands): Residential $ 19,667 $ 18,940 $ 18,618 Commercial and government 25,782 25,861 23,754 Public street and highway lighting Total retail 45,703 45,051 42,623 Other Total electric operating revenues $ 45,704 $ 45,366 $ 42,809 ENERGY SALES (Thousands of MWhs): Residential Commercial and government Public street and highway lighting Total electric energy sales NUMBER OF RETAIL CUSTOMERS

(Average for Period): Residential 15,036 14,919 14,840 Commercial and government 2,305 2,282 2,271 Public street and highway lighting Total electric retail customers 17,577 17,431 17,339 RESIDENTIAL SERVICE AVERAGES: Annual use per customer (KWh) 10,841 10,773 10,581 Revenue per KWh (in cents) 12.07 11.84 11.86 Annual revenue per customer $ 1,307.99 $ 1,269.52 $ 1,254.58 HEATING DEGREE DAYS: (1) Juneau, AK Actual 7,923 8,394 8,119 Historical average 8,337 8,335 8,351 % of average % % % ##TABLE_END (1) Heating degree days are the measure of the coldness of weather experienced, based on the extent to which the average of high and low temperatures for a day falls below 65 degrees Fahrenheit (annual heating degree days below historical average indicate warmer than average temperatures). AVISTA CORPORATION OTHER BUS INESSES The following table shows our assets related to our other businesses, including intercompany amounts as of December 31 (dollars in thousands): ##TABLE_START Entity and Asset Type Avista Capital Unconsolidated equity investments $ 147,809 $ 91,057 Note receivable parent 1,404 Real estate investments 7,852 7,895 Notes receivable third parties 17,954 17,474 Other assets 2,865 4,294 Alaska companies (AERC and AJT Mining) 10,547 10,034 Total $ 187,027 $ 132,158 ##TABLE_END Avista Capital Unconsolidated equity investments are primarily investments in emerging technology and biotechnology companies and venture capital funds, as well as investment in a joint venture focused on local real estate development and economic growth. Real estate consists of commercial, retail office space and land. Other assets consist primarily of income tax receivables, and cash Alaska companies Includes AERC and AJT Mining, which is a wholly-owned subsidiary of AERC and is an inactive mining company holding certain real estate. AVISTA CORPORATION ITEM 1A. R ISK FACTORS RISK FACTORS The following factors could have a significant impact on our operations, results of operations, financial condition or cash flows. These factors could cause future results or outcomes to differ materially from those discussed in our reports filed with the SEC (including this Annual Report on Form 10-K), and elsewhere. Please also see Forward-Looking Statements for additional factors which could have a significant impact on our operations, results of operations, financial condition or cash flows and could cause actual results to differ materially from those anticipated in such statements. Utility Regulatory Risk Factors Regulators may not grant rates that provide timely or sufficient recovery of our costs or allow a reasonable rate of return for our shareholders. Avista Utilities' annual operating expenses and the costs associated with incremental investments in utility assets continue to grow at a faster rate than revenue. Our ability to recover these expenses and capital costs depends on the adequacy and timeliness of retail rate increases allowed by regulatory agencies, as well as managing costs. We expect to periodically file for rate increases with regulatory agencies to recover our expenses and capital costs and provide an opportunity to earn a reasonable rate of return for shareholders. If regulators do not grant rate increases or grant substantially lower rate increases than our requests in the future or if recovery of deferred expenses is disallowed, it could have a negative effect on our financial condition, results of operations or cash flows. See further discussion of regulatory matters in Item 7. Management's Discussion and Analysis Regulatory Matters. In the future, we may no longer meet the criteria for continued application of regulatory accounting principles for all or a portion of our regulated operations. If we could no longer apply regulatory accounting principles, we could be: required to write off our regulatory assets, and be precluded from the future deferral of costs or decoupled revenues not recovered through rates at the time such amounts are incurred, even if we are expected to recover these amounts from customers in the future. See further discussion at Note 1 of the Notes to Consolidated Financial Statements Regulatory Deferred Charges and Credits. Operational Risk Factors Wildfires ignited, or allegedly ignited, by Avista Corp. equipment or facilities, could cause significant loss of life and property, thereby causing serious operational and financial harm. Our equipment may be the ignition source, or alleged cause of ignition, for wildfires and in the event of a fire caused by our equipment, we could potentially be held liable for resulting damages to life and property, as well as fire suppression costs. Also, wildfires could lead to extended operational outages of our equipment while we wait for the wildfire to be extinguished before restoring power, and the cost to implement rapid response or any repair to such facilities could be significant. Any wildfires caused by our equipment could cause significant damage to our reputation, which could erode shareholder, customer and community satisfaction with our Company. In addition, wildfires caused by our equipment could lead to increased litigation and insurance costs, loss of insurance coverage, the need to be self-insured or the need to consider non-traditional insurance coverage or other risk mitigation procedures. Wildfire risks may be exacerbated by increasing temperatures and/or decreasing precipitation due to climate change experienced in the region. AVISTA CORPORATION We are subject to various operational and event risks. Our operations are subject to operational and event risks that include: severe weather or natural disasters, including, but not limited to, avalanches, wind storms, wildfires, earthquakes, snow and ice storms, and heat waves due to normal weather variations as well as the impacts of climate change which could disrupt energy generation, transmission and distribution, as well as the availability and costs of materials, equipment, supplies, support services and general business operations, blackouts or disruptions of interconnected transmission systems (the regional power grid), unplanned outages at generating plants, changes in the availability and cost of purchased power, fuel and natural gas, including delivery constraints, explosions, fires, accidents, or mechanical breakdowns that could occur while operating and maintaining our generation, transmission and distribution systems, property damage or injuries to third parties caused by our generation, transmission and distribution systems, natural disasters that can disrupt energy generation, transmission and distribution, and general business operations, terrorist attacks or other malicious acts that may disrupt or cause damage to our utility assets or the vendors we utilize, and Increased costs or delay of capital projects associated with the ability of suppliers, vendors or contractors to perform, general workforce problems, including decreased employee engagement, which may impact strategy execution and negatively affect retention, ability to attract workers, and result in challenges in collective bargaining, possible work stoppages, and strikes. Retention of employees may also be negatively impacted by early retirements, insufficient remote work opportunities, and higher pay offered by other employers. Attractions of employees to support strategies may be affected by higher pay offered from other companies, more liberal remote work opportunities offered by other employers, and other work-life balance benefits afforded by other companies. Disasters could affect the general economy, financial and capital markets, specific industries or our ability to conduct business. As protection against operational and event risks, we maintain business continuity and disaster recovery plans, maintain insurance coverage against some, but not all, potential losses and we seek to negotiate indemnification arrangements with contractors for certain event risks. However, insurance or indemnification agreements may not be adequate to protect us against liability, extra expenses and operating disruptions from all of the operational and event risks described above. In addition, we are subject to the risk that insurers and/or other parties will dispute or be unable to perform on their obligations. If insurance or indemnification agreements are unable to adequately protect us or reimburse us for out-of-pocket costs, it could have a material adverse effect on our results of operations, financial condition and cash flows. Damage to facilities could be caused by severe weather or natural disasters, such as snow, ice, wind storms, wildfires, earthquakes or avalanches. The cost to implement rapid response or any repair to such facilities can be significant. Overhead electric lines are most susceptible to damage caused by severe weather and are not covered by insurance. Physical attacks on our assets could have a negative impact on our business and our results of operations. Our generation, transmission and distribution assets and the systems that monitor and operate these assets are critical infrastructure for providing service to our customers. Security threats are continuing to evolve, and our industry has been subject to, and will likely continue to be subject to, attempts to disrupt operations. Significant destruction or interruption of these assets and systems could prevent us from fulfilling our critical business functions, including delivering energy to customers. This could result in experiencing a loss of revenues and/or additional costs to replace or restore assets and systems, and may increase costs associated with heightened security requirements. AVISTA CORPORATION Adverse impacts to AELP could result from an extended outage of its hydroelectric generating resources or its inability to deliver energy, due to its lack of interconnectivity to any other electrical grids and the cost of replacement power (diesel). AELP operates several hydroelectric power generation facilities and has diesel generating capacity from multiple facilities to provide backup service to firm customers when necessary; however, a single hydroelectric power generation facility, the Snettisham hydroelectric project, provides approximately two-thirds of AELPs hydroelectric power generation. Any issues that negatively affect AELP's ability to generate or transmit power or any decrease in the demand for the power generated by AELP could negatively affect our results of operations, financial condition and cash flows. Climate Change Risk Factors A trend of increasing average temperatures and its effects could cause significant direct and indirect impacts on our operations and results of operations . Climate change may exacerbate existing risks related to weather and weather-related events. Potential direct effects of climate change include changes in the timing and magnitude of snowpack and streamflow, impacting hydro generation; timing and magnitude of changes in electric and gas load; increased weather-related stress on, or damage to, energy infrastructure; increased frequency and intensity of extreme weather events that may impact energy generation and delivery. Indirect impacts associated with climate change may include increased costs to generate electricity or secure natural gas and deliver energy to customers; impacts to the timing or amount of operating revenues; increased costs to maintain or construct energy infrastructure in adaptation to a changing climate; increased costs or inability to obtain insurance coverage; and regional impacts to the demographic makeup, economy or financial conditions of our customers. Indirect impacts also include risks associated with new and emerging laws and regulations, which could have a material adverse impact on our business and results of operations. See further discussion at Item 7. Management's Discussion and Analysis Environmental Issues and Contingencies. Cyber and Technology Risk Factors Cyberattacks, ransomware, terrorism or other malicious acts could disrupt our businesses and have a negative impact on our results of operations and cash flows. We rely on interconnected technology systems for operation of our generating plants, electric transmission and distribution systems, natural gas distribution systems, customer billing and customer service, accounting and other administrative processes and compliance with various regulations. In addition, in the ordinary course of business, we collect and retain sensitive information including personal information about our customers and employees. Cyberattacks, ransomware, terrorism or other malicious acts could damage, destroy or disrupt these systems for an extended period of time. The energy sector, including electric and natural gas utility companies have become the subject of cyberattacks with increased frequency. Our administrative and operating networks are targeted by hackers on a regular basis. Additionally, the facilities and systems of clients, suppliers and third party service providers could be vulnerable to the same cyber or terrorism risks as our facilities and systems and such third party systems may be interconnected to our systems both physically and technologically. Therefore, an event caused by cyberattacks, ransomware or other malicious act at an interconnected third party could impact our business and facilities similarly. Any failure, unexpected, or unauthorized use of technology systems could result in the unavailability of such systems, and could result in a loss of operating revenues, an increase in operating expenses and costs to repair or replace damaged assets. Any of the above could also result in the loss or release of confidential customer and/or employee information or other proprietary data that could adversely affect our reputation and competitiveness, could result in costly litigation and negatively impact our results of operations. These cyberattacks have become more common and sophisticated and, as such, we could be required to incur costs to strengthen our systems and respond to emerging concerns. There are various risks associated with technology systems such as hardware or software failure, communications failure, data distortion or destruction, unauthorized access to data, misuse of proprietary or confidential data, unauthorized control through electronic means, programming mistakes and other deliberate or inadvertent human errors. AVISTA CORPORATION Our technology may become obsolete or we may not have sufficient resources to manage our technology. Our technology may become obsolete before the end of its useful life. In addition, custom technology that is heavily relied upon by us may not be maintained and updated appropriately due to resource restraints, or other factors, which could cause technology failures or give rise to additional operational or security risks. Technology failures could result in significant adverse effects on our operations, results of operations, financial condition and cash flows. We may be adversely affected by our inability to successfully implement certain technology projects. There are inherent risks associated with replacing and changing systems, which could have a material adverse effect on our results of operations, financial condition and cash flows. Finally, there is the risk that we ultimately do not complete a project and will incur contract cancellation or other costs, which could be significant. Strategic Risk Factors Our strategic business plans, which may be affected by any or all of the foregoing, may change, including the entry into new businesses and/or the exit from existing businesses and/or the curtailment of our business development efforts where potential future business is uncertain. Our strategic business plans could be affected by or result in any of the following: disruptive innovations in the marketplace may outpace our ability to compete or manage our risk, customers may have a choice in the future over the sources from which to receive their energy and we may not be able to compete, potential difficulties in integrating acquired operations and in realizing expected opportunities, diversions of management resources and losses of key employees, challenges with respect to operating new businesses and other unanticipated risks and liabilities, non-regulated investments in businesses outside of our core utilities operations may increase earnings volatility, market or other conditions that could adversely affect our operations or require changes to our business strategy and could result in reduced assets and net income, Affordability of electric and/or gas services may be a challenge for customers resulting in increased delayed payment for utility services, potential reputational risk arising from repeated general rate case filings, degradation in the quality of service, or from failed strategic investments and opportunities, which could erode shareholder, customer and community satisfaction with the Company, and the risk of municipalization or other form of service territory reduction. External Mandates Risk Factors External mandate risk involves forces outside the Company, which may include significant changes in customer expectations, disruptive technologies that result in obsolescence of our business model and government action that could impact the Company. Actions or limitations to address concerns over long-term climate change, both globally and within our utilities' service areas, may affect our operations and financial performance. Legislative, regulatory and advocacy efforts at the local, state, national and international levels concerning climate change and other environmental issues could have significant impacts on our operations. The electric and natural gas utility industries are frequently affected by proposals to curb greenhouse gas and other air emissions. Various regulatory and legislative proposals have been made to limit or further restrict byproducts of combustion, including that resulting from the use of natural gas by our customers. In addition, regionally, there are a number of regulatory and legislative initiatives that have been passed which are designed to limit greenhouse gas emissions and increase the use of renewable sources of energy. In addition, regulatory and AVISTA CORPORATION legislative initiatives may restrict customers' access to natural gas and/or require or limit natural gas infrastructure in buildings other initiatives may seek to promote social interests expressed as energy equity, environmental justice or similar frameworks. Any such legislation could direct and/or restrict the operation and raise the costs of our power generation resources and energy delivery infrastructure as well as the distribution of natural gas to our customers. We expect continuing legislative and regulatory activity in the future and we are evaluating the extent to which potential changes to environmental laws and regulations may: increase the operating costs of generating plants, increase the lead time and capital costs for the construction of new generating plants, require modification of our existing generating plants, require existing generating plant operations to be curtailed or shut down, reduce the amount of energy available from our generating plants, restrict the types of generating plants that can be built or contracted with, require construction of specific types of generation plants at higher cost, and increase the cost or limit our ability to distribute natural gas to customers. See Item 7. Management's Discussion and Analysis Environmental Issues and Contingencies for discussion regarding environmental issues and legislation which may affect our operations. We have contingent liabilities, including certain matters related to potential environmental liabilities, and cannot predict the outcome of these matters. In the normal course of our business, we have matters that are the subject of ongoing litigation, mediation, investigation and/or negotiation. We cannot predict the ultimate outcome or potential impact of any particular issue, including the extent, if any, of insurance coverage or that amounts payable by us may be recoverable through the ratemaking process. We are subject to environmental regulation by federal, state and local authorities related to our past, present and future operations. See Note 22 of the Notes to Consolidated Financial Statements for further details of these matters. Import tariffs could lead to increased prices on raw materials that are critical to our business. Tariffs and other restrictions on trade with foreign countries could significantly increase the prices of raw materials that are critical to our business, such as steel poles or wires. In addition, tariffs and trade restrictions could have a similar impact on our suppliers and certain customers, which could have a negative impact on our financial condition, results of operations and cash flows. See Item 7. Management's Discussion and Analysis Environmental Issues and Contingencies and Forward-Looking Statements for discussion of or reference to additional external mandates which could have a material adverse effect on our results of operations, financial condition and cash flows. Financial Risk Factors Weather (temperatures, precipitation levels, wind patterns and storms) has a significant effect on our results of operations, financial condition and cash flows. These effects could increase as climate changes occur. Weather impacts are described in the following subtopics: certain retail electricity and natural gas sales, the cost of natural gas supply, and the cost of power supply. AVISTA CORPORATION Certain retail electricity and natural gas sales volumes vary directly with changes in temperatures. We normally have our highest retail (electric and natural gas) energy sales during the winter heating season in the first and fourth quarters of the year. We also have high electricity demand for air conditioning during the summer (third quarter). In general, warmer weather in the heating season and cooler weather in the cooling season will reduce our customers energy demand and our retail operating revenues. The revenue and earnings impact of weather fluctuations is somewhat mitigated by our decoupling mechanisms; however, we could experience liquidity constraints during the period between when decoupling revenue is earned and when it is subsequently collected from customers through retail rates. The cost of natural gas supply is impacted by both supply-side factors (amount of natural gas production, level of natural gas in storage, volumes of natural gas imports and exports, regulatory restraints or costs on natural gas production and delivery) and demand-side factors (variations in winter and summer weather, level of economic growth, availability and prices of other fuels). Prices tend to increase with higher demand during periods of cold weather. Inter-regional natural gas pipelines and competition for supply can allow demand-driven price volatility in other regions of North America to affect prices in the Pacific Northwest. Increased costs adversely affect cash flows when we purchase natural gas for retail supply at prices above the amount allowed for recovery in retail rates. We defer differences between actual natural gas supply costs and the amount currently recovered in retail rates and we are generally allowed to recover substantially all of these differences after regulatory review. However, these deferred costs require cash outflows from the time of natural gas purchases until the costs are later recovered through retail sales. The cost of power supply can be significantly affected by weather, and therefore is subject to trends in climate change. Precipitation (consisting of snowpack, its water content and runoff pattern plus rainfall) and other streamflow conditions (such as regional water storage operations) significantly affect hydroelectric generation capability. Variations in hydroelectric generation inversely affect our reliance on market purchases and thermal generation. To the extent that hydroelectric generation is less than normal, significantly more costly power supply resources must be acquired and the ability to realize net benefits from surplus hydroelectric wholesale sales is reduced. Wholesale prices also vary based on wind patterns as wind generation capacity is material in the Pacific Northwest but its contribution to supply is inconsistent. The price of power in the wholesale energy markets tends to be higher during periods of high regional demand, such as occurs with temperature extremes. Climate change may increase the frequency and magnitude of temperature extremes. We may need to purchase power in the wholesale market during peak price periods. The price of natural gas as fuel for natural gas-fired electric generation also tends to increase during periods of high demand which are often related to temperature extremes. We may need to purchase natural gas fuel in these periods of high prices to meet electric demands. The cost of power supply during peak usage periods may be higher than the retail sales price or the amount allowed in retail rates by our regulators. To the extent that power supply costs are above the amount allowed currently in retail rates, the difference is partially absorbed by the Company in current expense and is partially deferred or shared with customers through regulatory mechanisms. However, these deferred costs require cash outflows from the time of power purchases until the costs are later recovered through retail sales. The price of power tends to be lower during periods with excess supply, such as the spring when hydroelectric conditions are usually at their maximum and various facilities are required to operate to meet environmental mandates. Oversupply can be exacerbated when intermittent resources such as wind generation are producing output that may be supported by price subsidies. In extreme situations, we may be required to sell excess energy at negative prices. As a result of these combined factors, our net cost of power supply the difference between our costs of generation and market purchases, reduced by our revenue from wholesale sales varies significantly because of weather. We rely on regular access to financial markets but we cannot assure favorable or reasonable financing terms will be available when we need them. Access to capital markets is critical to our operations and our capital structure. We have significant capital requirements that we expect to fund, in part, by accessing capital markets. As such, the state of financial markets and credit availability in the global, United States and regional economies impacts our financial condition. We could experience increased borrowing costs or limited access to capital on reasonable terms. AVISTA CORPORATION We access long-term capital markets to finance capital expenditures, repay maturing long-term debt and obtain additional working capital, including needs related to power and natural gas purchases and sales, from time-to-time. Our ability to access capital on reasonable terms is subject to numerous factors and market conditions, many of which are beyond our control. If we are unable to obtain capital on reasonable terms, it may limit or prohibit our ability to finance capital expenditures and repay maturing long-term debt. Our liquidity needs could exceed our short-term credit availability and lead to defaults on various financing arrangements. We would also likely be prohibited from paying dividends on our common stock. Performance of the financial markets could also result in significant declines in the market values of assets held by our pension plan and/or a significant increase in the pension liability (which impacts the funded status of the plan) and could increase future funding obligations and pension expense. We rely on credit from financial institutions for short-term borrowings. We need adequate levels of credit with financial institutions for short-term liquidity. There is no assurance that we will have access to credit beyond the expiration dates of our committed line of credit agreements. These agreements contain customary covenants and default provisions. Any default on the lines of credit or other financing arrangements of Avista Corp. or any of our significant subsidiaries, if any, could result in cross-defaults to other agreements of such entity, and/or to the line of credit or other financing arrangements of any other of such entities. Any defaults could also induce vendors and other counterparties to demand collateral. In the event of any such default, it would be difficult for us to obtain financing on reasonable terms to pay creditors or fund operations. We would also likely be prohibited from paying dividends on our common stock. We hedge a portion of our interest rate risk with financial derivative instruments that may require us to post collateral. If market interest rates decrease below the interest rates we have locked in, this will result in a liability related to our interest rate swap derivatives, which can be significant. We may be required to post cash or letters of credit as collateral depending on fluctuations in the fair value of the derivative instruments. Settlement of interest rate swap derivative instruments in a liability position could require a significant amount of cash, which could negatively impact our liquidity and short-term credit availability and increase interest expense over the term of the associated debt. Downgrades in our credit ratings could impede our ability to obtain financing, adversely affect the terms of financing and impact our ability to transact for or hedge energy resources. If we do not maintain our investment grade credit rating with the major credit rating agencies, we could expect increased debt service costs, limitations on our ability to access capital markets or obtain other financing on reasonable terms, and requirements to provide collateral (in the form of cash or letters of credit) to lenders and counterparties. In addition, credit rating downgrades could reduce the number of counterparties willing to do business with us or result in the termination of outstanding regulatory authorizations for certain financing activities. Credit risk may be affected by industry concentration and geographic concentration. We have concentrations of suppliers and customers in the electric and natural gas industries including: electric and natural gas utilities, electric generators and transmission providers, oil and natural gas producers and pipelines, financial institutions including commodity clearing exchanges and related parties, and energy marketing and trading companies. We have concentrations of credit risk related to our geographic location in the western United States and western Canada energy markets. These concentrations of counterparties and concentrations of geographic location may affect our overall exposure to credit risk because the counterparties may be similarly affected by changes in conditions. AVISTA CORPORATION Energy Commodity Risk Factors Energy commodity price changes affect our cash flows and results of operations. Energy commodity prices can be volatile. We rely on energy markets and other counterparties for energy supply, surplus and optimization transactions and commodity price hedging. A combination of factors exposes our operations to commodity price risks, including: our obligation to serve our retail customers at rates set through the regulatory process - we cannot decline to serve our customers and we cannot change retail rates to reflect current energy prices unless and until we receive regulatory approval, customer demand, which is beyond our control because of weather, customer choices, prevailing economic conditions and other factors, some of our energy supply cost is fixed by the nature of the energy-producing assets or through contractual arrangements (however, a significant portion of our energy resource costs are not fixed), and the potential non-performance by commodity counterparties, which could lead to replacement of the scheduled energy or natural gas at higher prices. Because we must supply the amount of energy demanded by our customers and we must sell it at fixed rates and only a portion of our energy supply costs are fixed, we are subject to the risk of buying energy at higher prices in wholesale energy markets (and the risk of selling energy at lower prices if we are in a surplus position). Electricity and natural gas in wholesale markets are commodities with historically high price volatility. Changes in wholesale energy prices affect, among other things, the cash requirements to purchase electricity and natural gas for retail customers or wholesale obligations and the market value of derivative assets and liabilities. We hedge a portion of our energy commodity risk with physical and financial derivative instruments that may require us to post collateral. When we enter into fixed price energy commodity transactions for future delivery, we are subject to credit terms that may require us to provide collateral to wholesale counterparties related to the difference between current prices and the agreed upon fixed prices. These collateral requirements can place significant demands on our cash flows or borrowing arrangements. Price volatility can cause collateral requirements to change quickly and significantly. Cash flow deferrals related to energy commodities can be significant. We are permitted to collect from customers only amounts approved by regulatory commissions. However, our costs to provide energy service can be much higher or lower than the amounts currently billed to customers. We are permitted to defer income statement recognition and recovery from customers for some of these differences, which are recorded as deferred charges with the opportunity for future recovery through retail rates. These deferred costs are subject to review for prudence and potential disallowance by regulators, who have discretion as to the extent and timing of future recovery or refund to customers. Power and natural gas costs higher than those recovered in retail rates negatively impact cash flows. Amounts that are not allowed for deferral or which are not approved to become part of customer rates affect our results of operations. Even if our regulators ultimately allow us to recover deferred power and natural gas costs, our operating cash flows can be negatively affected until these costs are recovered from customers. Fluctuating energy commodity prices and volumes in relation to our energy risk management process can cause volatility in our cash flows and results of operations. We engage in active hedging and resource optimization practices to reduce energy cost volatility and economic exposure related to commodity price fluctuations. We routinely enter into contracts to hedge a portion of our purchase and sale commitments for electricity and natural gas, as well as forecasted excess or deficit energy positions and inventories of natural gas. We use physical energy contracts and derivative instruments, such as forwards, futures, swaps and options traded in the over-the-counter markets or on exchanges. If market prices decrease compared to the prices we have locked in with our energy commodity derivatives, this will result in a liability related to these derivatives, which AVISTA CORPORATION can be significant. As a result of price fluctuations, we may be required to post significant amounts of cash or letters of credit as collateral depending on fluctuations in the fair value of the derivative instruments. We do not attempt to fully hedge our energy resource assets or our forecasted net positions for various time horizons. To the extent we have positions that are not hedged, or if hedging positions do not fully match the corresponding purchase or sale, fluctuating commodity prices could have a material effect on our operating revenues, resource costs, derivative assets and liabilities, and operating cash flows. In addition, actual loads and resources typically vary from forecasts, sometimes to a significant degree, which require additional transactions or dispatch decisions that impact cash flows. The hedges we enter into are reviewed for prudence by our various regulators and any deferred costs (including those as a result of our hedging transactions) are subject to review for prudence and potential disallowance by regulators. Generation plants may become obsolete. We rely on a variety of generation and energy commodity market sources to fulfill our obligation to serve customers and meet the demands of our counterparty agreements. Some of our generation sources, such as coal, may become obsolete or be prematurely retired through regulatory action or legislation. This could result in higher commodity costs to replace the lost generation, as well as higher costs to retire the generation source before the end of its expected life. This also includes costs (including replacement of lost generation) associated with our transfer of Colstrip ownership to NorthWestern at the end of 2025. See Item 7. Management's Discussion and Analysis Environmental Issues and Contingencies for discussion regarding environmental and other issues surrounding Colstrip. Compliance Risk Factors There have been numerous changes in legislation, related administrative rulemakings, and Executive Orders, including periodic audits of compliance with such rules, which may adversely affect our operational and financial performance. We expect to continue to be affected by legislation at the national, state and local level, as well as by administrative rules and requirements published by government agencies, including but not limited to the FERC, the EPA and state regulators. We are also subject to NERC and WECC reliability standards. The FERC, the NERC and the WECC perform periodic audits of the Company. Failure to comply with the FERC, the NERC, or the WECC requirements can result in financial penalties. Future legislation, administrative rules or Executive Orders could have a material adverse effect on our operations, results of operations, financial condition and cash flows.

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ITEM 1. BUSINESS History and Organization Black Hills Corporation, a South Dakota corporation (together with its subsidiaries, referred to herein as the Company, we, us or our), is a customer-focused, growth-oriented utility company headquartered in Rapid City, South Dakota (incorporated in South Dakota in 1941). We operate our business in the United States, reporting our operating results through our Electric Utilities and Gas Utilities segments. Certain unallocated corporate expenses that support our operating segments are presented as Corporate and Other. Our Electric Utilities segment generates, transmits and distributes electricity to approximately 220,000 electric utility customers in Colorado, Montana, South Dakota and Wyoming. We also own and operate non-regulated power generation and mining assets that are vertically integrated into and primarily contracted to our Electric Utilities. Our Electric Utilities own 1,482 MW of generation and 9,024 miles of electric transmission and distribution lines. Our Gas Utilities segment serves approximately 1,107,000 natural gas utility customers in Arkansas, Colorado, Iowa, Kansas, Nebraska, and Wyoming. Our Gas Utilities own and operate 4,713 miles of intrastate gas transmission pipelines and 42,222 miles of gas distribution mains and service lines, seven natural gas storage sites, more than 50,000 horsepower of compression and over 515 miles of gathering lines. Electric Utilities We conduct electric utility operations through our Colorado, South Dakota and Wyoming subsidiaries. Our electric generating facilities and power purchase agreements provide for the supply of electricity principally to our retail customers. Additionally, we sell excess power to other utilities and marketing companies, including our affiliates. We also provide non-regulated services to our retail customers under the Service Guard Comfort Plan and Tech Services. Additionally, we own and operate non-regulated power generation and mining assets that are vertically integrated into and primarily support our Electric Utilities. Nearly all of these operations are located at our electric generating complexes and are physically integrated into our Electric Utilities operations. ##TABLE_START As of December 31, Retail Customers Residential 188,921 186,852 184,872 Commercial 30,404 30,326 30,225 Industrial Other 1,024 1,010 1,017 Total Electric Retail Customers at End of Year 220,431 218,269 216,197 ##TABLE_END ##TABLE_START As of December 31, Retail Customers Colorado Electric 100,573 99,709 98,735 South Dakota Electric 75,169 74,509 73,700 Wyoming Electric 44,689 44,051 43,762 Total Electric Retail Customers at End of Year 220,431 218,269 216,197 ##TABLE_END Capacity and Demand. System Peak Demand for the Electric Utilities retail customers for each of the last three years are listed below: ##TABLE_START System Peak Demand (in MW) 2022 (a) Summer Winter Summer Winter Summer Winter Colorado Electric South Dakota Electric Wyoming Electric ##TABLE_END ____________________ (a) In December 2022, each of our Electric Utilities set new winter peak loads. In July 2022, South Dakota Electric and Wyoming Electric set new all-time and summer peak loads. See recent peak discussion in the Recent Developments section of Managements Discussion and Analysis of Financial Condition and Results of Operations in Item 7 in this Annual Report on Form 10-K for additional information. As of December 31, 2022, our Electric Utilities ownership interests in electric generating plants were as follows: ##TABLE_START Unit Fuel Type Location Ownership Interest % (d) Owned Nameplate Capacity (MW) In Service Date Colorado Electric: Busch Ranch I (a) Wind Pueblo, Colorado 50% 14.5 Peak View (b) (c) Wind Pueblo, Colorado 100% 60.8 Pueblo Airport Generation #1-2 Gas Pueblo, Colorado 100% 200.0 Pueblo Airport Generation CT #6 Gas Pueblo, Colorado 100% 40.0 AIP Diesel Oil Pueblo, Colorado 100% 10.0 Diesel #1 and #3-5 Oil Pueblo, Colorado 100% 8.0 Diesel #1-5 Oil Rocky Ford, Colorado 100% 10.0 South Dakota Electric: Cheyenne Prairie Gas Cheyenne, Wyoming 58% 58.0 Corriedale (c) Wind Cheyenne, Wyoming 62% 32.5 Wygen III Coal Gillette, Wyoming 52% 60.3 Neil Simpson II Coal Gillette, Wyoming 100% 90.0 Wyodak Plant Coal Gillette, Wyoming 20% 80.5 Neil Simpson CT Gas Gillette, Wyoming 100% 40.0 Lange CT Gas Rapid City, South Dakota 100% 40.0 Ben French Diesel #1-5 Oil Rapid City, South Dakota 100% 10.0 Ben French CTs #1-4 Gas/Oil Rapid City, South Dakota 100% 100.0 1977-1979 Wyoming Electric: Cheyenne Prairie Gas Cheyenne, Wyoming 42% 42.0 Cheyenne Prairie CT Gas Cheyenne, Wyoming 100% 40.0 Corriedale (c) Wind Cheyenne, Wyoming 38% 20.0 Wygen II Coal Gillette, Wyoming 100% 95.0 Integrated Generation: Wygen I Coal Gillette, Wyoming 76.5% 68.9 Pueblo Airport Generation #4-5 Gas

Pueblo, Colorado 50.1% (e) 200.0 Busch Ranch I (a) Wind Pueblo, Colorado 50% 14.5 Busch Ranch II (c) Wind Pueblo, Colorado 100% 59.4 Northern Iowa Windpower (c) Wind Joice, Iowa 100% 87.1 Total MW Capacity 1,481.5 ##TABLE_END ____________________ (a) In 2013, Busch Ranch I was awarded a one-time cash grant in lieu of ITCs under the Section 1603 program created under the American Recovery and Reinvestment Act. (b) The PTCs for Peak View flow back to customers through a rider mechanism as a reduction to Colorado Electrics margins. (c) This facility qualifies for PTCs at $26/MWh under IRC 45 during the 10-year period beginning on the date the facility was originally placed in service. (d) Jointly owned facilities are discussed in Note 6 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K. (e) In 2016, Black Hills Electric Generation sold a 49.9% non-controlling interest in Black Hills Colorado IPP to a third party. See Note 12 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for additional information. Our Electric Utilities power supply by resource as a percent of the total power supply for our energy needs for the years ended December 31 was as follows: ##TABLE_START Power Supply Coal 35.1 % 34.2 % 40.3 % Natural Gas and Diesel Oil (a) 18.8 % 24.4 % 25.0 % Wind 11.4 % 11.3 % 8.8 % Total Generated 65.3 % 69.9 % 74.1 % Coal, Natural Gas, Oil and Other Market Purchases 29.6 % 25.1 % 21.1 % Wind Purchases 5.1 % 5.0 % 4.8 % Total Purchased 34.7 % 30.1 % 25.9 % Total 100.0 % 100.0 % 100.0 % ##TABLE_END ____________________ (a) The diesel-fueled generating units are generally used as supplemental peaking units. Power generated from these units, as a percentage of total power supply, was 0.0% for each of the years presented. Our Electric Utilities weighted average cost of fuel utilized to generate electricity and the average price paid for purchased power (excluding contracted capacity) per MWh for the years ended December 31 were as follows: ##TABLE_START Fuel and Purchased Power (dollars per MWh) Coal $ 12.76 $ 11.55 $ 11.38 Natural Gas and Diesel Oil 37.09 33.65 8.59 Total Generated Weighted Average Fuel Cost 17.57 17.40 9.09 Coal, Natural Gas, Oil and Other Market Purchases 66.35 64.85 40.80 Wind Purchases 33.78 34.69 42.06 Total Purchased Power Weighted Average Cost 61.56 59.84 41.03 Total Weighted Average Fuel and Purchased Power Cost $ 32.82 $ 30.17 $ 17.36 ##TABLE_END Purchased Power. We have executed various PPAs to support our Electric Utilities capacity and energy needs beyond our regulated power plants generation, which include long-term related party agreements with our non-regulated power generation businesses. See additional information in Note 3 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K. Coal Mining. We own and operate a single coal mine through our WRDC subsidiary which is reported within our Electric Utilities segment. We surface mine, process and sell low-sulfur sub-bituminous coal at our mine located immediately adjacent to our Gillette energy complex in the Powder River Basin in northeastern Wyoming, where our five coal-fired power plants are located. We produced approximately 3.7 million tons of coal in 2022. The mine provides low-sulfur coal directly to these five power plants via a conveyor belt system, minimizing transportation costs.

The fuel can be delivered to our adjacent power plants at very cost competitive prices (i.e., $1.09 per MMBtu for year ended December 31, 2022) when compared to alternatives. Nearly all of the mines production is sold to our on-site generation facilities under long-term supply contracts. As of December 31, 2022, we estimated our recoverable reserves to be approximately 174 million tons, based on a life-of-mine engineering study utilizing currently available drilling data and geological information prepared by internal engineering analyses. The recoverable reserve life is equal to approximately 47 years at the current production levels. Transmission and Distribution. Through our Electric Utilities, we own electric transmission and distribution systems composed of high voltage lines (greater than 69 kV) and low voltage lines (69 kV or less). We also jointly operate an electric transmission system, referred to as the Common Use System, with Basin Electric Power Cooperative and Powder River Energy Corporation. Each participant in the Common Use System individually owns assets that are operated together for a single system. The Common Use System also provides transmission service to our Transmission Tie. South Dakota Electric owns 35% of the Transmission Tie. The Transmission Tie is further discussed in Note 6 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K. At December 31, 2022, our Electric Utilities owned the electric transmission and distribution lines shown below: ##TABLE_START Utility State Transmission (a) (in Line Miles) Distribution (in Line Miles) Colorado Electric Colorado 3,198 South Dakota Electric (b) South Dakota, Wyoming 1,235 2,587 Wyoming Electric Wyoming 1,347 1,892 7,132 ##TABLE_END ____________________ (a) Electric transmission line miles include voltages of 69 kV and above. (b) South Dakota Electric transmission line miles include 43 miles within the Common Use System. Material transmission services agreements are disclosed in Note 3 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K. Seasonal Variations of Business. Our Electric Utilities are seasonal businesses and weather patterns may impact their operating performance. Demand for electricity is sensitive to seasonal cooling, heating and industrial load requirements, as well as market price. In particular, cooling demand is often greater in the summer and heating demand is often greater in the winter. Competition. We generally have limited competition for the retail generation and distribution of electricity in our service areas. Various legislative or regulatory restructuring and competitive initiatives have been discussed in several of the states in which our utilities operate. These initiatives would be aimed at increasing competition or providing for distributed generation. To date, these initiatives have not had a material impact on our utilities. In Colorado, our electric utility is subject to rules which may require competitive bidding for generation supply. Because of these rules, we face competition from other utilities and non-affiliated IPPs for the right to supply electric energy and capacity for Colorado Electric when resource plans require additional resources. Additionally, electrification initiatives in our service territories could increase demand for electricity and increase customer growth. The independent power industry consists of many strong and capable competitors, some of which may have more extensive operations or greater financial resources than we possess. With respect to the merchant power sector, FERC has taken steps to increase access to the national transmission grid by utility and non-utility purchasers and sellers of electricity to foster competition within the wholesale electricity markets. Our non-regulated power generation businesses could face greater competition if utilities are permitted to robustly invest in power generation assets. Conversely, state regulations requiring utilities to competitively bid generation resources may provide opportunity for IPPs in some regions. To date, these initiatives have not had a material impact on our non-regulated power generation businesses. Our mining business strategy is to sell nearly all of our production to on-site generation facilities under long-term supply contracts. Historically, any off-site sales have been to consumers within close proximity to the WRDC mine. Rail transport market opportunities for WRDC are limited due to the lower heating value (Btu) of the coal, combined with the fact that the WRDC mine is served by only one railroad, resulting in less competitive transportation rates. Additionally, coal competes with other energy sources, such as natural gas, wind, solar and hydropower. Costs and other factors relating to these alternative fuels, such as safety, environmental and availability considerations affect the overall demand for coal as a fuel. Operating Statistics . See a summary of key operating statistics in the Electric Utilities segment operating results within Managements Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Annual Report on Form 10-K. Gas Utilities We conduct natural gas utility operations through our Arkansas, Colorado, Iowa, Kansas, Nebraska and Wyoming subsidiaries. Our Gas Utilities transport and distribute natural gas through our distribution network to approximately 1,107,000 customers. Additionally, we sell contractual pipeline capacity and gas commodities to other utilities and marketing companies, including our affiliates, on an as-available basis. We also provide non-regulated services to our regulated customers. Black Hills Energy Services provides natural gas supply to approximately 52,600 retail distribution customers under the Choice Gas Program in Nebraska and Wyoming. Additionally, we provide services under the Service Guard Comfort Plan, Tech Services and HomeServe. ##TABLE_START As of December 31, Retail Customers Residential 864,038 853,908 844,999 Commercial 85,203 84,234 83,135 Industrial 2,189 2,158 2,235 Transportation 155,685 153,929 152,568 Total Natural Gas Retail Customers at End of Year 1,107,115 1,094,229 1,082,937 ##TABLE_END ##TABLE_START As of December 31, Retail Customers Arkansas Gas 183,270 180,216 178,281 Colorado Gas 208,060 202,747 197,817 Iowa Gas 162,801 161,905 160,952 Kansas Gas 118,599 117,862 116,973 Nebraska Gas 301,007 298,832 296,778 Wyoming Gas 133,378 132,667 132,136 Total Natural Gas Retail Customers at End of Year 1,107,115 1,094,229 1,082,937 ##TABLE_END We procure natural gas for our distribution customers from a diverse mix of producers, processors and marketers and generally use hedging, physical fixed-price purchases and market-based price purchases to achieve dollar-cost averaging within our natural gas portfolio. The majority of our procured natural gas is transported in interstate pipelines under firm transportation service agreements. In addition to company-owned natural gas storage assets in Arkansas, Colorado and Wyoming, we also contract with third-party transportation providers for natural gas storage service to provide gas supply during the winter heating season and to meet peak day customer demand for natural gas. The following table summarizes certain information regarding our company-owned regulated underground gas storage facilities as of December 31, 2022: ##TABLE_START Working Capacity (Mcf) Cushion Gas (Mcf) Total Capacity (Mcf) Maximum Daily Withdrawal Capability (Mcfd) Arkansas Gas 9,273,700 13,433,040 22,706,740 196,000 Colorado Gas 2,361,495 6,164,715 8,526,210 30,000 Wyoming Gas 5,733,900 17,545,600 23,279,500 36,000 Total 17,369,095 37,143,355 54,512,450 262,000 ##TABLE_END The following table summarizes certain information regarding our system infrastructure as of December 31, 2022: ##TABLE_START Intrastate Gas Transmission Pipelines (in line miles) Gas Distribution Mains (in line miles) Gas Distribution Service Lines (in line miles) Arkansas Gas 5,070 1,330 Colorado Gas 7,088 2,372 Iowa Gas 2,879 2,503 Kansas Gas 3,004 1,388 Nebraska Gas 1,317 8,558 2,796 Wyoming Gas 1,316 3,563 1,671 Total 4,713 30,162 12,060 ##TABLE_END Seasonal Variations of Business. Our Gas Utilities are seasonal businesses and weather patterns may impact their operating performance. Demand for natural gas is sensitive to seasonal heating and industrial load requirements, as well as market price. In particular, demand is often greater in the winter months for heating. Natural gas is used primarily for residential and commercial heating, and demand for this product can depend heavily upon weather throughout our service territories. As a result, a significant amount of natural gas revenue is normally recognized in the heating season consisting of the first and fourth quarters. Demand for natural gas can also be impacted by summer temperatures and precipitation, which can affect demand for irrigation. Competition. We generally have limited competition for the retail distribution of natural gas in our service areas. Various restructuring and competitive initiatives have been discussed in several of the states in which our utilities operate. These initiatives are aimed at increasing competition. Additionally, electrification initiatives in our service territories could negatively impact demand for natural gas and decrease growth. To date, these initiatives have not had a material impact on our utilities. Although we face competition from independent marketers for the sale of natural gas to our industrial and commercial customers, in instances where independent marketers displace us as the seller of natural gas, we still collect fees for transporting the gas through our distribution network. Operating statistics . See a summary of key operating statistics in the Gas Utilities segment operating results within Managements Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Annual Report on Form 10-K. Utility Regulation Characteristics Our Utilities are subject to regulation by a number of federal, state and other organizations, including, but not limited to, the following: State public utility commissions, which have jurisdiction over services and facilities, rates and charges, accounting, valuation of property, depreciation rates and various other matters; the FERC, which oversees the acquisition and disposition of generation, transmission and other facilities, transmission of electricity and natural gas in interstate commerce, proposals to build and operate interstate natural gas pipelines and storage facilities, and wholesale purchases and sales of electric energy, among other things; the NERC, which, through its regional entities, establishes and enforces mandatory reliability standards, subject to approval by the FERC, to ensure the reliability of the U.S. electric transmission and generation system and to prevent major system blackouts; the EPA, which has the responsibility to maintain and enforce national standards under a variety of environmental laws, in some cases delegating authority to state agencies. The EPA also works with industries and all levels of government, including federal and state governments, in a wide variety of voluntary pollution prevention programs and energy conservation efforts; the TSA, which regulates certain activities related to the safety and security of natural gas pipelines. In May and July 2021 the TSA issued security directives that included several new cybersecurity requirements for critical pipeline owners and operators; and the PHMSA, which is responsible for administering the federal regulatory program to help ensure the safe transportation of natural gas, petroleum and other hazardous materials by pipelines, including pipelines associated with natural gas storage, and develops regulations and other approaches to risk management to help ensure safety in design, construction, testing, operation, maintenance and emergency response of pipeline facilities. Rates and Regulation Our Utilities are subject to the jurisdiction of the public utility commissions in the states where they operate and the FERC for certain assets and transactions. These commissions oversee services and facilities, rates and charges, accounting, valuation of property, depreciation rates and various other matters. Rate decisions are influenced by many factors, including the cost of providing service, capital expenditures, the prudence of costs we incur, views concerning appropriate rates of return, general economic conditions and the political environment. Certain commissions also have jurisdiction over the issuance of debt or securities and the creation of liens on property located in their states to secure bonds or other securities. The regulatory provisions for recovering the costs of service vary by jurisdiction. Our Utilities have cost recovery mechanisms that allow us to pass the prudently-incurred cost of natural gas, fuel and purchased power to customers. These mechanisms allow the utility operating in that state to collect or refund the difference between the cost of commodities and certain services embedded in our base rates and the actual cost of the commodities and certain services without filing a general rate review. In addition, some jurisdictions allow us to recover certain costs or earn a return on capital investments placed in service between base rate reviews through approved rider tariffs, such as energy efficiency plan costs and system safety and integrity investments. These tariffs allow the utility a return on the investment. Electric Utilities The following table provides regulatory information for each of our Electric Utilities: ##TABLE_START Subsidiary Jurisdiction Authorized Rate of Return on Equity Authorized Return on Rate Base Authorized Capital Structure Debt/Equity Authorized Rate Base (in millions) Effective Date Additional Regulatory Mechanisms Percentage of Power Marketing Profit Shared with Customers Colorado

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Electric (a) CO 9.37% 7.43% 48%/52% $539.6 1/2017 ECA, TCA, PCCA, EECR/DSM, RESA 90% CO 9.37% 6.02% 67%/33% $57.9 1/2017 CACJA Adjustment Rider N/A South Dakota Electric WY 9.90% 8.13% 47%/53% $46.8 10/2014 ECA 65% SD Global Settlement 7.76% Global Settlement $543.9 10/2014 ECA, TFA, EIA 70% FERC 10.80% 8.76% 43%/57% $177.8 (b) 2/2009 FERC Transmission Tariff N/A Wyoming Electric (a) (c) WY 9.75% 7.48% 48%/52% $506.4 3/2023 PCA, EECR/DSM, Rate Base Recovery on Acquisition Adjustment, TCAM N/A ##TABLE_END ____________________ (a) For both Colorado Electric and Wyoming Electric, transmission investments are recovered through retail rates rather than FERC Transmission Tariffs. Effective September 1, 2022, a formulaic approach determines the revenue component of Colorado Electric's open access transmission tariff. (b) Includes $160.7 million in 2022 rate base for the 2022 Projected Common Use System formula rate that is updated annually and $17.1 million in rate base for the Transmission Tie that is based on the approved stated rate from 2005. (c) For additional information regarding recent rate review updates, see Note 2 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K. The following table summarizes the mechanisms we have in place for each of our Electric Utilities: ##TABLE_START Cost Recovery Mechanisms Electric Utility Jurisdiction Environmental Cost EECR/DSM Transmission Expense Fuel Cost Transmission Capital Purchased Power RESA Colorado Electric South Dakota Electric (SD) (a) South Dakota Electric (WY) (b) South Dakota Electric (FERC) (c) Wyoming Electric (d) ##TABLE_END ____________________ (a) South Dakota Electrics EIA and TFA tariffs were suspended for a six-year moratorium period effective July 1, 2017. On January 7, 2020, South Dakota Electric received approval from the SDPUC to extend the 6-year moratorium period by an additional 3 years whereby these recovery mechanisms will not be effective prior to July 1, 2026. (b) South Dakota Electric has WPSC authorization to accumulate certain Energy Efficiency costs in a regulatory asset with determination of recovery to be made in the next rate review. (c) South Dakota Electric has an approved FERC Transmission Tariff based on a formulaic approach that determines the revenue component of South Dakota Electrics open access transmission tariff. (d) Wyoming Electric has a WPSC-approved transmission tariff based on a formulaic approach that determines the recovery of Wyoming Electric's transmission costs. Gas Utilities The following table provides regulatory information for each of our Gas Utilities: ##TABLE_START Subsidiary Jurisdiction Authorized Rate of Return on Equity Authorized Return on Rate Base Authorized Capital Structure Debt/Equity Authorized Rate Base (in millions) Effective Date Additional Regulatory Mechanisms Arkansas Gas (a) AR 9.60% 6.20% (b) 55%/45% $674.6 (c) 10/2022 GCA, Safety and Integrity Rider, EECR, Weather Normalization Adjustment, Billing Determinant Adjustment Colorado Gas (a) CO 9.20% 6.56% 50%/50% $303.20 1/2022 GCA, SSIR, EECR/DSM RMNG CO 9.90% 6.71% 53%/47% $118.70 6/2018 SSIR, Liquids/Off-system/Market Center Services Revenue Sharing Iowa Gas (a) IA 9.60% 6.75% 50%/50% $300.90 1/2022 GCA, EECR, System Safety and Maintenance Adjustment Rider, Gas Supply

Ticker: BKH, Sector: Utilities, Filed At: 2023-02-14T14:29:14-05:00

Optimization revenue sharing Kansas Gas (a) KS Global Settlement Global Settlement Global Settlement Global Settlement 1/2022 GCA, Weather Normalization Tariff, Gas System Reliability Surcharge, Ad Valorem Tax Surcharge, Cost of Bad Debt Collected through GCA, Pension Levelized Adjustment, Tax Adjustment Rider, Gas Supply Optimization revenue sharing Nebraska Gas (d) NE 9.50% 6.71% 50%/50% $504.20 3/2021 GCA, Cost of Bad Debt Collected through GCA, Infrastructure System Replacement Cost Recovery Surcharge, Choice Gas Program, SSIR, Bad Debt expense recovered through Choice Supplier Fee, Line Locate Surcharge, HEAT Program Wyoming Gas (d) WY 9.40% 6.98% 50%/50% $354.40 3/2020 GCA, EECR, Rate Base Recovery on Acquisition Adjustment, Wyoming Integrity Rider, Choice Gas Program ##TABLE_END ____________________ (a) For additional information regarding recent rate review updates, see Note 2 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K. (b) Arkansas Gas return on rate base is adjusted to remove certain liabilities from rate review capital structure for comparison with other subsidiaries. (c) Arkansas Gas rate base is adjusted to include certain liabilities for comparison with other subsidiaries. (d) The Choice Gas Program mechanisms are applicable to only a portion of Nebraska Gas and Wyoming Gas customers. The following table summarizes the mechanisms we have in place for each of our Gas Utilities: ##TABLE_START Gas Utility Jurisdiction Cost Recovery Mechanisms EECR/DSM Integrity Additions Bad Debt Weather Normal Pension Recovery Gas Cost (b) Revenue Decoupling Arkansas Gas Colorado Gas RMNG (a) Iowa Gas Kansas Gas Nebraska Gas Wyoming Gas ##TABLE_END ____________________ (a) RMNG, which is an intrastate transmission pipeline that provides natural gas transmission and wholesale services in western Colorado, has an SSIR mechanism which allows recovery of investments through December 31, 2021. The other cost recovery mechanisms are not applicable to RMNG. (b) All of our Gas Utilities, except where the Choice Gas Program is the only option, have GCAs that allow us to pass the prudently-incurred cost of gas and certain services through to the customer between rate reviews. Recent Tariff Filings See Note 2 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K for information regarding current regulatory activity. FERC The Federal Power Act gives FERC exclusive rate-making jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Pursuant to the Federal Power Act, all public utilities subject to FERCs jurisdiction must maintain tariffs and rate schedules on file with FERC that govern the rates, and terms and conditions for the provision of FERC-jurisdictional wholesale power and transmission services. Public utilities are also subject to accounting, record-keeping and reporting requirements administered by FERC. FERC also places certain limitations on transactions between public utilities and their affiliates. Our public Electric Utility subsidiaries provide FERC-jurisdictional services subject to FERCs oversight. Our Electric Utilities entities are authorized by FERC to make wholesale sales of electric capacity and energy at market-based rates under tariffs on file with FERC. As a condition of their market-based rate authority, Electric Quarterly Reports are filed with FERC. Our Electric Utilities own and operate FERC-jurisdictional interstate transmission facilities and provide open access transmission service under tariffs on file with FERC. Our Electric Utilities are subject to routine audit by FERC with respect to their compliance with FERCs regulations. PUHCA 2005 provides FERC authority with respect to the books and records of a utility holding company. As a utility holding company whose assets consist primarily of investments in our subsidiaries, including subsidiaries that are public utilities and also a centralized service company subsidiary, BHSC, we are subject to FERCs authority under PUHCA 2005. PUHCA 2005 reiterated the definition and benefits of EWG status. Under PUHCA 2005, an EWG is an entity or generator engaged, directly or indirectly through one or more affiliates, exclusively in the business of owning, operating or both owning and operating all or part of one or more eligible facilities and selling electric energy at wholesale. Though EWGs are public utilities within the definition set forth in the Federal Power Act and are subject to FERC regulation of rates and charges, they are exempt from other FERC requirements. Through its subsidiaries, Black Hills Corporation is affiliated with three EWGs, Wygen I, Pueblo Airport Generation (facilities #4-5) and Northern Iowa Windpower. Each of these three EWGs have been granted market-based rate authority. NERC The Energy Policy Act of 2005 included provisions to create an Electric Reliability Organization, which is required to promulgate mandatory reliability standards governing the operation of the bulk power system in the U.S. FERC certified NERC as the Electric Reliability Organization and also issued an initial order approving many reliability standards that went into effect in 2007. Entities that violate standards can be subject to fines and can also be assessed non-monetary penalties, depending upon the nature and severity of the violation. Pipeline Security In May and July 2021, the TSA issued security directives in response to a ransomware attack on the Colonial Pipeline that occurred earlier in 2021 that included several new cybersecurity requirements for critical pipeline owners and operators. Among these requirements is the implementation of specific mitigation measures to protect against ransomware attacks and other known threats to information and operational technology systems; development and implementation of a cybersecurity contingency and recovery plan; and performance of a cybersecurity architecture design review. We have implemented several of these directives and are evaluating the potential effect of several others on our operations and facilities, as well as the potential cost of implementation, and will continue to monitor for any clarifications or amendments to these directives. Gas Pipeline and Storage Integrity and Safety We are subject to regulation by PHMSA, which requires the following for certain gas distribution and transmission pipelines and underground storage facilities: inspection and maintenance plans; integrity management programs, including the determination of pipeline integrity risks and periodic assessments on certain pipeline segments; an operator qualification program, which includes certain trainings; a public awareness program that provides certain information; and a control room management plan. If we fail to comply with applicable statutes and the PHMSA Office of Pipeline Safetys rules and related regulations and orders, we could be subject to significant penalties and fines. Environmental Matters We have clean energy goals to reduce GHG emissions that are based on prudent and proven solutions while minimizing cost impacts to and ensuring safety of our customers. See more information in Key Elements of our Business Strategy within Managements Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this Annual Report on Form 10-K. We are subject to significant state and federal environmental regulations that encourage the use of clean energy technologies and regulate emissions of GHGs. We have undertaken initiatives to meet current requirements and to prepare for anticipated future regulations, reduce GHG emissions, and respond to state renewable and energy efficiency goals. Compliance with future environmental regulations could result in substantial cost. In July of 2019, the EPA adopted the Affordable Clean Energy rule, which requires states to develop plans by 2022 for GHG reductions from coal-fired power plants. In a January 2021 decision, the U.S. Court of Appeals for the D.C. Circuit issued a decision vacating and remanding the Affordable Clean Energy rule. Four petitions for review of the D.C. Circuits opinion were subsequently granted by the U.S. Supreme Court on October 29, 2021, consolidated under West Virginia v. EPA et al. On June 30, 2022, the U.S. Supreme Court released its opinion in favor of West Virginia and aligned parties. The decision clarifies that there are limits on how the EPA may regulate GHGs absent further direction from the U.S. Congress. The court concluded that emission caps that would cause generation shifting from fossil-fuel-fired power plants to renewable energy facilities would require specific congressional authorization and that such authorization had not been given under the Clean Air Act. The decision by the U.S. Supreme Court may affect the EPAs development of any new regulations to address CO_2 emissions from coal- and natural gas-fired power plants; however, at this time, we cannot predict the impact of any such regulations or the decision by the U.S. Supreme Court on the results of operations, financial position, and liquidity. The EPA has indicated that it intends to issue a proposed rule in early 2023 with a new set of emission guidelines for states to follow in submitting state plans to establish and implement standards of performance for GHG emissions from existing fossil fuel-fired electric generating units. We will continue to monitor any related guidelines and rulemakings issued by the EPA or state regulatory authorities. In February 2022, the EPA proposed the Good Neighbor Rule Provisions, which are part of the CSAPR framework and is intended to address ozone transport for the 2015 ozone NAAQS. The rule focuses on reductions of NO_x, which is a precursor to ozone formation, for states that do not have an approved State Implementation Plan (SIP). On January 31, 2023, the EPA finalized a notice which disapproved 19 SIPs, partially disapproved two other SIPs and deferred action until December 2023 on two SIPs, which included Wyoming. The EPA action on January 31, 2023 was a necessary prerequisite for the EPA to finalize a proposed Good Neighbor Rule by the March 15, 2023 deadline. The EPA also released a new air quality modeling that indicated two states (including Wyoming), which were previously within scope of the Good Neighbor Rule, no longer exceeded the cross-state ozone emissions threshold. It is likely that the

EPA will rely on this new air quality modeling as part of the final Good Neighbor Rule. Based on the new air quality modeling, Wyoming will not be required to purchase additional NO x allowances during the 2023 ozone season. Until the EPA takes action on Wyoming's SIP, which is anticipated in December 2023, we cannot determine our future CSAPR compliance costs or impacts on our operations, but they could be material. However, we anticipate that any costs incurred as a result of the proposed rule would be recoverable through our regulatory mechanisms. Environmental risk changes constantly with the implementation of new or modified regulations, changing stakeholder interests and needs, and through the introduction of innovative work practices and technologies. We continually assess risk and develop mitigation strategies to manage and ensure compliance across the enterprise successfully and responsibly. For additional information on environmental matters, see Item 1A and Note 3 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K. Human Capital Resources Overview We are committed to supporting operational excellence by attracting, motivating, retaining and encouraging the development of a highly qualified and diverse employee team. Our employees drive and dedication to their work, and their commitment to the safety of our customers and their fellow employees, allows us to successfully grow and manage our business year over year. ##TABLE_START Our Team As of December 31, 2022 As of December 31, 2021 Total employees 2,982 2,884 Women in executive leadership positions (a) 33% 30% Gender diversity (women as a % of total employees) 25% 26% Represented by a union 25% 25% Military veterans 11% 14% Ethnic diversity (non-white employees as a % of total) 14% 12% For the year ended December 31, 2022 For the year ended December 31, 2021 Number of external hires External hires gender diversity (as a % of total external hires) 30% 25% External hires ethnic diversity (as a % of total external hires) 23% 20% Turnover rate (b) 13% 11% Retirement rate 3% 3% ##TABLE_END ____________________ (a) Executive leadership positions are defined as positions with Vice President, Senior Vice President or Chief in their title. (b) Includes voluntary and involuntary separations but excludes internships. Total Employees ##TABLE_START Number of Employees As of December 31, 2022 Electric Utilities Gas Utilities 1,226 Corporate and Other 1,314 Total 2,982 ##TABLE_END At December 31, 2022, approximately 19% of our total employees and 21% of our Electric and Gas Utilities employees were eligible for retirement (age 55 with at least 5 years of service). Collective Bargaining Agreements At December 31, 2022, certain employees of our Electric Utilities and Gas Utilities were covered by the collective bargaining agreements as shown in the table below. We have not experienced any labor stoppages in decades. ##TABLE_START Utility Number of Employees Union Affiliation Expiration Date of Collective Bargaining Agreement Colorado Electric IBEW Local 667 April 15, 2023 South Dakota Electric IBEW Local 1250 March 31, 2027 Wyoming Electric IBEW Local 111 June 30, 2024 Total Electric Utilities Iowa Gas IBEW Local 204 January 31, 2026 Kansas Gas Communications Workers of America, AFL-CIO Local 6407 December 31, 2024 Nebraska Gas IBEW Local 244 March 13, 2025 Nebraska Gas CWA Local 7476 October 30, 2023 Wyoming

Gas IBEW Local 111 June 30, 2024 Wyoming Gas CWA Local 7476 October 30, 2023 Total Gas Utilities Total ##TABLE_END Attraction Attracting talent to join our team is critical to our ability to serve over 1.3 million customers safely and efficiently. We continuously evaluate our recruitment strategies to determine their effectiveness to attract and build a high-performing, diverse workforce. Our diversity recruiting strategies support our efforts to attract qualified individuals with targeted efforts to reach underrepresented talent pools. Our internship program and our partnerships and participation in outreach programs with local schools and colleges attract students to careers in energy. Our commitment to equitable and inclusive hiring practices, including pay equity, further supports our vision of attracting, developing and retaining a high-performing workforce driven by improving life with energy. Diversity Inclusion We believe in the benefits of diversity, equity and inclusion. We believe that a diverse workforce will assist us in executing our strategic business plans, including our growth strategy. Workforce diversity trends, which include gender and diverse new hires, promotions and turnover, are monitored at regular intervals throughout the year. Development and Retention Retaining and developing team members is critical to our continued success. Our retention efforts include competitive compensation programs, monitoring employee engagement, career development resources for all employees and internal training programs. Our compensation programs are designed to be strategically aligned, externally competitive, internally equitable, personally motivating, cost effective and legally compliant. We continuously monitor employee engagement through bi-annual engagement surveys and quarterly pulse surveys. Every leader is responsible for creating and implementing an action plan based on their teams engagement survey results. Our career development resources include management onboarding, leadership development programs, mentoring programs, individual development assessments and more. Internal training opportunities include corporate-wide and specialized training opportunities for different job functions. Our Field Career Path Program (FCPP) promotes career growth through established standards of knowledge, skills, abilities and performance. Employee Safety and Wellness Safety is one of our company values, a top priority in all we do and deeply embedded in our culture. We are committed to consistently outperforming utility industry averages in key safety metrics. Meetings of three or more employees begin with a safety share, a practice which contributes to keeping safety top of mind. Since 2009, we have reduced workplace injuries by more than 75% and continue to see long-term, sustained improvements in our safety practices and performance. ##TABLE_START For the year ended December 31, 2022 Total Case Incident Rate (incidents per 200,000 hours worked) 1.39 Preventable Motor Vehicle Incident Rate (vehicle accidents per 1 million miles driven) 1.33 % of injuries reported within 1 day 90.8 % ##TABLE_END ITEM 1A. RISK FACTORS The nature of our business subjects us to a number of uncertainties and risks. Risks that may adversely affect our business operations, financial condition, results of operations or cash flows are described below. These risk factors, along with other risk factors that we discuss in our periodic reports filed with the SEC should be considered for a better understanding of our Company. STRATEGIC RISK Our continued success is dependent on execution of our business plan and growth strategy, including our capital investment program. Our continued success depends, in significant part, on our ability to execute our strategic business plans, including our growth strategy. Our plans and strategy include building sustainable operations and supporting the Energy Transition; consistently outperforming utility industry averages in key safety metrics; modernizing utility infrastructure; transforming the customer experience; growing our electric and natural gas customer load; and pursuing operational efficiencies. Our current plans and strategy may be negatively impacted by disruptive forces and innovations in the marketplace, workforce capabilities, changing political, business or regulatory conditions and technology advancements. In addition, we have significant capital investment programs planned for the next five years that are key to our strategic business plans. The successful execution of our capital investment program depends on, or could be affected by, a variety of factors that include, but are not limited to: availability of low cost capital to fund projects, weather conditions, effective management of projects, availability of qualified construction personnel including contractors, changes in commodity and other prices, impacts of supply chain disruptions on availability and cost of materials, governmental approvals and permitting, regulatory cost recovery and return on investment. An inability to successfully and timely adapt to changing conditions and execute our strategic plans could materially affect our financial operating results including earnings, cash flow and liquidity. REGULATORY, LEGISLATIVE AND LEGAL RISKS We may be subject to unfavorable or untimely federal and state regulatory outcomes. Our regulated Electric and Gas Utilities are subject to cost-of-service/rate-of-return regulation and earnings oversight from federal and eight state utility commissions. This regulatory treatment does not provide any assurance as to achievement of desired earnings levels. Our customer rates are regulated based on an analysis of our costs and investments, as reviewed and approved in regulatory proceedings. While rate regulation is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital, there can be no assurance that our various regulatory authorities will judge all of our costs to have been prudently incurred or that the regulatory process in which rates are determined will result in full or timely recovery of our costs with a reasonable return on invested capital. In addition, adverse rate decisions, including rate moratoriums, rate refunds, limits on rate increases, lower allowed returns on investments or rate reductions, could be influenced by competitive, economic, political, legislative, public perception and regulatory pressures and adversely impact earnings, cash flow and liquidity. Each of our Electric and Gas Utilities are permitted to recover certain costs (such as increased fuel and purchased power costs, including costs from certain severe weather events, or integrity capital investments) outside of a base rate review in order to stabilize customer rates and reduce regulatory lag. If regulators decide to discontinue these tariff-based recovery mechanisms, it could negatively impact earnings, cash flow and liquidity. Costs could significantly increase to achieve or maintain compliance with existing or future environmental laws, regulations or requirements including those associated with climate change. Our business segments are subject to numerous environmental laws and regulations affecting many aspects of present and future operations, including air emissions (i.e., SO_2 , NO_x , volatile organic compounds, particulate matter and GHG), water quality, wastewater discharges, solid waste and hazardous waste. These laws and regulations may result in increased capital, operating and other costs. These laws and regulations generally require the business segments to obtain and comply with a wide variety of environmental licenses, permits, inspections and other government approvals. Compliance with environmental laws and regulations may require significant expenditures, including expenditures for cleanup costs and damages arising from contaminated properties. Failure or inability to comply with evolving environmental regulations may result in the imposition of fines, penalties and injunctive measures affecting operating assets. Our business segments may not be successful in recovering increased capital and operating costs incurred to comply with new environmental regulations through existing regulatory rate structures and contracts with customers. More stringent environmental laws or regulations could result in additional costs of operation for existing facilities or impede the development of new facilities. There is significant uncertainty regarding if and when new climate legislation, regulations or administrative policies will be adopted to reduce or limit GHG and the impact any such regulations would have on us. New or more stringent regulations or other energy efficiency requirements could require us to incur significant additional costs relating to, among other things, the installation of additional emission control equipment, the acceleration of capital expenditures, the purchase of additional emissions allowances or offsets, the acquisition or development of additional energy supply from renewable resources, the closure or capacity reductions of coal-fired power generation facilities or conversion to natural gas, and potential increased production from our combined cycle natural gas-fired generating units. Additional rules and regulations associated with fossil fuels and GHG emissions could result in the impairment or retirement of some of our existing or future transmission, distribution, generation and natural gas storage facilities or our coal mine. Further, these rules could create the need to purchase or build clean-energy fuel sources to fulfill obligations to our customers. These actions could also result in increased operating costs which could adversely impact customers and our financial operating results including earnings, cash flow and liquidity. We cannot definitively estimate the effect of GHG legislation or regulation on our earnings, cash flow and liquidity. Legislative and regulatory requirements may result in compliance penalties. Business activities in the energy sector are heavily regulated, primarily by agencies of the federal government. Many agencies employ mandatory civil penalty structures for regulatory violations. The FERC, NERC, PHMSA, CFTC, EPA, OSHA, SEC, TSA and MSHA may impose significant civil and criminal penalties to enforce compliance requirements relative to our business, which could have a material adverse effect on our financial operating results including earnings, cash flow and liquidity. Municipal governments may seek to limit or deny our franchise privileges. Municipal governments within our utility service territories possess the power of condemnation and could establish a municipal utility within a portion of our current service territories by limiting or denying franchise privileges for our operations and exercising powers of condemnation over all or part of our utility assets within municipal boundaries. We regularly engage in negotiations on renewals of franchise agreements with our municipal governments. We have from time to time faced challenges or ballot initiatives on franchise renewals. To date, we have been successful in resolving or defending most of these challenges. Although condemnation is a process that is subject to constitutional protections requiring just and fair compensation, as with any judicial procedure, the outcome is uncertain. If a municipality sought to pursue this course of action, we cannot assure that we would secure adequate recovery of our investment in assets subject to condemnation. We also cannot quantify the impact that such action would have on the remainder of our business operations. Changes in Federal tax law may significantly impact our business. We are subject to taxation by the various taxing authorities at the federal, state and local levels where we operate. Sweeping legislation or regulation could be enacted by any of these governmental authorities which may affect our tax burden. Changes may include numerous provisions that affect businesses, including changes to corporate tax rates, business-related exclusions, and deductions and credits. The outcome of regulatory proceedings regarding the extent to which a change in corporate tax rate will affect our utility customers and the time period over which that change will occur could significantly impact future earnings and cash flows. Separately, a challenge by a taxing authority, changes in taxing authorities administrative interpretations, decisions, policies and positions, our ability to utilize tax benefits such as carryforwards or tax credits, or a deviation from other tax-related assumptions may cause actual financial results to deviate from previous estimates. Our business, financial condition, results of operations and prospects may be materially adversely affected due to adverse results of litigation. Material legal proceedings are summarized in Note 3 of Notes to Consolidated Financial Statement in this Annual Report on Form 10-K. Unfavorable resolution of legal or administrative proceedings in which we are involved or other future legal or administrative proceedings could have an adverse effect on our financial operating results, including earnings, cash flow and liquidity. OPERATING RISKS Failure to attract and retain an appropriately qualified workforce could have a negative impact on our operations and long-term business strategy. Recent trends, such as higher turnover, a competitive and tight labor market and an aging workforce may lead to higher costs and increased risk of negative outcomes for safety, compliance, customer service, and operations. Our ability to transition and replace our retirement-eligible utility employees is a risk; at December 31, 2022, approximately 19% of our employees were eligible for retirement. Our ability to avoid or minimize supply interruptions, work stoppages and labor disputes is also a risk with approximately 25% of our employees represented by unions. Failure to hire and retain qualified employees, including the ability to transfer significant internal historical knowledge and expertise to new employees, may adversely affect our ability to manage and operate our business. If we are unable to successfully attract and retain an appropriately qualified workforce and maintain satisfactory collective bargaining agreements, safety, service reliability, customer satisfaction and our results of operations could be adversely affected . Our plans and strategy include building sustainable operations and supporting the Energy Transition; consistently outperforming utility industry averages in key safety metrics; modernizing utility infrastructure; transforming the customer experience; growing our electric and natural gas customer load; and pursuing operating efficiencies. As part of our strategic plan, we will need to attract and retain personnel who are qualified to implement our strategy and may need to retrain or re-skill certain employees to support our long-term objectives. The nature of our business subjects us to climate-related risk, stemming from both physical risk and transition risk of climate change, over varying time horizons. Physical risks of climate change refer to risks to our facilities or operations that may result from changes in the physical climate, such as changes to temperature and weather patterns. Our utility businesses are seasonal businesses and weather conditions and patterns can have a material impact on our operating performance. To the extent weather conditions are affected by climate change, fluctuations in customers energy usage could be magnified. Climate change may lead to increased intensity and frequency of storms, resulting in increased likelihood of fire, wind and extreme temperature events. Severe weather events, such as snow and ice storms (e.g., Winter Storm Uri), fire, and strong winds could negatively impact our operations, including our ability to provide energy safely, reliably and profitably and our ability to complete construction, expansion or refurbishment of facilities as planned. Unmitigated impacts of climate change may intensify these events or increase the frequency of their occurrence. Over time, we may need to make additional investments to protect our facilities from physical risks of climate change. Transition risks of climate change include changes to the energy systems as a result of new technologies, changing customer demand and/or expectations and voluntary GHG reduction goals, as well as local, state or federal regulatory requirements (discussed above) intended to reduce GHG emissions. Policies such as a carbon or methane tax could increase costs associated with fossil fuel usage, resulting in higher operating costs including costs of energy generation, construction, and transportation. Risks of the transition to a low-carbon economy could result in shrinking customer demand for fossil fuel-based energy sources. This could come from increased use of behind the meter technology, such as residential solar and storage. Risk of investor pressure over climate risk and/or ESG standards, activist campaigns against coal producers, employee preferences to work for sustainable companies and consumers preference for renewable energy could impact our reputation and overall access to capital and/or adequate insurance policies. Supply chain challenges could negatively impact our operations. We rely on various suppliers in our supply chain for the materials necessary to execute on our capital investment program that is key to our strategic business plans and to respond to a significant unplanned event such as a natural disaster. Our largest customers also rely on our supply chain and delays in critical materials could impact their ability to operate and grow as planned. Our supply chain, material costs, and capital investment program may be negatively impacted by: Unanticipated price increases due to recent macroeconomic factors, such as inflation, including wage inflation, or rising demand for raw materials associated with the Energy Transition; and Supply restrictions beyond our control or the control of our suppliers such as disruption of the freight system (e.g. railroad labor union strikes), increased environmental threats from weather-related disasters, rising demand for raw materials associated with the Energy Transition and/or geopolitical unrest (e.g. Russian invasion of Ukraine). An inability to successfully manage challenges in our supply chain network could materially affect our financial operating results including earnings, cash flow and liquidity. Cyberattacks, terrorism, or other malicious acts targeting our key technology systems could disrupt our operations or lead to a loss or misuse of confidential and proprietary information. To effectively operate our business, we rely upon a sophisticated electronic control system, information and operation technology systems and network infrastructure to generate, distribute and deliver energy, and collect and retain sensitive information including personal information about our customers and employees. Cyberattacks, terrorism or other malicious acts targeting electronic control systems could result in a full or partial disruption of our electric and/or natural gas operations. Attacks targeting other key technology systems, including our third-party vendors information systems, could further add to a full or partial disruption of our operations. Recent geopolitical conflicts (e.g. Russia's invasion of Ukraine) have increased the risk of cyberattack. Any disruption of these operations could result in a loss of service to customers and associated revenues, as well as significant expense to repair damages and remedy security breaches. In addition, any theft, loss and/or fraudulent use of customer, shareowner, employee or proprietary data could subject us to significant litigation, liability and costs, as well as adversely impact our reputation with customers and regulators, among others. We maintain cyber risk insurance to mitigate a portion, but not all, of these risks and losses. As discussed in Utility Regulation Characteristics above, in 2021 the TSA issued security directives that included several new cybersecurity requirements for critical pipeline owners and operators. Such directives or other requirements may require expenditure of significant additional resources to respond to cyberattacks, to continue to modify or enhance protective measures, or to assess, investigate and remediate any critical infrastructure security vulnerabilities. Any failure to comply with such government regulations or failure in our cybersecurity protective measures may result in enforcement actions that may have a material adverse effect on our business, results of operations and financial condition. In addition, there is no certainty that costs incurred related to securing against threats will be recovered through rates. We have instituted security measures and safeguards to protect our operational systems and information technology assets, including certain safeguards required by FERC. Despite our implementation of security measures and safeguards, all of our technology systems may still be vulnerable to disability, failures or unauthorized access. Our financial performance depends on the successful operation of electric generating facilities, electric and natural gas transmission and distribution systems, natural gas storage facilities and a coal mine. The risks associated with managing these operations include: Operating hazards. Operating hazards such as leaks, mechanical problems and accidents, including fires or explosions, could impact employee and public safety, reliability and customer confidence; Inherent dangers. Electricity and natural gas can be dangerous to employees and the general public. Failures of or contact with power lines, natural gas pipelines or service facilities and equipment may result in fires, explosions, property damage and personal injuries, including death. While we maintain liability and property insurance coverage, such policies are subject to certain limits and deductibles. The occurrence of any of these events may not be fully covered by our insurance; Weather, natural conditions and disasters including impacts from climate change (discussed above); Acts of sabotage, terrorism or other malicious attacks. Damage to our facilities due to deliberate acts could lead to outages or other adverse effects; Equipment and processes. Breakdown or failure of equipment or processes, unavailability or increased cost of equipment, and performance below expected levels of output or efficiency could negatively impact our results of operations; Disrupted transmission and distribution. We depend on transmission and distribution facilities, including those operated by unaffiliated parties, to deliver the electricity and natural gas that we sell to our retail and wholesale customers. If transmission is interrupted physically, mechanically or with cyber means, our ability to sell or deliver utility services and satisfy our contractual obligations may be hindered; Natural gas supply for generation and distribution. Our regulated utilities and non-regulated entities purchase natural gas from a number of suppliers for our generating facilities and for distribution to our customers. Our results of operations could be negatively impacted by the lack of availability and cost of natural gas, and disruptions in the delivery of natural gas due to various factors, including but not limited to, transportation delays, labor relations, weather, sabotage, cyber-attacks and environmental regulations; Replacement power. The cost of supplying or securing replacement power during scheduled and unscheduled outages of generation facilities could negatively impact our results of operations; Governmental permits. The inability to obtain required governmental permits and approvals along with the cost of complying with or satisfying conditions imposed upon such approvals could negatively impact our ability to operate and our results of operations; Operational limitations. Operational limitations imposed by environmental and other regulatory requirements and contractual agreements, including those that restrict the timing of generation plant scheduled outages, could negatively impact our results of operations; Increased costs. Increased capital and operating costs to comply with increasingly stringent laws and regulations, unexpected engineering, environmental and geological problems, and unanticipated cost overruns could negatively impact our results of operations; Supply chain challenges (discussed above); Workforce capabilities and labor relations (discussed above); and Public opposition. Opposition by members of public or special-interest groups could negatively impact our ability to operate our businesses. Any of these risks described above could damage our reputation and public confidence. These risks could also cause us to incur significant costs or be unable to deliver energy and/or operate below expected capacity levels, which in turn could reduce revenues or cause us to incur higher operating and maintenance costs and penalties. While we maintain insurance, obtain warranties from vendors and obligate contractors to meet certain performance levels, the proceeds of such insurance and our rights under contracts, warranties or performance guarantees may not be timely or adequate to cover lost revenues, increased expenses, liability or liquidated damage payments. Our operations are subject to various conditions that can result in fluctuations in customer usage, including customer growth and general economic conditions in our service territories, weather conditions, and responses to price increases and technological improvements. Our results of operations and cash flows are affected by the demand for electricity and natural gas, which can vary greatly based upon: Fluctuations in customer growth and general economic conditions in our service territories. Customer growth and energy use can be negatively impacted by population declines as well as adverse economic factors in our service territories, including recession, inflation, workforce reductions, stagnant wage growth, changing levels of support from state and local government for economic development, business closings, and reductions in the level of business investment. Our utility businesses are impacted by economic cycles and the competitiveness of the commercial and industrial customers we serve. Any economic downturn, inflation, disruption of financial markets, or reduced incentives by state government for economic development could adversely affect the financial condition of our customers and demand for their products or services. These risks could directly influence the demand for electricity and natural gas as well as the need for additional power generation and generating facilities. We could also be exposed to greater risks of accounts receivable write-offs if customers are unable to pay their bills. Weather conditions. Our utility businesses are seasonal businesses and weather conditions and patterns can have a material impact on our operating performance. Demand for electricity is typically greater in the summer and winter months associated with cooling and heating, respectively. Demand for natural gas depends heavily upon winter-weather patterns throughout our service territory and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our utility operations have historically generated lower revenues, income and cash flows when weather conditions are cooler than normal in the summer and warmer than normal in the winter. Demand for natural gas is also impacted by summer weather patterns that are cooler than normal and provide higher than normal precipitation; both of which can reduce natural gas demand for irrigation. Unusually mild summers and winters, therefore, could have an adverse effect on our financial operating results, including earnings, cash flow and liquidity. Our customers' focus on energy conservation. Customer growth and usage may be impacted by the voluntary reduction in consumption of electricity and natural gas by our customers in response to increases in prices and energy efficiency programs, electrification initiatives that could negatively impact the demand for natural gas, economic conditions (i.e., inflation, recession) impacting customers disposable income and the use of distributed generation resources or other emerging technologies. Continued technological improvements may make customer and third-party distributed generation and energy storage systems, including fuel cells, micro-turbines, wind turbines, solar cells and batteries, more cost effective and feasible for our customers. If more customers utilize their own generation, demand for energy from us could decline. Such developments could affect the price of energy and delivery of energy, require further improvements to our distribution systems to address changing load demands and could make portions of our electric system power supply and transmission and/or distribution facilities obsolete prior to the end of their useful lives. Each of these factors described above could materially affect demand for electricity and natural gas which would impact our financial operating results including earnings, cash flow and liquidity. If macroeconomic or other conditions adversely affect operations or require us to make changes to our strategic business plan, we may be forced to record a non-cash goodwill impairment charge. We had approximately $1.3 billion of goodwill on our consolidated balance sheets as of December 31, 2022. If we make changes in our strategic business plan and growth strategy, or if macroeconomic or other conditions adversely affect operations in any of our businesses, we may be forced to record a non-cash impairment charge. Goodwill is tested for impairment annually or whenever events or changes in circumstances indicate impairment may have occurred. If the testing performed indicates that impairment has occurred, we are required to record an impairment charge for the difference between the carrying value of the goodwill and the implied fair value of the goodwill in the period the determination is made. The testing of goodwill for impairment requires us to make significant estimates about our future performance and cash flows, as well as other assumptions. These estimates can be affected by numerous factors, including: future business operating performance, changes in macroeconomic conditions including recession, inflation and interest rates, changes in our regulatory environment, industry-specific market conditions, changes in business operations, changes in competition or changes in technologies. Any changes in key assumptions, or actual performance compared with key assumptions, about our business and its future prospects could affect the fair value of either or both of our operating segments, which may result in an impairment charge. See additional information in Critical Accounting Estimates under Item 7 , Managements Discussion and Analysis of Financial Condition and Results of Operations and Note 1 of the Notes to Consolidated Financial Statements in this Annual Report on Form 10-K. Widespread public health crises and epidemics or pandemics could negatively affect our business operations, results of operations, financial condition and cash flows. We are subject to the impacts of widespread public health crises, epidemics and pandemics, including, but not limited to, impacts on the global, national or local economies, capital and credit markets, our workforce, customers and suppliers. There is no assurance that our businesses will be able to operate without material adverse impacts depending on the nature of the public health crisis, epidemic or pandemic. The ultimate severity, duration and impact of public health crises, epidemics and pandemics cannot be predicted. Additionally, there is no assurance that vaccines, or other treatments, are or will be widely available or effective, or that the public will be willing to participate, in an effort to contain the spread of disease. Actions taken in response to such crises by federal, state and local government or regulatory agencies may adversely affect our financial operating results including earnings, cash flow and liquidity. FINANCIAL RISKS A sub-investment grade credit rating could impact our ability to access capital markets. Our senior unsecured debt rating is Baa2 (Stable outlook) by Moodys; BBB+ (Stable outlook) by SP; and BBB+ (Stable outlook) by Fitch. Reduction of our investment grade credit ratings could impair our ability to refinance or repay our existing debt and complete new financings on reasonable terms. A credit rating downgrade, particularly to sub-investment grade, could also result in counterparties requiring us to post additional collateral under existing or new contracts. In addition, a ratings downgrade would increase our interest expense under some of our existing debt obligations, including borrowings under our credit facilities, potentially significantly increasing our cost of capital and other associated operating costs which may not be recoverable through existing regulatory rate structures and contracts with customers. We may be unable to obtain financing on reasonable terms needed to refinance debt, fund planned capital expenditures or otherwise execute our operating strategy. Our ability to execute our operating strategy is highly dependent upon our access to capital. Historically, we have addressed our liquidity needs (including funds required to make scheduled principal and interest payments, refinance debt, pay dividends and fund working capital and planned capital expenditures) with operating cash flow, borrowings under credit facilities, proceeds of debt and equity offerings and proceeds from asset sales. Our ability to access capital markets and the costs and terms of available financing depend on many factors, including changes in our credit ratings, general macroeconomic conditions which may drive changes in interest rates and cause volatility in our stock price, changes in the federal or state regulatory environment affecting energy companies and volatility in commodity prices. In addition, because we are a holding company and our utility assets are owned by our subsidiaries, if we are unable to adequately access the credit markets, we could be required to take additional measures designed to ensure that our utility subsidiaries are adequately capitalized to provide safe and reliable service. Possible additional measures would be evaluated in the context of then-prevailing market conditions, prudent financial management and any applicable regulatory requirements. Our use of derivative financial instruments as hedges against commodity prices and financial market risks could result in material financial losses. We use various financial and physical derivatives, including futures, forwards, options and swaps, to manage commodity price and interest rate risks. The timing of the recognition of gains or losses on these economic hedges in accordance with GAAP may not consistently match up with the gains or losses on the commodities being hedged. For Black Hills Energy Services under the Choice Gas Program, and in certain instances within our regulated Utilities where unrealized and realized gains and losses from derivative instruments are not approved for regulatory accounting treatment, fluctuating commodity prices may cause fluctuations in reported financial results due to mark-to-market accounting treatment. To the extent that we hedge our commodity price and interest rate exposures, we forgo the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor. In addition, even though they are closely monitored by management, our hedging activities can result in losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the hedge arrangement, the hedge is economically imperfect, commodity prices or interest rates move unfavorably related to our physical or financial positions, or hedging policies and procedures are not followed. Additionally, our exchange-traded futures contracts are subject to futures margin posting requirements. To the extent we are unable to meet these requirements, this could have a significant impact on our business by reducing our ability to execute derivative transactions to reduce commodity price uncertainty and to protect cash flows. Requirements to post collateral may cause significant liquidity issues by reducing our ability to use cash for investment or other corporate purposes or may require us to increase our level of debt. Further, a requirement for our counterparties to post collateral could result in additional costs being passed on to us, thereby decreasing our profitability. We have a holding company corporate structure with multiple subsidiaries. Corporate dividends and debt payments are dependent upon cash distributions to the holding company from the subsidiaries. As a holding company, our investments in our subsidiaries are our primary assets. Our operating cash flow and ability to service our indebtedness depend on the operating cash flow of our subsidiaries and the payment of funds by them to us in the form of dividends or advances. Our subsidiaries are separate legal entities that have no obligation to make any funds available for that purpose, whether by dividends or otherwise. In addition, each subsidiarys ability to pay dividends to us depends on any applicable contractual or regulatory restrictions that may include requirements to maintain minimum levels of cash, working capital, equity or debt service funds. There is no assurance as to the amount, if any, of future dividends to the holding company because these subsidiaries depend on future earnings, capital requirements and financial conditions to fund such dividends. See Liquidity and Capital Resources within Managements Discussion and Analysis of Financial Condition and Results of Operations in Item 7 and Note 8 of the Notes to Consolidated Financial Statements of this Annual Report on Form 10-K for further information regarding these restrictions and their impact on our liquidity. We may be unable to obtain insurance coverage, and the coverage we currently have may not apply or may be insufficient to cover a significant loss. Our ability to obtain insurance, as well as the cost of such insurance, could be impacted by developments affecting the insurance industry and the financial condition of insurers. Additionally, insurance providers could deny coverage or decline to extend coverage under the same or similar terms that are presently available to us. A loss for which we are not adequately insured could materially affect our financial results. The coverage we currently have in place may not apply to a particular loss, or it may not be sufficient to cover all liabilities to which we may be subject, including liability and losses associated with wildfires, natural gas and storage field explosions, cyber-security breaches, environmental hazards and natural disasters. Market performance or changes in key valuation assumptions could require us to make significant unplanned contributions to our pension plan and other postretirement benefit plans. Assumptions related to interest rates, expected return on investments, mortality and other key actuarial assumptions have a significant impact on our funding requirements and the expense recognized related to our pension and other postretirement benefit plans. An adverse change to key assumptions associated with our defined benefit retirement plans may require significant unplanned contributions to the plans which could adversely affect our financial operating results including earnings, cash flow and liquidity. See Note 8 of the Notes to Consolidated Financial Statements of this Annual Report on Form 10-K for further information Costs associated with our healthcare plans and other benefits could increase significantly. The costs of providing healthcare benefits to our employees and retirees have increased substantially in recent years. We believe that our employee benefit costs, including costs related to healthcare plans for our employees and former employees, will continue to rise. Significant regulatory developments have required, and likely will continue to require, changes to our current employee benefit plans and supporting administrative processes. Our electric and natural gas utility rates are regulated on a state-by-state basis by the relevant state regulatory authorities based on an analysis of our costs, as reviewed and approved in a regulatory proceeding. Within our utility rates, we have generally recovered the cost of providing employee benefits. As benefit costs continue to rise, however, there is no assurance that the utility commissions will allow recovery of these increased costs. The rising employee benefit costs, or inadequate recovery of such costs, may adversely affect our financial operating results including earnings, cash flow, or liquidity.

Ticker: CWT, Sector: Utilities, Filed At: 2023-03-01T16:24:14-05:00

Item 1. Business. Forward-Looking Statements This annual report, including all documents incorporated by reference, contains forward-looking statements within the meaning established by the Private Securities Litigation Reform Act of 1995 (the PSLRA). The forward-looking statements are intended to qualify under provisions of the federal securities laws for "safe harbor" treatment established by the PSLRA. Forward-looking statements in this annual report are based on currently available information, expectations, estimates, assumptions and projections, and our management's beliefs, assumptions, judgments and expectations about us, the water utility industry and general economic conditions. These statements are not statements of historical fact. When used in our documents, statements that are not historical in nature, including words like "will," "would," expects, intends, plans, believes, may, "could," estimates, assumes, anticipates, projects, "progress," predicts, "hopes," "targets," forecasts, should, seeks, "indicates," or variations of these words or similar expressions are intended to identify forward-looking statements. Examples of forward-looking statements in this annual report include, but are not be limited to, statements describing our intention, indication or expectation regarding dividends, retained earnings or targeted payout ratio, our expectations, anticipations or beliefs regarding governmental, legislative, judicial, administrative or regulatory timelines, decisions, approvals, authorizations, requirements or other actions, including with respect to the 2021 GRC Filing, our cost of capital application, rate amounts or cost recovery mechanics or climate change legislation or regulations, and associated impacts, our intentions regarding expansion opportunities, estimates of, or expectations regarding, capital expenditures, funding needs or other capital requirements, obligations or commitments, our beliefs regarding adequacy of water supplies, anticipated renewal of contracts, anticipated or estimated prices or amounts of water, our commitments or expectations regarding our human capital resources, our intentions regarding use of net proceeds from any future equity issuances or our intentions regarding our capital structure or capital allocation plans. The forward-looking statements are not guarantees of future performance. They are based on numerous assumptions that we believe are reasonable, but they are open to a wide range of uncertainties and business risks. Consequently, actual results may vary materially from what is contained in a forward-looking statement. Factors which may cause actual results to be different than those expected or anticipated include, but are not limited to: the impact of the ongoing COVID-19 pandemic and related public health measures; our ability to invest or apply the proceeds from the issuance of common stock in an accretive manner; governmental and regulatory commissions' decisions, including decisions on proper disposition of property; consequences of eminent domain actions relating to our water systems; changes in regulatory commissions' policies and procedures, such as the California Public Utilities Commission (CPUC)s decision in 2020 to preclude companies from proposing fully decoupled WRAMs in their next GRC filing (which impacted our 2021 GRC Filing related to our operations commencing in 2023); the outcome and timeliness of regulatory commissions' actions concerning rate relief and other matters, including with respect to our 2021 GRC Filing and our Cost of Capital filing; increased risk of inverse condemnation losses as a result of climate change and drought; our ability to renew leases to operate water systems owned by others on beneficial terms; changes in California State Water Resources Control Board water quality standards; changes in environmental compliance and water quality requirements; electric power interruptions, especially as a result of Public Safety Power Shutoff (PSPS) programs; housing and customer growth; the impact of opposition to rate increases; our ability to recover costs; availability of water supplies; issues with the implementation, maintenance or security of our information technology systems; civil disturbances or terrorist threats or acts; the adequacy of our efforts to mitigate physical and cyber security risks and threats; the ability of our enterprise risk management processes to identify or address risks adequately; labor relations matters as we negotiate with the unions; changes in customer water use patterns and the effects of conservation, including as a result of drought conditions; our ability to complete, in a timely manner or at all, successfully integrate, and achieve anticipated benefits from announced acquisitions; the impact of weather, climate change, natural disasters, and actual or threatened public health emergencies, including disease outbreaks, on our operations, water quality, water availability, water sales and operating results and the adequacy of our emergency preparedness; restrictive covenants in or changes to the credit ratings on our current or future debt that could increase our financing costs or affect our ability to borrow, make payments on debt or pay dividends; risks associated with expanding our business and operations geographically; the impact of stagnating or worsening business and economic conditions, including inflationary pressures, general economic slowdown or a recession, increasing interest rates, and changes in monetary policy; the impact of market conditions and volatility on unrealized gains or losses on our non-qualified benefit plan investments and our operating results; the impact of weather and timing of meter reads on our accrued unbilled revenue; and the risks set forth in "Risk Factors" included elsewhere in this annual report. In light of these risks, uncertainties and assumptions, investors are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date of this annual report or as of the date of any document incorporated by reference in this annual report, as applicable. When considering forward-looking statements, investors should keep in mind the cautionary statements in this annual report and the documents incorporated by reference. We are not under any obligation, and we expressly disclaim any obligation, to update or alter any forward-looking statements, whether as a result of new information, future events or otherwise. Overview California Water Service Group is a holding company with seven operating subsidiaries: California Water Service Company (Cal Water), New Mexico Water Service Company (New Mexico Water), Washington Water Service Company (Washington Water), Hawaii Water Service Company, Inc. (Hawaii Water), TWSC, Inc. (Texas Water), and CWS Utility Services and HWS Utility Services LLC (CWS Utility Services and HWS Utility Services LLC being referred to collectively in this annual report as Utility Services). Cal Water, New Mexico Water, Washington Water, and Hawaii Water are regulated public utilities. Texas Water holds regulated and contracted wastewater utilities. The regulated utility entities also provide some non-regulated services. Utility Services holds non-utility property and provides non-regulated services to private companies and municipalities outside of California (see Non-Regulated Activities below for more details). Cal Water was the original operating company and began operations in 1926. Our business is conducted through our operating subsidiaries and we provide utility services to approximately two million people. The bulk of the business consists of the production, purchase, storage, treatment, testing, distribution and sale of water for domestic, industrial, public and irrigation uses, and the provision of domestic and municipal fire protection services. In some areas, we provide wastewater collection and treatment services, including treatment which allows water recycling. We also provide non-regulated water-related services under agreements with municipalities and other private companies. The non-regulated services include full water system operation, billing and meter reading services. Non-regulated operations also include the lease of communication antenna sites, lab services and promotion of other non-regulated services. During the year ended December 31, 2022, there were no significant changes in the kind of products produced or services rendered by our operating subsidiaries, or in the markets or methods of distribution. Our mailing address and contact information is: California Water Service Group 1720 North First Street San Jose, California 95112-4598 Telephone number: 408-367-8200 www.calwatergroup.com Annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to these reports are available free of charge through our website at www.calwatergroup.com. The reports are available on our website as soon as reasonably practicable after such reports are filed with the SEC. The content on any website referred to in this annual report is not incorporated by reference in this annual report unless expressly noted. Regulated Business California water operations are conducted by Cal Water, which provides service to approximately 496,400 customer connections in approximately 100 California communities through 21 separate districts, which are subject to regulation by the CPUC. California water operations accounted for approximately 89.8% of our total customer connections and 91.6% of our total consolidated operating revenue. We operate the City of Hawthorne and the City of Commerce water systems under lease agreements. In accordance with the lease agreements, we receive all revenues from operating the systems and are responsible for paying the operating costs. The City of Hawthorne and the City of Commerce lease revenues are governed through their respective city councils and are considered non-regulated because they are outside of the CPUC's jurisdiction. We report revenue and expenses for the City of Hawthorne and City of Commerce leases in operating revenue and operating expenses because we are entitled to retain all customer billings and are responsible for all operating expenses. These leases are considered "nontariffed products and services" (NTPS) by the CPUC and require a 10% revenue sharing with regulated customers. In October of 2011, an agreement was negotiated with the City of Hawthorne to lease and operate its water system. The system, which is located near the Hermosa Redondo district, serves about half of Hawthorne's population. The capital lease agreement required an up-front $8.1 million lease deposit to the city that is being amortized over the lease term. Additionally, annual lease payments are contracted to be adjusted based on changes in rates charged to customers. Under the lease, we are responsible for all aspects of system operation and capital improvements, although title to the system and system improvements reside with the city. Capital improvements are recorded as depreciable plant and equipment and depreciated per the asset lives set forth in the agreement. In exchange, we receive all revenue from the water system, which was $12.5 million, $11.4 million, and $10.5 million in 2022, 2021, and 2020, respectively. At the end of the lease, the city is required to reimburse us for the unamortized value of capital improvements made during the term of the lease. The City of Hawthorne capital lease is a 15-year lease and expires in 2026. In April of 2018, a renewal agreement was negotiated with the City of Commerce for us to continue to lease and to operate its water system for 15 years. Under the agreement, the operating lease requires us to pay $0.8 million per year in monthly installments. We have operated the City of Commerce water system since 1985 and are responsible for all operations, maintenance, water quality assurance, customer service programs, and financing capital improvements to provide a reliable supply of water that meets federal and state standards to customers served by the City of Commerce system. The City of Commerce retains title to the system and system improvements and remains responsible for setting its customers water rates. We bear the risks of operation and collection of amounts billed to customers. In exchange, we receive all revenue from the water system, which was $4.2 million, $3.4 million, and $2.9 million in 2022, 2021, and 2020, respectively. The agreement allows us to request a rate change annually in order to recover costs. Hawaii Water provides service to approximately 6,200 water and wastewater customer connections on the islands of Maui, Oahu, and Hawaii, including several large resorts and condominium complexes. Hawaii Water's regulated customer connections are subject to the jurisdiction of the Hawaii Public Utilities Commission (HPUC). Hawaii Water accounts for 1.1% of our total customer connections and approximately 4.9% of our total consolidated operating revenue. Washington Water provides domestic water service to approximately 37,500 customer connections in the Tacoma, Olympia, Graham, Spanaway, Puyallup, Rainier, Yelm, and Gig Harbor areas. Washington Water's utility operations are regulated by the Washington Utilities and Transportation Commission. Washington Water accounts for approximately 6.8% of our total customer connections and approximately 2.6% of our total consolidated operating revenue. New Mexico Water provides service to approximately 10,700 water and wastewater customer connections in the Belen, Farmington, Los Lunas, Indian Hills, and Elephant Butte areas in New Mexico. New Mexico's regulated operations are subject to the jurisdiction of the New Mexico Public Regulation Commission (NMPRC). New Mexico Water accounts for approximately 1.9% of our total customer connections and 0.7% of our total consolidated operating revenue. In May of 2021, Texas Water became the majority owner of BVRT Utility Holding Company (BVRT), a Texas-based utility development company owning and operating four wastewater utilities serving growing communities outside of Austin and San Antonio. Texas Water initially invested funds to enable BVRT to continue to build wastewater infrastructure and converted its investment to equity. BVRTs five wastewater utilities currently serve or are under contract to serve over 2,200 customer connections. On August 16, 2022, BVRT entered into a long-term water supply agreement with the Guadalupe Blanco River Authority (GBRA) that enables BVRT to receive up to 2,419 acre-feet of potable water annually (see Note 14 for more details). Texas Water accounts for approximately 0.4% of our total customer connections and 0.2% of our total consolidated operating revenue. The state regulatory bodies governing our regulated operations are referred to as the Commissions in this annual report. Rates and operations for regulated customers are subject to the jurisdiction of the respective state's regulatory Commission. The Commissions require that water and wastewater rates for each regulated district are independently determined based on the cost of service. The Commissions are expected to authorize rates sufficient to recover normal operating expenses and allow the utility to earn a fair and reasonable return on invested capital. We distribute and treat water and treat wastewater in accordance with accepted water utility methods. Where applicable, we hold franchises and permits in the cities and communities where we operate. The franchises and permits allow us to operate and maintain facilities in public streets and rights-of-way as necessary. Non-Regulated Activities Non-regulated revenue and expenses consist primarily of the operation of water systems that are owned by other entities under lease agreements, leasing of communication antenna sites on our properties, billing of optional third-party insurance programs to our residential customers, and unrealized gains or losses on benefit plan investments. Fees for non-regulated activities are based on contracts negotiated between the parties. Under our non-regulated contract arrangements, we operate municipally owned water systems and privately owned water and recycled water distribution systems, but are not responsible for all operating costs. Non-regulated revenue received from non-leased water system operations is generally determined on a fee-per-customer basis. In California, nearly all non-regulated activities are considered NTPS. The prescribed accounting for these NTPS is incremental cost allocation plus revenue sharing with regulated customers. Non-regulated services determined to be "active activities" require a 10% revenue sharing, and "passive activities" require a 30% revenue sharing. The amount of non-regulated revenues subject to revenue sharing is the total billed revenues less any authorized pass-through costs. Some examples of CPUC authorized pass-through costs are purchased water, purchased power, and pump taxes. All of our non-regulated services, except for leasing communication antenna sites on our properties, are "active activities" subject to a 10% revenue sharing. Leasing communication antenna sites on our properties are "passive activities" subject to a 30% revenue sharing. Cal Water's annual revenue sharing with regulated customers was $2.7 million, $3.1 million, and $2.5 million in 2022, 2021, and 2020, respectively. Operating Segment We operate in one reportable segment, the supply and distribution of water and providing water-related utility services. For information about revenue from external customers, net income attributable to California Water Service Group and total assets, see "Item 8. Financial Statements and Supplementary Data." Growth We intend to continue exploring opportunities to expand our regulated and non-regulated water and wastewater activities, particularly in the western United States. The opportunities could include system acquisitions, lease arrangements similar to the City of Hawthorne and City of Commerce contracts, utility development investments similar to the BVRT investment, full service system operation and maintenance agreements, meter reading, billing contracts and other utility-related services. Geographical Service Areas and Number of Customer Connections at Year-end Our principal markets are users of water within our service areas. The approximate number of customer connections served in each regulated district, the City of Hawthorne and the City of Commerce, at December 31 is as follows: ##TABLE_START (rounded to the nearest hundred) 2022 2021 SAN FRANCISCO BAY AREA/NORTH COAST Bay Area Region (serving South San Francisco, Colma, Broadmoor, San Mateo, San Carlos, Lucerne, Duncans Mills, Guerneville, Dillon Beach, Noel Heights and portions of Santa Rosa) 56,000 56,000 Bear Gulch (serving portions of Menlo Park, Atherton, Woodside and Portola Valley)

19,000 19,000 Los Altos (including portions of Cupertino, Los Altos Hills, Mountain View and Sunnyvale) 19,000 19,000 Livermore 19,000 19,000 113,000 113,000 SACRAMENTO VALLEY Chico (including Hamilton City) 31,300 31,100 Oroville 3,700 3,700 Marysville 3,800 3,800 Dixon 3,100 3,100 Willows 2,400 2,400 44,300 44,100 SALINAS VALLEY Salinas Valley Region (including Salinas and King City) 31,700 31,700 31,700 31,700 SAN JOAQUIN VALLEY Bakersfield 74,100 73,700 Stockton 45,200 44,900 Visalia 48,100 47,400 Selma 6,600 6,600 Kern River Valley 4,100 4,000 178,100 176,600 LOS ANGELES AREA East Los Angeles 27,000 27,000 Hermosa Redondo (serving Hermosa Beach, Redondo Beach and a portion of Torrance) 27,200 27,200 Dominguez (Carson and portions of Compton, Harbor City, Long Beach, Los Angeles and Torrance) 34,400 34,400 Los Angeles County Region (including Palos Verdes Estates, Rancho Palos Verdes, Rolling Hills Estates, Rolling Hills, Fremont Valley, Lake Hughes, Lancaster and Leona Valley) 25,900 25,800 Westlake (a portion of Thousand Oaks) 7,100 7,100 Hawthorne and Commerce (leased municipal systems) 7,700 7,600 129,300 129,100 CALIFORNIA TOTAL 496,400 494,500 HAWAII 6,200 6,200 NEW MEXICO 10,700 8,600 WASHINGTON 37,500 36,400 TEXAS 2,200 1,900 COMPANY TOTAL 553,000 547,600 ##TABLE_ENDRates and Regulation The Commissions have plenary powers setting both rates and operating standards. As such, the Commissions' decisions significantly impact the Company's revenues, earnings, and cash flows. The amounts discussed herein are generally annual amounts, unless otherwise stated, and the financial impact to recorded revenue is expected to occur over a 12-month period from the effective date of the decision. In California, water utilities are required to make several different types of filings. Certain filings, such as General Rate Case (GRC) filings, escalation rate increase filings, and offset filings, may result in rate changes that generally remain in place until the next GRC. As explained below, surcharges and surcredits to recover balancing and memorandum accounts as well as GRC interim rate relief are temporary rate changes, having specific time frames for recovery. The CPUC follows a rate case plan which requires Cal Water to file a GRC for each of its regulated operating districts (except Grand Oaks) every three years. In a GRC proceeding the CPUC not only considers the utility's rate setting requests, but may also consider other issues that affect the utility's rates and operations. The CPUC is generally required to issue its GRC decision prior to the first day of the test year or authorize interim rates and an Interim Rates Memorandum Account (IRMA) or just an IRMA. In accordance with the rate case plan, Cal Water filed its most recent GRC filing in July of 2021 (2021 GRC Filing) requesting rate changes effective January 1, 2023. For additional information on our 2021 GRC Filing, see "Regulatory Activity - California". Between GRC filings, Cal Water may file escalation rate increases, which allow Cal Water to recover cost increases, primarily from inflation and incremental investments, generally during the second and third years of the rate case cycle. However, escalation rate increases are district specific and subject to an earnings test. The CPUC may reduce a districts escalation rate increase if, in the most recent 13-month period, the earnings test reflects earnings in excess of what was authorized for that district. In addition, California water utilities are entitled to make offset requests via advice letter. Offsets may be requested to adjust revenues for construction projects authorized in GRCs or recycled water projects when those capital projects go into service (these filings are referred to as "rate base offsets"), or for rate changes charged to Cal Water for purchased water, purchased power, and pump taxes (which are referred to as "expense offsets"). Rate changes approved in offset requests remain in effect until the next GRC is approved. In pursuit of the State of California's water conservation goals, the CPUC decoupled Cal Water's revenue requirement from customer consumption levels in 2008 by authorizing a Water Revenue Adjustment Mechanism (WRAM) and Modified Cost Balancing Account (MCBA) for each district. The WRAM and MCBA were designed to ensure that Cal Water recovers revenues authorized by the CPUC regardless of customer consumption. This removed the historical disincentive against promoting lower water usage among customers. Through an annual advice letter filing, Cal Water can seek to recover any under-collected metered revenue amounts authorized, or refunds over-collected metered revenues, via surcharges and surcredits. The advice letters generally have been filed in April of each year and addressed the net WRAM and MCBA balances recorded for the previous calendar year. The majority of WRAM and MCBA balances have been collected or refunded through surcharges/surcredits over 12 and 18 months. The WRAM and MCBA amounts have been cumulative, so if they were not amortized in a given calendar year, the balance was carried forward and included with the following year balance. Cal Water also had a Sales Reconciliation Mechanism (SRM) in place for 2021 and 2022 (the second and third years of its 2018 GRC), that allowed the company to adjust its adopted sales forecast if actual sales vary from adopted sales by more than 5.0% in the prior year in a district. The SRM moderates the growth of the net WRAM and MCBA balances until the next GRC. The CPUC issued a decision effective August 27, 2020 requiring that Class A companies submitting GRC filings after the effective date be (i) precluded from proposing the use of a full decoupling WRAM in their next GRCs and (ii) allowed the use of Monterey-Style Water Revenue Adjustment Mechanisms (MWRAM). In addition, the CPUC's decision allowed for Incremental Cost Balancing Accounts (ICBAs), which are authorized by state statute, to replace the MCBA. The MWRAM tracks the difference between the revenue received for actual metered sales through the tiered volumetric rate and the revenue that would have been received with the same actual metered sales if a uniform rate had been in effect. The ICBA tracks differences between the authorized per-unit prices of water production costs and actual per-unit prices of water production costs. Cal Water complied with this decision in its 2021 GRC Filing and expects these replacement mechanisms to be in effect for 2023. In September 2020, Cal Water filed an Application for Rehearing at the CPUC seeking to reverse the August 27, 2020 CPUC decision. While a decision was pending on the Application for Rehearing, Cal Water along with four other Class A California water utilities filed Petitions for a Writ of Review with the California Supreme Court (Court) on or about October 27, 2021. In September 2021, the CPUC denied the Application for Rehearing.

On May 18, 2022, the Court issued writs granting review and ordered the CPUC and other filing parties to submit additional pleadings to the Court. The final pleadings were submitted on January 13, 2023. Cal Water anticipates that the Court will schedule an oral argument before it begins deliberations and issues its decision. Regulatory Activity - California 2021 GRC Filing and Interim Rates Memorandum Account (IRMA) On July 2, 2021, Cal Water filed its 2021 GRC requesting water infrastructure improvements of $1.0 billion in accordance with the rate case plan for all of its regulated operating districts (except Grand Oaks) for the years 2022, 2023, and 2024. The CPUC continues to evaluate the water infrastructure improvements along with operating budgets to establish water rates that reflect the actual cost of service. The CPUC also continues to evaluate Cal Water's proposed rate design changes that would improve revenue stability and provide a discounted unit rate to the first six units of water per month for residential customers. In the proposal, this block of usage would be charged at 25% of the second tier rate. The CPUC has recognized this six-unit block as essential for basic needs. As part of the rate design changes, Cal Water has proposed the use of a MWRAM and ICBA. The required filing was the start of an approximately 18-month review process, with any changes in customer rates scheduled to become effective on January 1, 2023. Cal Water proposed to the CPUC to increase revenues by $80.5 million, or 11.1%, in 2023; $43.6 million, or 5.4%, in 2024; and $43.2 million, or 5.1%, in 2025 to support these investments. If approved as filed, we expect that the average residential customer bill would increase less than $5 per month across all of Cal Waters service areas. California Public Advocates Office, an independent consumer advocate at the CPUC, reviewed Cal Water's 2021 GRC Filing and submitted its report in February 2022. Cal Water reviewed California Public Advocates Office recommendations, evaluated the validity of the underlying data, and composed and filed rebuttal testimony with the CPUC in April 2022. Settlement negotiations with the California Public Advocates Office and intervenors began in the second quarter of 2022 and evidentiary hearings were held in the second quarter of 2022. A partial settlement with the California Public Advocates Office primarily addressing non-revenue matters was submitted on September 2, 2022. One intervenor submitted comments on the settlement on September 30, 2022, to which Cal Water filed a response. The CPUC continues to evaluate the proposal along with proposals of other parties. A final decision on the case was previously expected to be issued in late 2022 in accordance with the CPUC's Rates Case Plan, with new rates going into effect on January 1, 2023; however, due to unspecified delays at the CPUC, the timing of a final decision is uncertain. In January 2023, the CPUC issued a decision extending its statutory deadline until July 3, 2023. Normally, the CPUC is subject to a requirement to process applications within 18 months of filing. In our experience, it is the CPUC's practice to extend its statutory deadline, in some cases multiple times, as needed. If the partial settlement is not approved or is approved on terms less favorable to us, such approval or decision could have a material adverse impact on our revenue, operating results and earnings per share. Even if the partial settlement is approved on its current terms, there could be a material adverse impact on our revenue, operating results, and earnings per share on an interim basis if the case is materially delayed. However, we would expect this to be reversed at the time of a final decision through recognition of interim rate recovery. In June of 2022, Cal Water filed a motion requesting authority to increase rates by inflation on January 1, 2023 and for the establishment of an IRMA in the event the CPUC does not issue a final decision for the 2021 GRC Filing in time for new rates to be implemented on January 1, 2023. In November of 2022, the Administrative Law Judge (ALJ) assigned to evaluate the motion granted Cal Waters request for the IRMA but did not authorize the inflation rate increase. Accordingly, on December 27, 2022, Cal Water requested that the IRMA, which was approved by the CPUC, track the difference between the current rates that continue to be billed starting January 1, 2023 (considered to be interim rates), and the rates that will eventually be approved pursuant to the CPUC's decision concerning Cal Water's 2021 GRC Filing plus any additional revenue changes approved since July 1, 2021 (final rates). After the CPUC's decision is issued and final rates are implemented, then we would expect the balance in the IRMA to be reviewed, and customer bills to be adjusted to account for the difference between interim rates and final rates back to January 1, 2023. In January of 2023, Cal Water filed a motion requesting a modification to the November 2022 ruling on inflationary rate increases. In the motion, Cal Water requested inflationary rate increases of 1.5% in Marysville and 4% for all other ratemaking areas besides Selma, Travis Air Force Base, and Visalia for whom a rate increase was not requested. In February of 2023, the ALJ assigned to evaluate the motion granted Cal Water's request. Cal Water is expecting to implement the new rates April 15, 2023 and the new rates are expected to be considered interim rates as of the effective date of the implementation. Escalation Increase Requests As a part of the decision on the 2018 GRC, Cal Water was authorized to request annual escalation rate increases for 2021 and 2022 for those districts that passed the earnings test. In November of 2021, Cal Water requested 2022 escalation rate increases for 19 of its regulated districts. The increase in annual adopted gross revenue associated with the November 2021 filing was $21.7 million. The new rates were implemented on January 1, 2022. Expense Offset Requests Expense offsets are dollar-for-dollar increases in revenue to match increased expenses, and therefore do not affect net operating income. In December of 2021, Cal Water submitted an advice letter to request offsets for increases in purchased water costs and pump taxes in seven of its regulated districts totaling $5.2 million. The new rates were implemented on January 1, 2022. In June of 2022, Cal Water submitted an advice letter to request offsets for increases in purchased water costs and pump taxes in four of its regulated districts totaling $12.7 million. The new rates were implemented on August 1, 2022. In December of 2022, Cal Water submitted an advice letter to request offsets for increases in purchased water costs and pump taxes in five of its regulated districts totaling $5.1 million. The new rates were implemented on January 1, 2023. Rate Base Offset Requests For construction projects authorized in GRCs as advice letter projects, Cal Water is allowed to request rate base offsets to increase revenues after the project goes into service. In November of 2021, Cal Water submitted an advice letter to recover $0.2 million of annual revenue increase for a rate base offset in one of its regulated districts. The new rates were implemented on January 1, 2022. In March of 2022, Cal Water submitted an advice letter to recover $0.1 million of annual revenue increase for a rate base offset in one of its regulated districts. The new rates were implemented on April 15, 2022. WRAM/MCBA Filings In April of 2022, Cal Water submitted an advice letter to true up the revenue under-collections for the 2021 annual WRAMs/MCBAs of its regulated districts. A net under-collection of $54.1 million is being recovered/refunded from/to customers in the form of 12, 18, and greater-than-18-month surcharges and 12 month surcredits. The new rates incorporate net WRAM/MCBA balances that were previously approved for recovery and were implemented on April 15, 2022. Cost of Capital Application On May 3, 2021, after an approved extension from a 2020 due date, Cal Water filed its required application with the CPUC to review its cost of capital for 2022 through 2024. Cal Water currently has an approved return on equity of 9.2%, a cost of debt of 5.51%, and a capital structure of 53.4% equity to 46.6% debt ratio. Cal Water requested a return on equity of 10.35%, a cost of debt of 4.23%, and a capital structure of 53.4% equity to 46.6% debt ratio. The California Public Advocates Office recommended a return on equity of 7.81%, a cost of debt of 4.23%, and a capital structure of 49.4% equity to 50.6% debt ratio. Evidentiary hearings were held in May 2022 and the case was submitted to the CPUC at the end of the second quarter of 2022. We believe the CPUC will evaluate the proposal along with proposals of other parties, and, in accordance with its standard process, is currently expected to issue a decision no earlier than the second quarter of 2023. In the event that the CPUC adopts the cost of capital components retroactively to January 1, 2022, we estimate the reduced cost of debt, if adopted at our proposed equity capital structure, would reduce annual revenue by approximately $11.0 million. We have not reserved for any potential outcome of the proceeding as we have determined that it is not probable that the proceeding will be approved retroactively to January 1, 2022. California Drought Memorandum Account (DRMA) In June of 2021, Cal Water submitted advice letters to request a DRMA to track, for potential future recovery, the incremental operational and administrative costs incurred to further implement updated Rule 14.1 for voluntary conservation measures and Schedule 14.1 for implementation of our Water Shortage Contingency Plan, which includes activities related to enhanced conservation efforts, staffing, and capital expenditures to ensure a safe, reliable supply of water. The DRMA was approved by the CPUC with an effective date of June 14, 2021. The DRMA also tracks monies paid by customers for fines, penalties, or other compliance measures associated with water use violations; and penalties paid by Cal Water to its water wholesalers. Cal Water has incurred $1.3 million of DRMA related costs in 2022 as compared to $0.6 million in 2021. California's Governor has issued a drought declaration for all California counties through a series of State of Emergency Proclamations with the most recent on March 28, 2022. Given these drought proclamations and current water usage levels in all of its service areas, Cal Water has activated Stage 2 of the Water Use Restrictions of its Water Shortage Contingency Plan (WSCP) of Schedule 14.1 in all of its service areas; as a result, Cal Water has seen increase in DRMA related costs in 2022. In Stage 1, irrigating ornamental landscape with potable water is prohibited during the hours of 8:00 a.m. and 6:00 p.m. For Stage 2, irrigating ornamental landscapes with potable water is limited to no more than three days per week as well as prohibited during the hours of 8:00 a.m. and 6:00 p.m. In addition this stage states that new connections may not install single-pass cooling systems for air conditioning or other cooling system applications unless required for health or safety reasons. Drought Response Memorandum Account (DREMA) In December of 2022, Cal Water received approval for a DREMA to track lost revenues, for potential future recovery, associated with reduced sales as a result of the activation of Rule 14.1 and Schedule 14.1 of its WSCP in all of its service territories. The request is consistent with the CPUC's drought procedures which allow companies without full decoupling mechanisms to track lost revenues, subject to a 20 basis points return on equity adjustment, associated with the reduced sales as a result of the activation of either Rule 14.1 or Schedule 14.1. As Cal Water's full decoupling mechanisms ended on December 31, 2022, the DREMA became effective as of January 1, 2023. Palos Verdes Peninsula Water Reliability Project (Project) In 2002, Cal Water commissioned a Water System Master Plan (Master Plan) for the Palos Verdes water system. The Master Plan identified the high-priority need to augment the existing potable water system with new transmission mains and a new pump station to improve the capacity and reliability of the water system. This resulted in the development of a capital project known as the Project. Before the Project, a single pipeline that is over 60 years old delivered potable water to approximately 90 percent of the Peninsula, and a second pipeline of the same age delivered water to the remaining 10 percent. Both of these pipelines were approaching the end of their useful lives. The CPUC authorized Cal Water to recover revenue associated with costs up to a cap of $96.1 million after the Project is in service, subject to the CPUCs reasonableness review. In 2020, the Project was completed and an Advice Letter 2387 asking for authority to increase rates reflecting the Project costs up to the cap, with an effective date of August 27, 2020 was filed. The advice letter was approved on January 29, 2021. New rates were implemented on February 1, 2021, with the revenue requirement being effective as of August 27, 2020. Due to the complexity of the project, total project costs exceeded the advice letter cap of $96.1 million. Total project costs incurred as of the end of 2022 were $117.2 million. Amongst other things, the 2021 GRC Filing requested an additional $6.4 million of capital costs to be included in base rates plus authority to open a memorandum account allowing Cal Water to track incremental capital-related costs associated with this project. The remaining $14.7 million of capital costs not in base rates will be tracked in the memorandum account for possible future recovery. Regulatory Activity - Other States Kona Water Service Company GRC (Hawaii Water) In May of 2021, Hawaii Water submitted a request for a private letter ruling (PLR) to the IRS on the treatment of deferred taxes because of the Tax Cuts Jobs Act (TCJA). A favorable decision on the PLR was received on November 18, 2021. The Consumer Advocacy, a division within the Department of Commerce and Consumer Affairs of the State of Hawaii that is responsible for matters related to regulated utilities, and Hawaii Water submitted a joint stipulation to the Hawaii Public Utility Commission (HPUC) incorporating the PLR into revised water rates on March 2, 2022. Hawaii Water received approval on December 15, 2022 from the HPUC. HOH Utilities Company (Hawaii Water) In June of 2021, Hawaii Water signed an agreement to acquire the assets of HOH Utilities Company, a wastewater utility located in the growing Poipu/Koloa area of Kauai County on the island of Kauai. Hawaii Water will own and manage the wastewater utility, which currently serves almost 1,800 residential, commercial, and resort customer equivalent units in Poipu and Koloa, including three hotels, condominiums, multi-family housing, a golf course, and single-family homes. Hawaii Water received HPUC approval for the acquisition in June of 2022 and is expecting the acquisition to close by the second quarter of 2023. The acquisition is subject to satisfaction of customary closing conditions. Keauhou Community Services, Inc. (Hawaii Water) In December 2020, Hawaii Water entered into an asset purchase agreement with Keauhou Community Services, Inc. (KCSI). KCSI is a utility that provides wastewater service in the Keauhou area of North Kona on the island of Hawaii. An application for approval of the transaction was submitted to the HPUC in October of 2021 and was approved in December of 2022. Accordingly, the transaction closed and Hawaii Water took control over the system on December 15, 2022. Hawaii Water has operated the system under an operations and maintenance agreement since 2018. Hawaii Water now owns and operates the utility, which consists of residential, commercial, and resort customers. Kalaeloa Water Company GRC (Hawaii Water) In August of 2021, a GRC application requesting an increase of revenues for Kalaeloa was submitted with the HPUC. In June of 2022, Hawaii Water and the Consumer Advocacy submitted a full settlement agreement to the HPUC for approval. The HPUC issued a decision approving the settlement agreement in September of 2022. The approval increased authorized revenue for Kalaeloa by $0.15 million or 4.9%. 2021 Washington Water GRC (Washington Water) On July 15, 2021, Washington Water filed a GRC application with the Washington Utilities and Transportation Commission (WUTC) requesting a phased-in consolidation of its East Pierce Water System with its legacy Washington Water system. The requested annual revenue increase was $3.1 million and was proposed to be implemented over 3 years. After working with the WUTC and Public Counsel, a unit of the Washington Attorney General's Office that represents customers of state-regulated, investor-owned utility companies in certain matters, Washington Water updated its application on February 2, 2022 with a revised annual revenue increase of $1.0 million and eliminated the 3-year rate increase proposal. The WUTC approved the GRC application on February 10, 2022 with an effective date of February 15, 2022. Animas Valley Land and Water Co., LLC (New Mexico Water) In October of 2020, New Mexico Water signed a purchase agreement with Animas Valley Land and Water Co., LLC (AV Water) and court-appointed receiver C. Randel Lewis to acquire the Morning Star Water System assets of AV Water and provide regulated water utility service to its approximately 2,000 customer connections in northwest New Mexico. In April of 2022, New Mexico Water closed its purchase of the Morningstar Water system. In February of 2022, the NMPRC approved of the transaction. New Mexico water closed the purchase and commenced operation of the water system as of April 14, 2022. Lake Section Water Company (New Mexico Water) In January of 2023, New Mexico Water signed an agreement to purchase the assets of Lake Section Water Company (Lake Section), a utility located in Chapparal, N.M. The acquisition is subject to satisfaction of customary closing conditions and approval by the NMPRC. As part of the purchase, New Mexico Water has agreed to own and operate the Lake Section water system, which serves approximately 5,000 customer connections about 110 miles south of New Mexico Waters Elephant Butte system in the greater El Paso, Texas, metropolitan area. Water Supply Our source of supply varies among our operating districts. Certain districts obtain all of their supply from wells; some districts purchase all of their supply from wholesale suppliers; and other districts obtain supply from a combination of wells and wholesale suppliers. A small portion of supply comes from surface sources and is processed through Company-owned water treatment plants. To the best of management's knowledge, we are meeting water quality, environmental, and other regulatory standards for all Company-owned systems. Historically, approximately half of our annual water supply is pumped from wells. State groundwater management agencies operate differently in each state. Some of our wells extract ground water from water basins under state ordinances. These are adjudicated groundwater basins, in which a court has settled the dispute between landowners, or other parties over how much annual groundwater can be extracted by each party. All of our adjudicated groundwater basins are located in the State of California. Our annual groundwater extraction from adjudicated groundwater basins approximates 5.7 billion gallons or 10.8% of our total annual water supply pumped from wells. Historically, we have extracted less than 100% of our annual adjudicated groundwater rights and have the right to carry forward up to 20% of the unused amount to the next annual period. All of our remaining wells extract ground water from managed or unmanaged water basins. There are no set limits for the ground water extracted from these water basins. Our annual groundwater extraction from managed groundwater basins approximates 31.5 billion gallons or 59.9% of our total annual water supply pumped from wells. Our annual groundwater extraction from unmanaged groundwater basins approximates 15.4 billion gallons or 29.3% of our total annual water supply pumped from wells. Most of the managed groundwater basins we extract water from have groundwater recharge facilities. We are required to financially support these groundwater recharge facilities by paying well pump taxes. Our well pump taxes for 2022, 2021, and 2020 were $16.2 million, $15.3 million, and $12.6 million, respectively. In 2014, the State of California enacted the Sustainable Groundwater Management Act of 2014 (SGM Act). The law and its implementing regulations required most basins to select a sustainability agency by 2017, develop a sustainability plan by the end of 2022, and show progress toward sustainability by 2027. We expect that after the SGM Act's provisions are fully implemented, substantially all the Company's California groundwater will be produced from sustainably managed and adjudicated basins. California's normal weather pattern yields little precipitation between mid-spring and mid-fall. The Washington Water service areas receive precipitation in all seasons, with the heaviest amounts during the winter. New Mexico Water's rainfall is heaviest in the summer monsoon season. Hawaii Water receives precipitation throughout the year, with the largest amounts in the winter months. Typically water usage in all service areas is highest during the warm and dry summers and declines in the cool winter months. Rain and snow during the winter months in California replenish underground water aquifers and fill reservoirs, providing the water supply for subsequent delivery to customers. As of February 10, 2023, the State of California snowpack water content during the 2022-2023 water year was 165% of long-term averages (per the California Department of Water Resources, Northern Sierra Precipitation Accumulation report). The northern Sierra region is the most important for the states urban water supplies. The central and southern portions of the Sierras have recorded 197% and 230%, respectively, of long-term averages. Management believes that supply pumped from underground aquifers and purchased from wholesale suppliers will be adequate to meet customer demand during 2023 and thereafter. Long-term water supply plans are developed for each of our districts to help assure an adequate water supply under various operating and supply conditions. Some districts have unique challenges in meeting water quality standards, but management believes that supplies will meet current standards using currently available treatment processes. On May 31, 2018, California's Governor signed two bills (Assembly Bill 1668 and Senate Bill 606) into law that were intended to establish long-term standards for water use efficiency. The bills revise and expand the existing urban water management plan requirements to include five-year drought risk assessments, water shortage contingency plans, and annual water supply/demand assessments. The California State Water Resources Control Board, in conjunction with the California Department of Water Resources, is expected to establish long-term water use standards for indoor residential use, outdoor residential use, water losses, and other uses. Cal Water will also be required to calculate and report on urban water use target by November 1, 2023 and each November 1 thereafter, that compares actual urban water use to the target. Management believes that Cal Water is well positioned to comply with all such regulations. The following table shows the estimated quantity of water purchased and the percentage of purchased water to total water production in each California operating district that purchased water in 2022. Other than noted below, all other districts receive 100% of their water supply from wells. ##TABLE_START District Water Purchased (MG) Percentage of Total Water Production Source of Purchased Supply SAN FRANCISCO BAY AREA/NORTH COAST Bay Area Region* 6,539 99.5 % San Francisco Public Utilities Commission and Yolo County Flood Control Water Conservation District Bear Gulch 3,711 97.7 % San Francisco Public Utilities Commission Los Altos 2,103 60.0 % Santa Clara Valley Water District Livermore 2,058

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74.8 % Alameda County Flood Control and Water Conservation District, Zone 7 SACRAMENTO VALLEY Oroville 765 95.9 % Pacific Gas and Electric Co. and County of Butte SAN JOAQUIN VALLEY Bakersfield 8,784 46.8 % Kern County Water Agency and City of Bakersfield Stockton 6,793 89.1 % Stockton East Water District LOS ANGELES AREA East Los Angeles 948 21.3 % Central Basin Municipal Water District Dominguez 9,163 88.8 % West Basin Municipal Water District and City of Torrance City of Commerce 601 78.3 % Central Basin Municipal Water District City of Hawthorne 1,122 92.0 % West Basin Municipal Water District Hermosa Redondo 3,091 91.1 % West Basin Municipal Water District Los Angeles County Region** 5,274 97.3 % West Basin Municipal Water District and Antelope Valley-East Kern Water Agency Westlake 1,949 100.0 % Calleguas Municipal Water District and Triunfo Water and Sanitation District Kern River Valley 61 25.2 % City of Bakersfield
##TABLE_END____

MG = million gallons * Bay Area Region includes Bayshore and Redwood Valley ** Los Angeles County Region includes Palos Verdes and Antelope Valley The Bear Gulch district obtains a portion of its water supply from surface runoff from the local watershed. The Oroville district in the Sacramento Valley, the Bakersfield district in the San Joaquin Valley, and the Kern River Valley district in the Los Angeles Area purchase water from a surface supply. Surface sources are processed through our water treatment plants before being delivered to the distribution system. The Bakersfield district also purchases treated water as a component of its water supply. The Chico, Marysville, Dixon, and Willows districts in the Sacramento Valley, the Salinas Valley Region district in the Salinas Valley, the Selma and Visalia districts in the San Joaquin Valley, and the Travis Air Force Base in Solano County obtain their entire supply from wells. Purchases for the Los Altos, Livermore, Oroville, Redwood Valley, Stockton, and Bakersfield districts are pursuant to long-term contracts expiring on various dates after 2022. The water supplies purchased for the Dominguez, East Los Angeles, Hermosa Redondo, Palos Verdes, and Westlake districts as well as the Hawthorne and Commerce systems are provided by public agencies pursuant to a statutory obligation of continued non-preferential service to purveyors within the agencies' boundaries. Purchases for the Bayshore and Bear Gulch districts are in accordance with long-term contracts with the San Francisco Public Utilities Commission (SFPUC) until June 30, 2034. Management anticipates water supply contracts will be renewed as they expire though the price of wholesale water purchases is anticipated to increase in the future. Shown below are wholesaler price rates and increases that became effective in 2022, and estimated wholesaler price rates and percent changes for 2023. In 2022, several districts experienced purchased water rate increases, resulting in the filing of several purchased water offsets.
##TABLE_START 2022 2023 District Effective Month Unit Cost Percent Change Effective Month Unit Cost Percent Change Antelope January $699.00 /af 5.1% January $699.00 /af Bakersfield (1) July $179.00 /af July $179.00 /af Bear Gulch July $4.75 /ccf 15.9% July $4.75 /ccf Commerce (2) July $1,313.00 /af 0.8% January $1,379.00 /af 5.0% Dominguez (2) July $1,500.00 /af 3.5% January $1,587.00 /af 5.8% East Los

Angeles (2) July $1,313.00 /af 0.8% January $1,379.00 /af 5.0% Hawthorne (2) July $1,500.00 /af 3.5% January $1,587.00 /af 5.8% Hermosa-Redondo (2) July $1,500.00 /af 3.5% January $1,587.00 /af 5.8% Livermore January $2.06 /ccf (1.9)% January $2.27 /ccf 10.2% Los Altos July $1,839.00 /af 13.9% July $1,839.00 /af Oroville (2) April $200,052 /yr 6.2% April $203,769 /yr 1.9% Palos Verdes (2) July $1,500.00 /af 3.5% January $1,587.00 /af 5.8% Mid-Peninsula July $4.75 /ccf 15.9% July $4.75 /ccf Redwood Valley April $69.24 /af April $69.24 /af South San Francisco July $4.75 /ccf 15.9% July $4.75 /ccf Stockton April $918,145 /mo (36.8)% April $918,145 /mo Westlake January $1,561.00 /af 3.6% January $1,632.00 /af 4.5%
##TABLE_END____
af = acre foot; ccf = hundred cubic feet; yr = fixed annual cost; mo = fixed monthly cost (1) untreated water (2) wholesaler price changes occur every six months We work with all local suppliers and agencies responsible for water supply to enable adequate, long-term supply for each system. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of OperationsWater Supply" for more information on adequacy of supplies. Seasonal Fluctuations In California, our customers' consumption pattern of water varies with the weather, in terms of rainfall and temperature. When setting customer rates, the CPUC considers the historical pattern in determining the adopted sales and production costs. With a majority of our sales expected to be subject to the MWRAM and per-unit variations in production costs being covered by the ICBA, fluctuations in financial results are expected to be moderated once the MWRAM and ICBA mechanisms are approved by the CPUC. However, cash flows from operations and short-term borrowings on our credit facilities can be significantly impacted by seasonal fluctuations including recovery of the MWRAM and ICBA. Our water business is seasonal in nature. Weather conditions can have a material effect on customer usage. Customer demand for water generally is lower during the cooler and rainy winter months. Demand increases in the spring when warmer weather returns and the rains end, and customers use more water for outdoor purposes such as landscape irrigation. Warm temperatures during the generally dry summer months result in increased demand. Water usage declines during the late fall as temperatures decrease and the rainy season begins. During years in which precipitation is especially heavy or extends beyond the spring into the early summer, customer demand can decrease from historic normal levels, generally due to reduced outdoor water usage. Likewise, an early start to the rainy season during the fall can cause a decline in customer usage. As a result, seasonality of water usage has a significant impact on our cash flows from operations and borrowing on our short-term facilities. Utility Plant Construction We have continually extended, enlarged, and replaced our facilities as required to meet increasing demands and to maintain the water systems. We obtain construction financing using funds from operations, long-term financing, advances for construction and contributions in aid of construction that are funded by developers. Advances for construction are cash deposits from developers for construction of water facilities or water facilities deeded from developers. These advances are generally refundable without interest over a

period of 40 years in equal annual payment amounts and developer-installed facilities are exempt from corporate income taxes. Contributions in aid of construction consist of nonrefundable cash deposits or facilities transferred from developers, primarily for fire protection and relocation projects. We cannot control the amounts received from developers. This amount fluctuates from year-to-year as the level of construction activity carried on by developers varies. This activity is impacted by the demand for housing, commercial development, and general business conditions, including interest rates. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of OperationsLiquidity and Capital Resources" for additional information. Energy Reliability We continue to seek to use power efficiently to minimize the power expenses passed on to our customers, and maintain backup power systems to continue water service to our customers if the power companies' supplies are interrupted. If future legislation limits emissions from the power generation process, our cost of power may increase. Any increase in the per-unit cost of power would be expected to be passed along to our California customers through the ICBA or included in our cost of service paid by our customers as requested in our GRC filings. Many of our well sites are equipped with emergency electric generators designed to produce electricity to keep the wells operating during power outages. Storage tanks also provide customers with water during blackout periods. During 2022, 2021, and 2020 we leased additional emergency generators to respond to potential PSPSs, an electric utility operating paradigm approved by the CPUC. Security at Company Facilities Due to terrorism and other risks, we have heightened security at our facilities and have taken added precautions to protect our employees and the water delivered to customers. In 2002, federal legislation was enacted that resulted in new regulations concerning security of water facilities, including submitting vulnerability assessment studies to the federal government. We have complied with regulations issued by the U.S. Environmental Protection Agency (EPA) pursuant to federal legislation concerning vulnerability assessments and have made filings to the EPA as required. In addition, communication plans have been developed as a component of our procedures. While we do not make public comments on our security programs, we have been in contact with federal, state, and local law enforcement agencies to coordinate and improve our water delivery systems' security. In accordance with the 2018 Americas Water Infrastructure Act (AWIA), we are required to conduct additional risk and resilience assessments and develop emergency response plans for each of our water systems. These assessments and plans include natural hazards as well as malevolent acts. The first such assessments were filed in 2020. They are scheduled to be reviewed and resubmitted every five years. While we do not make public comments on our security programs, we have been in contact with federal, state, and local law enforcement agencies to coordinate and improve our water delivery systems' security Competition and Condemnation Our principal operations are regulated by the Commission of each state. Under state laws, no privately owned public utility may compete within any service territory that we already serve without first obtaining a certificate of public convenience and necessity from the applicable Commission.

Issuance of such a certificate would only be made upon finding that our service is deficient. To management's knowledge, no application to provide service to an area served by us has been made. State law in California provides that whenever a public agency constructs facilities to extend a utility system into the service area of a privately owned public utility, such an act constitutes the taking of property and requires reimbursement to the utility for its loss. State law in Washington and other states recognize chartered service areas but do not have specific statutes. State statutes allow municipalities, water districts and other public agencies to own and operate water systems. These agencies are empowered to condemn properties already operated by privately owned public utilities. The agencies are also authorized to issue bonds, including revenue bonds, for the purpose of acquiring or constructing water systems. However, if a public agency were to acquire utility property by eminent domain action, the utility would be entitled to just compensation for its loss. In Washington, annexation was approved in February 2008 for property served by us on Orcas Island; however, we continue to serve the customers in the annexed area and do not expect the annexation to affect our operations. To management's knowledge, other than the Orcas Island property, no municipality, water district, or other public agency is contemplating or has any action pending to acquire or condemn any of our systems. Government Regulations Our water and wastewater services are governed by various federal and state environmental protection, health and safety laws, and regulations. These provisions establish criteria for drinking water and for discharges of water, wastewater, and airborne substances. The EPA, state water quality regulators, and other state regulatory authorities promulgate numerous nationally and locally applicable standards, including maximum contaminant levels (MCLs) for drinking water. We believe we are currently in compliance with all of the MCLs promulgated to date. Environmental Matters Our operations are subject to environmental regulation by various governmental authorities. Environmental health and safety programs have been designed to provide compliance with water discharge regulations, underground and above-ground fuel storage tank regulations, hazardous materials management plans, hazardous waste regulations, air quality permitting requirements, wastewater discharge limitations, and employee safety issues related to hazardous materials. In addition, we actively investigate alternative technologies for meeting environmental regulations and continue the traditional practices of meeting environmental regulations. For a description of the material effects that compliance with environmental regulations may have on us, see Item 1A. "Risk FactorsRisks Related to Our Regulatory Environment." We expect environmental regulation to increase, resulting in higher operating costs in the future, and there can be no assurance that the Commissions would approve rate increases to enable us to recover these additional compliance costs. Quality of Water Supply Our operating practices are designed to produce potable water in accordance with accepted water utility practices. Water entering the distribution systems from surface sources is treated in compliance with federal and state Safe Drinking Water Act (SDWA) standards. Most well supplies are chlorinated or chloraminated for disinfection. Water samples from each water system are analyzed on a regular, scheduled basis in compliance with regulatory requirements. We operate a state-certified water quality laboratory at the San Jose Customer Support Services Office that provides testing for most of our California operations. Certain tests in California are contracted with independent certified labs qualified under the Environmental Laboratory Accreditation Program. Local independent state certified labs provide water sample testing for the Washington, New Mexico and Hawaii operations. In recent years, federal and state water quality regulations have resulted in increased water sampling requirements. The SDWA continues to be used to monitor and regulate additional potential contaminants to address public health concerns. The State of California has continued to adopt new water quality regulations, which may be in addition to those adopted by the EPA. We monitor water quality standard changes and upgrade our treatment capabilities to maintain compliance with the various regulations. Impact of Climate Change Legislation and Regulation Our operations depend on power provided by other public utilities and, in emergencies, power generated by our portable and fixed generators. If future legislation limits emissions from the power generation process, our cost of power may increase. Any increase in the cost of power would be expected to be passed along to our California customers through the ICBA or included in our cost of service paid by our customers as requested in our GRC filings. We maintain a fleet of vehicles to provide service to our customers, including a number of heavy-duty diesel vehicles that were retrofitted to meet California emission standards. If future legislation further affects the cost to operate the fleet or the fleet acquisition cost in order to meet certain emission standards, it would increase our cost of service and our rate base. Any increase in fleet operating costs associated with meeting emission standards would be expected to be included in our cost of service paid by our customers as requested in our GRC filings. While recovery of these costs is not guaranteed, we would expect recovery in the regulatory process. Under the California Environmental Quality Act (CEQA), all capital projects of a certain type (primarily wells, tanks, major pipelines, and treatment facilities) require mitigation of greenhouse gas emissions. The cost to prepare the CEQA documentation and permit are expected to be included in our capital cost and added to our rate base, which is expected to be requested to be paid for by our customers. Any increase in the operating cost of the facilities would also be expected to be included in our cost of service paid by our customers as requested in our GRC filings. While recovery of these costs is not guaranteed, we would expect recovery in the regulatory process. Cap and trade regulations were implemented in 2012 with the goal of reducing emissions to 1990 levels by the year 2020. These regulations have not affected water utilities at this time. In the future, if we are required to comply with these regulations, any increase in operating costs associated with meeting these standards will be included in our cost of service paid by our customers as requested in our GRC filings. While recovery of these costs is not guaranteed, we would expect recovery in the regulatory process. Human Capital Resources We believe our employees are our most important resources and are critical to our continued success. We focus significant attention on attracting and retaining talented and experienced individuals to manage and support our operations. We offer our employees a broad range of company-paid benefits, and we believe our compensation package and benefits are competitive with others in our industry. Additional information about our employee benefit plans is included in Note 11 of the Notes to Consolidated Financial Statements. We are committed to hiring, developing and supporting a diverse and inclusive workplace. Our employees are expected to exhibit and promote honest, ethical, and respectful conduct in the workplace. All of our employees must adhere to a code of conduct that sets standards for appropriate behavior and includes required internal training on preventing, identifying, reporting and stopping any type of discrimination. Employee health and safety in the workplace is one of the Companys core values. Safety efforts are led by the Corporate Safety Committee and supported by safety committees that operate at the local level. Hazards in the workplace are actively identified and management tracks incidents so remedial actions can be taken to improve workplace safety. The COVID-19 pandemic has underscored for us the importance of keeping our employees safe and healthy. In response to the pandemic, the Company has taken actions aligned with the World Health Organization and the Centers for Disease Control and Prevention to protect its workforce so they can more safely and effectively perform their work. Our management team supports a culture of developing future leaders from our existing workforce, enabling us to promote from within for many leadership positions. We believe this provides long-term focus and continuity to our operations while also providing opportunities for the growth and advancement of our employees. Our focus on retention is evident in the length of service of our management team. The average tenure of our management team is over 15 years. Employee levels are managed to align with the pace of business and management believes it has sufficient human capital to operate its business successfully. Management believes that the Company's employee relations are favorable. At December 31, 2022, we had 1,225 employees, including 1,077 at Cal Water, 80 at Washington Water, 49 at Hawaii Water, 19 at New Mexico Water, and no employees at Texas Water. In California, the Utility Workers Union of America (UWUA), AFL-CIO represents our non-exempt field, customer service, and non-confidential clerical employees and the International Federation of Professional and Technical Engineers (IFPTE), AFL-CIO represents our professional and technical engineering and water quality laboratory employees. As of December 31, 2022, we had 659 employees represented by the UWUA and 85 employees represented by the IFPTE. In 2021, we reached a six-year agreement with both unions on a new contract that runs from May 14, 2021 (UWUA) and October 4, 2021 (IFPTE) through February 28, 2027. We believe this agreement continues to provide our employees with a market competitive pay and benefits package. Employees at Hawaii Water, Washington Water, and New Mexico Water are not represented by a labor union. Information About Our Executive Officers ##TABLE_START Name Positions and Offices with California Water Service Group Age Martin A. Kropelnicki (1) President and Chief Executive Officer since September 1, 2013. Formerly, President and Chief Operating Officer (2012-2013), Chief Financial

Officer and Treasurer (2006-2012), served as Chief Financial Officer of Power Light Corporation (2005-2006), Chief Financial Officer and Executive Vice President of Corporate Services of Hall Kinion and Associates (1997-2004), Deloitte Touche Consulting (1996-1997), held various positions with Pacific Gas Electric (1989-1996). 56 Thomas F. Smegal III (2) Vice President, Chief Financial Officer and Treasurer since October 1, 2012. Formerly, Vice President, Regulatory Matters and Corporate Relations (2008-2012), Manager of Rates (2002-2008), Regulatory Analyst (1997-2002), served as Utilities Engineer at the California Public Utilities Commission (1990-1997). 55 Paul G. Townsley (2)(3) Vice President, Corporate Development since January 1, 2022. Formerly, Vice President of Corporate Development and Chief Regulatory Matters Officer (2019-2021), Vice President of Rates and Regulatory Matters (2013-2018), Divisional Vice President, Operations and Engineering for EPCOR Water USA (2012-2013), served as President of American Water Works Company subsidiaries in Arizona, New Mexico, and Hawaii (2007-2012), served as American Water Works Company's President, Western Region (2002-2007), held various other positions with Citizens Utilities Company (1982-2002). 65 Robert J. Kuta (2) Vice President, Engineering and Chief Water Quality and Environmental Compliance Officer effective January 1, 2019. Formerly, Vice President of Engineering (2015-2018), Senior Vice President of Operations Management Services, Water, Environmental and Nuclear markets for CH2M Hill (2006 to 2015), served as Western Region Vice President of Service Delivery and President of Arizona American Water Company (2001 to 2005), and held various management positions at Citizens Water Resource Company, Chaparral City Water Company, and Spring Creek Utilities (1993 to 2001). 58 Michael B. Luu (2) Vice President, Information Technology and Chief Risk Officer since January 1, 2021. Formerly Vice President of Customer Service and Chief Information Officer (2017-2020), Vice President of Customer Service and Information Technology (2013-2016), Acting California Water Service Company District Manager, Los Altos (2012-2013), Director of Information Technology (2008-2012), CIS Development Manager (2005-2008), held various other positions with California Water Service Company since 1999. 43 Ronald D. Webb (2) Vice President, Chief Human Resource Officer since January 1, 2022. Formerly, Vice President of Human Resources (2014-2021), Managing Director, Human Resources Partner for United Airlines (2006-2014), served as Vice President of Human Resources for Black Decker Corporation (1995-2005), Human Resource Manager for General Electric Company (1990-1994), and held various labor relations positions for National Steel and Shipbuilding Company (1982-1989). 66 Lynne P. McGhee (2)(4) Vice President, General Counsel since January 1, 2015. Formerly, Corporate Secretary (2007-2014), Associate Corporate Counsel (2003-2014), and served as a Commissioner legal advisor and staff counsel at the California Public Utilities Commission (1998-2003). 58 ##TABLE_END##TABLE_START Name Positions and Offices with California Water Service Group Age Shannon C. Dean (2) Vice President, Customer Service and Chief Citizenship Officer since January 1, 2021. Formerly, Vice President of Corporate

Communications Community Affairs (2015-2020), Director of Corporate Communications (2000-2014), held various corporate communications, government and community relations for Dominguez Water Company (1991-1999). 55 Michelle R. Mortensen (2) Vice President, Corporate Secretary and Chief of Staff since January 1, 2022. Formerly, Vice President, Corporate Secretary (2021), Corporate Secretary (2015-2020), Assistant Corporate Secretary (2014), Treasury Manager (2012-2013), Assistant to the Chief Financial Officer (2011), Regulatory Accounting Manager (2008-2010), held various accounting positions at Piller Data Systems (2006-2007), Hitachi Global Storage (2005), Abbot Laboratories (1998-2004), and Symantec (1998-2001). 48 Elissa Y. Ouyang (2) Vice President, Facilities, Fleet and Procurement since January 1, 2022. Formerly, Chief Procurement and Lead Continuous Improvement Officer (2016-2021), Interim Procurement Director (2013-2016), Acting District Manager - Los Altos (2013), Interim Vice President of Information Technology (2012-2013), Director of Information Technology - Architecture and Security (2008-2012), Business Application Manager (2003-2007), Project Lead/Senior Developer (2001-2003), held various business consulting positions at KPMG Consulting/BearingPoint (1998-2001), and RR Donnelley (1996-1998). 54 Michael S. Mares, Jr (2) Vice President, Operations since January 1, 2021. Formerly, Vice President, California Operations (2019-2020), California Water Service Company District Manager, Bakersfield (2017-2018), Hawaii Water Service Company General Manager (2014-2016), Hawaii Water Service Company Local Manager, Big Island (2012-2014), California Water Service Company, held various Superintendent positions in the Chico district (2002-2012), California Water Service Company, held various union positions in the Chico district (1992-2002). 56 Greg A. Milleman (2) Vice President, Rates Regulatory Affairs since January 1, 2022. Formerly, Vice President, California Rates (2019-2021), Interim Director of Rates (2017-2018), Director of Field Administration Finance (2014-2017), Manager of Special Projects (2013), and served as Senior Vice President of Administration and Corporate Secretary and various other management positions for Valencia Water Company (1992-2013). 60 Thomas A. Scanlon (2) Corporate Controller and Principal Accounting Officer since January 1, 2023. Formerly, Director of Financial Reporting (2010-2022), Subsidiary Controller at Sun Power Systems Corporation (2007-2010), and Regional Controller at Swinerton Builders, Inc. (2000-2007). 60
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(1) Holds the same position with California Water Service Company, CWS Utility Services, Hawaii Water Service Company, Inc., New Mexico Water Service Company and TWSC, Inc.; Chief Executive Officer of Washington Water Service Company. (2) Holds the same position with California Water Service Company, CWS Utility Services, Hawaii Water Service Company, Inc., New Mexico Water Service Company, Washington Water Service Company, and TWSC, Inc. (3) Scheduled to retire on May 1, 2023. (4) Scheduled to retire on March 31, 2023. Item 1A. Risk Factors. In evaluating our business, you should carefully consider the following discussion of material risks,

events and uncertainties that make an investment in us speculative or risky in addition to the other information in this Annual Report on Form 10-K. A manifestation of any of the following risks and uncertainties could, in circumstances we may or may not be able to accurately predict, materially and adversely affect our business, growth, reputation, prospects, operating and financial results, financial condition, cash flows, liquidity, and stock price. We note these factors for investors as permitted by the Private Securities Litigation Reform Act of 1995. It is not possible to predict or identify all such factors; our operations could also be affected by factors, events or uncertainties that are not presently known to us or that we currently do not consider to present significant risks to our operations. Therefore, you should not consider the following risks to be a complete statement of all the potential risks or uncertainties that we face. Risks Related to Our Regulatory Environment Our business is heavily regulated by state and federal regulatory agencies and our financial viability depends upon our ability to recover costs from our customers through rates that must be approved by state public utility commissions. California Water Service Company, New Mexico Water Service Company, Washington Water Service Company, and Hawaii Water Service Company, Inc. are regulated public utilities, which provide water and water-related service to our customers. Additionally, Hawaii Water Service Company, Inc. and TWSC, Inc. own in whole or in part other companies which are regulated public utilities. The rates that we charge our water customers are subject to the jurisdiction of the regulatory Commissions in the states in which we operate. These Commissions may set water and water-related rates for each operating district independently because the systems are not interconnected. The Commissions authorize us to charge rates that they consider sufficient to recover normal operating expenses, to provide funds for adding new or replacing water infrastructure, and to allow us to earn what the Commissions consider to be a fair and reasonable return on invested capital. Our revenues and consequently our ability to meet our financial objectives are dependent upon the rates we are authorized to charge our customers by the Commissions and our ability to recover our costs in these rates. Our management uses forecasts, models and estimates in order to set rates that we believe will provide a fair and reasonable return on our invested capital. While our rates must be approved by the Commissions, no assurance can be given that our forecasts, models and estimates will be correct or that the Commissions will agree with our forecasts, models and estimates. If our rates are set too low, our revenues may be insufficient to cover our operating expenses, capital expenditure requirements and desired dividend levels. We periodically file rate increase applications with the Commissions. The ensuing administrative and hearing process may be lengthy and costly. The decisions of the Commissions are beyond our control and we can provide no assurances that our rate increase requests will be granted by the Commissions. Even if approved, there is no guarantee that approval will be given in a timely manner or at a sufficient level to cover our expenses and provide a reasonable return on our investment. If the rate increase decisions are delayed, our earnings may be adversely affected. For example, the CPUC did not issue its decision on our 2018

GRC until December 2020, approximately one year later than expected, which caused some financial and operating uncertainty for the Company until that time. Our evaluation of the probability of recovery of regulatory assets is subject to adjustment by regulatory agencies and any such adjustment could adversely affect our results of operations and financial condition. Regulatory decisions may affect prospective revenues and earnings, affect the timing of the recognition of revenues and expenses and may overturn past decisions used in determining our revenues and expenses. While, our management continually evaluates the anticipated recovery of regulatory assets and revenues subject to refund and provides for allowances and/or reserves as deemed necessary, no assurance can be given that any such allowances and/or reserves will be adequate to cover any loss or adjustment due to the absence of our limited recovery of regulatory assets and revenues as a result of regulatory decisions. Current accounting procedures allow us to defer certain costs if we believe it is probable that we will be allowed to recover those costs through future rate increases. If the Commissions determined that a portion of our assets were not recoverable in customer rates, we may suffer an asset impairment, which would require a write down in such asset's valuation that would be recorded through operations. If our assessment as to the probability of recovery through the ratemaking process is later determined to be incorrect, the associated regulatory asset would be adjusted to reflect the change in our assessment or any regulatory disallowances. A change in our evaluation of the probability of recovery of regulatory assets or a regulatory disallowance of all or a portion of our cost could have a material adverse effect on our financial results. Regulatory agencies may disagree with our valuation and characterization of certain of our assets. If we determine that assets are no longer used or useful for utility operations, we may remove them from our rate base and subsequently sell those assets with any gain on sales accruing to the stockholders, subject to certain conditions. If the Commissions disagree with our characterization, there is a risk that the Commissions could determine that realized appreciation in property value should be awarded to customers rather than our stockholders. Changes in laws, rules, and policies of our regulators or operating jurisdictions can significantly affect our business. Regulatory agencies may change their rules and policies for various reasons, including changes in the local political environment. Regulators are elected by popular vote or are appointed by elected officials, and the election of a new administration or the appointment of new officials due to the results of elections may result in dramatic change to the long-established rules and policies of an agency. For example, in 2020 regulation regarding full decoupling WRAMs changed in California. Since 2008, the CPUC allowed full decoupling WRAMs. However, in 2020, the CPUC precluded companies from proposing full decoupling WRAMs in their next GRC filings. The decision by the CPUC to change its policy began to affect our business in 2023. We rely on policies and regulations promulgated by the various state commissions in order to recover capital expenditures, maintain favorable treatment on gains from the sale of real property, offset certain production and operating costs, recover the cost of debt, maintain an optimal equity structure without over-leveraging, and have financial and operational flexibility to engage in non-regulated operations. If any of the Commissions with jurisdiction over us implements policies and regulations that do not allow us to accomplish some or all of the items listed above, our future operating results may be adversely affected. In addition, legislatures may repeal, relax or tighten existing laws, or enact new laws that affect the regulatory agencies with jurisdiction over our business or affect our business directly. If changes in existing laws or the implementation of new laws limit our ability to accomplish some of our business objectives, our future operating results may be adversely affected. Finally, local jurisdictions may impose new ordinances, laws, fees, and regulations that could increase costs or limit our operations in ways, which affect future operating results. Cities may impose or amend franchise requirements, impose conditions on underground construction or land use, impose various taxes and fees, or restrict our hours for construction, among other things. In the last decade, more cities have imposed excavation moratoria or paving rules, which has required more costly construction than anticipated. We expect environmental health and safety regulation to increase, resulting in higher operating costs in the future and the potential that the company fails to meet these regulatory standards. Our water and wastewater services are governed by various federal and state environmental protection, health and safety laws, and regulations. Although we have a water quality assurance program in place, we cannot guarantee that we will continue to comply with all standards. If we violate any federal or state regulations or laws governing health and safety, we could be subject to substantial fines or otherwise sanctioned, subject to potential civil liability for damages, and our customers' trust in our operations ability could be eroded. Environmental health and safety laws are complex and change frequently. They have tended to become more stringent over time. As new or stricter standards are introduced, they could increase our operating costs. Although we would likely seek permission to recover these costs through rate increases, we can give no assurance that the Commissions would approve rate increases to enable us to recover these additional compliance costs. We are required to test our water quality for certain chemicals and potential contaminants on a regular basis. If the test results indicate that our water exceeds allowable limits, we may be required either to commence treatment to remove the contaminant or to develop an alternate water source. Either of these results may be costly. Although we would likely seek permission to recover these through rate increases, there can be no assurance that the Commissions would approve rate increases to enable us to recover these additional compliance costs. Past events in the utility sector, including those in Flint, Michigan and related to Pacific Gas and Electric Company in California, show that failure to meet one or more water quality, environmental, or safety standards can have severe effects on customer trust, reputation, regulatory treatment, or civil and criminal liability. New and/or more stringent water quality regulations could increase our operating costs. We are subject to water quality standards set by federal, state, and local authorities that have the power to issue new regulations. Compliance with new regulations that are more stringent than current regulations could increase our operating costs. In August of 2009, the Office of Environmental Health Hazard Assessment within the California Environmental Protection Agency changed the water quality standard for TCP in our water supply. The standard implemented requires us to have 0.0007 parts per billion or less of TCP in our California water supply. We have incurred costs associated with the compliance of this TCP standard and expect to continue to incur costs in the future. Although we would likely seek permission to recover these additional costs through the GRC process, we can give no assurance that the CPUC would approve the recovery of these additional compliance costs. Perfluorooctane sulfonate (PFOS) and perfluorooctanoic acid (PFOA) are two water contaminants of emerging concern. Although a water quality standard has yet to be set by federal or state regulators, preliminary testing, and guidance from the California Environmental Protection Agency has affected our operations of some wells in California. We expect that a water quality standard will be set in the future and that we will incur costs to comply with the water quality standard. Cal Water has requested and been approved to use a memorandum account to track the incremental compliance costs in the future and we would likely seek permission to recover additional costs of compliance through rate increases; however, we can give no assurance that the CPUC would approve rate increases to enable us to recover these additional compliance costs. Legislation and regulation designed to mitigate or adapt to climate change may affect our operations. Future legislation or regulation regarding climate change may restrict our operations or impose new costs on our business. Our operations depend on power provided by other public utilities and, in emergencies, power generated by our portable and fixed generators. If future legislation or regulation limits emissions from the power generation process, our cost of power may increase. Although any increase in the cost of power would be expected to be passed along to our California customers through the ICBA or included in our cost of service paid by our customers as requested in our GRC filings in California, we can give no assurance that such costs would be passed along to our California customers or that the CPUC would approve rate increases to enable us to recover such expenditures or costs. We have been and may in the future be party to environmental and product-related lawsuits, which could result in us paying damages not covered by insurance. We have been and may be in the future, party to water contamination lawsuits, which may not be fully covered by insurance. The number of environmental and product-related lawsuits against other water utilities has increased in frequency in recent years. If we are subject to additional environmental or product-related lawsuits, we might incur significant legal costs and it is uncertain whether we would be able to recover the legal costs from customers or other third parties. In addition, if current California law regarding CPUC's preemptive jurisdiction over regulated public utilities for claims about compliance with California Department of Health Services and United States EPA water quality standards changes, our legal exposure may be significantly increased. Risks Related to Our Business Operations We may be at risk for litigation under the principle of inverse condemnation for activities in the normal course of business, which have a damaging effect on private property. The

California constitution may allow compensation to property owners for a public utility taking or damaging private property, even when damage occurs through no fault of the utility and regardless of whether the damage could be foreseen by the utility. As a result, this doctrine, which is known as inverse condemnation and is routinely invoked in California, imposes strict liability for damages, including legal fees, because of the design, construction, and maintenance of utility facilities. In addition to claims that our water or wastewater systems damaged property, Cal Water could be sued under inverse condemnation if its facilities or operations damage private property, or if it is unable to timely deliver sufficient quantities of water for firefighting because of system capacity limitations or water supply disruptions, including as a result of action taken by an electric utility pursuant to a PSPS program or other loss of power. Although the imposition of liability is premised on the assumption that utilities have the ability to recover these costs from their customers, there is no assurance that the CPUC would allow Cal Water to recover any such damage awards from customers. For example, in December 2017, the CPUC denied recovery of costs that San Diego Gas Electric Company incurred because of inverse condemnation, holding that the inverse condemnation principles of strict liability are not relevant to the CPUCs prudent manager standard. The effects of natural disasters, attacks by third parties, pandemics, or poor water quality or contamination to our water supply may result in disruption in our services and litigation, which could adversely affect our business, operating results and financial condition. We operate in areas that are prone to earthquakes, fires, mudslides and other natural disasters. A significant seismic event or other natural disaster in California where our operations are concentrated could adversely affect our ability to deliver water and adversely affect our costs of operations. A major disaster could damage or destroy substantial capital assets. The CPUC has historically allowed utilities to establish a catastrophic event memorandum account as another possible mechanism to recover costs. However, we can give no assurance that the CPUC or any other commission would allow any such cost recovery mechanism in the future. Our water supplies are subject to contamination, including contamination from the development of naturally-occurring compounds, chemicals in groundwater systems, pollution resulting from fabricated sources, such as TCP, seawater incursion and possible third-party attacks, including physical attacks, terrorist attacks, and cyber-attacks. If our water supply is contaminated, we may have to interrupt the use of that water supply until we are able to substitute the flow of water from an uncontaminated water source. In addition, we may incur significant costs in order to treat the contaminated source through expansion of our current treatment facilities, or development of new treatment methods. If we are unable to substitute water supply from an uncontaminated water source, or if we are unable to adequately treat the contaminated water source in a cost-effective manner, there may be an adverse effect on our revenues, operating results and financial condition. The costs we incur to decontaminate a water source or an underground water system could be significant and may not be recoverable in rates. We could also be held liable for consequences arising out of human exposure to hazardous substances in our water supplies or other environmental damage. For example, private plaintiffs have the right to bring personal injury or other toxic tort claims arising from the presence of hazardous substances in our drinking water supplies. Our insurance policies may not be sufficient to cover the costs of these claims. We have taken steps to increase security measures at our facilities and heighten employee awareness of threats to our water supply, to protect against third-party attacks, including physical attacks, terrorist attacks, and cyber-attacks. We have also tightened our security measures regarding the delivery and handling of certain chemicals used in our business. We have and will continue to bear increased costs for security precautions to protect our facilities, operations, and supplies. These costs may be significant. Despite these tightened security measures, we may not be able to prevent or deter any third-party attacks or be in a position to control the outcome of third-party attacks should they occur. We depend upon our skilled and trained workforce to ensure water delivery. We can give no assurance that we will be able to maintain sufficient human resources to ensure uninterrupted service in all of the districts that we serve. If any of these catastrophic events were to occur, we can give no assurance that our emergency preparedness plans would be adequate and that we would respond effectively, which could result in public or employee harm or adversely affect our revenues, operating results and financial condition. Failure of critical elements of our infrastructure could result in interruption of service, damage to others, or injuries, and could adversely affect our business, operating results and financial condition. We own physical infrastructure, which was installed over a long period of time, both underground and above-ground. This infrastructure is subject to potential failure due to age, operating conditions, or other unknown factors. Failure of any of our facilities or infrastructure could cause flooding, loss of service to our customers, contamination from chemicals we use in operations, or other damages. We operate a dam. If the dam were to fail for any reason, we would lose a water supply and flooding likely would occur. Whether or not we were responsible for the dam's failure, we could be sued. We can give no assurance that we would be able to defend such a suit successfully. We operate several water and wastewater treatment plants. If a major failure of these facilities were to occur, we would have an interruption in service, potential flooding, and could release potentially harmful material into the environment. We operate over 7,000 miles of underground pipeline. Some failures of underground pipelines could release chemicals into the environment, which have a negative impact on sensitive habitats. We rely on our information technology ("IT") and a number of complex business systems to assist with the management of our business and customer and supplier relationships, and a disruption of these systems could adversely affect our business. Our IT systems are an integral part of our business, and a serious disruption of our IT systems could significantly limit our ability to manage and operate our business efficiently, which, in turn, could cause our business and competitive position to suffer and adversely affect our results of operations. We depend on our IT systems to bill customers, process orders, provide customer service, manage construction projects, manage our financial records, track assets, remotely monitor certain of our plants and facilities and manage human resources, inventory and accounts receivable collections. Our IT systems also enable us to purchase products from our suppliers and bill customers on a timely basis, maintain cost-effective operations, and provide service to our customers. Some of our mission and business critical IT systems are older, such as our Supervisory Control and Data Acquisition system. The steps we have taken to protect our IT systems may be insufficient to protect them from damage or interruption from: power loss, computer systems failures, including hardware equipment and software applications, and internet, telecommunications or data network failures; operator negligence or improper operation by, or supervision of, employees; physical and electronic loss of customer data due to security breaches, cyber-attacks, misappropriation and similar events; computer viruses; intentional security breaches, hacking, denial of services actions, misappropriation of data, and similar events, including intentional cyber security breaches aimed at disrupting and interfering with water treatment processes; and earthquakes, floods, fires, mudslides and other natural disasters or physical attacks. These events may result in physical and/or electronic loss of customer or financial data, security breaches, misappropriation and other adverse consequences, including liability or regulatory penalties under data privacy laws and regulations. In addition, the lack of redundancy for certain of our IT systems, including billing systems, could exacerbate the impact of any of these events on us. In addition, we may not be successful in developing or acquiring technology that is competitive and responsive to the needs of our business, and we might lack sufficient resources to make the necessary upgrades or replacements of our outdated existing technology to allow us to continue to operate at our current level of efficiency, all of which could adversely impact our business and competitive position. The adequacy of our water supplies depends upon a variety of factors beyond our control. Interruption in the water supply may adversely affect our reputation and earnings. We depend on an adequate water supply to meet the present and future needs of our customers. Whether we have an adequate supply varies depending upon a variety of factors, many of which are partially or completely beyond our control, including: the amount of rainfall; the amount of water stored in reservoirs; underground water supply from which well water is pumped; availability from water wholesalers; changes in the amount of water used by our customers; water quality and availability of appropriate treatment technology; legal limitations on water use such as rationing restrictions during a drought; changes in prevailing weather patterns and climate; and population growth. We purchase our water supply from various governmental agencies and others. Water supply availability may be affected by weather conditions, funding and other political and environmental considerations. In addition, our ability to use surface water is subject to regulations regarding water quality and volume limitations. If new regulations are imposed or existing regulations are changed or given new interpretations, the availability of surface water may be materially reduced. A reduction in surface water could result in the need to procure more costly water from other sources, thereby increasing our water production costs and adversely affecting our operating results if not recovered in rates on a timely basis. We have entered into long-term water supply agreements, which commit us to making certain minimum payments whether or not we purchase any water. Therefore, if demand were insufficient to use our required purchases we would have to pay for water we did not receive. From time to time, we enter into water supply agreements with third parties and our business is dependent upon such agreements in order to meet regional demand. For example, we have entered into a water supply contract with the SFPUC that expires on June 30, 2034. We can give no assurance that the SFPUC, or any of the other parties from whom we purchase water, will renew our contracts upon expiration, or that we will not be subject to significant price increases under any such renewed contracts. The parties from whom we purchase water maintain significant infrastructure and systems to deliver water to us. Maintenance of these facilities is beyond our control. If these facilities are not adequately maintained or if these parties otherwise default on their obligations to supply water to us, we may not have adequate water supplies to meet our customers' needs. If we are unable to access adequate water supplies, we may be unable to satisfy all customer demand, which could result in rationing. Rationing may have an adverse effect on cash flow from operations. We can make no guarantee that we will always have access to an adequate supply of water that will meet all required quality standards. Water shortages may affect us in a variety of ways. For example, shortages could: adversely affect our supply mix by causing us to rely on more expensive purchased water; adversely affect operating costs; increase the risk of contamination to our systems due to our inability to maintain sufficient pressure; and increase capital expenditures for building pipelines to connect to alternative sources of supply, new wells to replace those that are no longer in service or are otherwise inadequate to meet the needs of our customers and reservoirs and other facilities to conserve or reclaim water. We may or may not be able to recover increased operating and construction costs on a timely basis, or at all, for our regulated systems through the ratemaking process. We can give no assurance, as to whether we may be able to recover certain of these costs from third parties that may be responsible, or potentially responsible, for any groundwater contamination. Our water supplies and other aspects of our operations may be affected by climate change. There is strong scientific consensus that human activity including carbon and methane emissions is impacting many planetary systems such as the heat-trapping capacity of the atmosphere; ocean temperature, circulation, acidity, and volume; weather patterns including the severity and frequency of severe weather events; ambient temperatures; and planetary ice cover. Because scientific investigations have been focused globally, there is tremendous uncertainty over the timing, extent, and types of impacts global climate change may have on our service areas and in our water supplies. Moreover, studies of tree ring data show long periods of drought conditions have occurred prior to significant human impacts in California and prior to our operation. Finally, in the last fifty years, California has experienced at least three severe multi-year droughts. We can give no assurance that any of our plans for water reliability and water shortages, including incorporating projected and potential climate change risks into our water supply planning activities, will be adequate or capable of effectively addressing any droughts or longer periods of drought conditions or other conditions affecting water quality and availability. Immediate physical risks could affect our operations and intensify over time as climate change worsens. More frequent flooding, wildfires, sea level rise, rising groundwater, and uneven ground level sinking could damage our assets, including pressurized mains and other pipelines, wells, treatment facilities, and other infrastructure. Wildfires and changes in rainfall may also affect water quality, and both higher temperatures and wildfires can pose risks to employee safety. Farther into the mid-century and late-century horizon, temperature increases may cause declines in snowpack storage, and droughts could decrease surface water supply availability and groundwater recharge while causing increased outdoor demands. Additional climate-related risks may influence our approach as we support the transition to a low-carbon economy. Transition risks include changes in the market and consumer demands, such as differences in generational behaviors, shifts in population locations due to the pandemic and different weather patterns, and variations in water needs and customer groups. Regulatory risks, such as emission trading systems and carbon taxes, may also financially affect our business. Additionally, federal and state regulations present requirements for managing water supplies and limiting impacts on local wildlife, while regional plans and legislation may directly affect how we address water issues. We also periodically review the climate change plans of our wholesalers to determine whether alternative supplies may be necessary in the future. However, we can give no assurance that replacement water supplies will be available at a reasonable cost or a cost acceptable to our customers and Commissions. Natural disasters, climate change, economic conditions and other factors may change the population in our service areas. In the event that some outside factor such as a wildfire, flood, changed climate pattern, actual or threatened public health emergency, or change in the local economy reduces or eliminates our customer base in a service area, or negatively affects the ability of a customer to pay, we could face unrecoverable costs. In those circumstances, the remaining customers might not be able to pay for the operating costs or capital costs of the water system. We may not be able to recover capital costs of property that is no longer used and useful in utility service. We may also encounter an increase in bad debt expense in times of economic difficulty. For example, we experienced an increase in bad debt expense in 2022, which we believe is due to economic impact of the COVID-19 pandemic. Although we would likely seek permission to recover these costs through rate increases on remaining customers or in statewide rates, we can give no assurance that the Commissions would approve rate increases to enable us to recover these costs. Wastewater operations entail significant risks. Wastewater collection and treatment involve many risks associated with damage to the environment, and we anticipate that wastewater collection and treatment will become an increasing significant part of our business. If collection or treatment systems fail or do not operate properly, untreated or partially treated wastewater could discharge onto property or into nearby streams and rivers, causing damage or injury to property, aquatic life, or human life. Our results of operations and financial condition could be materially and adversely affected by liabilities resulting from such damage. Demand for our water is subject to various factors and is affected by seasonal fluctuations. Demand for our water during the warmer, dry months is generally greater than during cooler or rainy months due primarily to additional requirements for water in connection with irrigation systems, swimming pools, cooling systems and other outside water use. Throughout the year, and particularly during typically warmer months, demand will vary with temperature and rainfall levels. If temperatures during the typically warmer months are cooler than normal, or if there is more rainfall than normal, the demand for our water may decrease. Under the MWRAM mechanism, lower water usage in our California operations affects our cash flows in the year of usage, but results in higher cash flows in the following years. In addition, governmental restrictions on water usage during drought conditions may result in a decreased demand for our water, even if our water reserves are sufficient to serve our customers during these drought conditions. The Commissions may not allow surcharges to collect lost revenues caused by customers' conservation during a drought. Regardless of whether we may surcharge our customers during a conservation period, they may use less water even after a drought has passed because of conservation patterns developed during the drought. Furthermore, our customers may wish to use recycled water as a substitute for potable water. If rights are granted to others to serve our customers recycled water, there will likely be a decrease in demand for our water. Finally, changes in prevailing weather patterns due to climate change may affect customer demand. If increased ambient temperatures affect our service areas, water used for irrigation and cooling may increase. If rainfall patterns change, our customers may change their patterns of water use including the amount of outdoor irrigation and the type of landscape they install. Government agencies may also mandate changes to customer irrigation or landscape patterns in response to changes in weather and climate. Changes in water supply costs affect our operations. The cost to obtain water for delivery to our customers varies depending on the sources of supply, wholesale suppliers' prices, the quality of water required to be treated and the quantity of water produced to fulfill customer water demand. Our source of supply varies among our operating districts. Certain districts obtain all of their supply from wells; some districts purchase all of the supply from wholesale suppliers; and other districts obtain the supply from a combination of wells and wholesale suppliers. A small portion of supply comes from surface sources and is processed through Company-owned water treatment plants. On average, slightly more than half of the water we deliver to our customers is pumped from wells or received from a surface supply with the remainder purchased from wholesale suppliers. Water purchased from suppliers usually costs us more than surface supplied or well pumped water. The cost of purchased water for delivery to customers represented 31.2% and 33.9% of our total operating costs in 2022 and 2021, respectively. Water purchased from suppliers will require renewal of our contracts upon expiration and may result in significant price increases under any such renewed contracts. Wholesale water suppliers may increase their prices for water delivered to us based on factors that affect their operating costs. Purchased water rate increases are beyond our control. In California, our ability to recover increases in the cost of purchased water is expected to change with the adoption of the ICBA, which is effective as of January 1, 2023. With this change, actual per-unit purchased water costs are expected to be compared to authorized per-unit purchased water costs, with variances added to or netted against the variances in purchased power and pump taxes being recorded as a cost recovery. The balance in the ICBA is expected to be collected in the future by billing the ICBA accounts receivable balances over future periods, which may have a short-term negative impact on cash flow. Dependency upon adequate supply of electricity, certain chemicals, and third-party suppliers of parts and skilled labor could adversely affect our results of operations. Purchased electrical power is required to operate the wells and pumps needed to supply water to our customers. Although there are back-up power generators to operate a number of wells and pumps in emergencies, an extended interruption in power could affect the ability to supply water. In the past, California has been subject to rolling power blackouts due to insufficient power supplies. There is no assurance we will not be subject to power blackouts in the future. Additionally, we require sufficient amounts of certain chemicals in order to treat the water we supply. There are multiple sources for these chemicals but an extended interruption of supply could adversely affect our ability to adequately treat our water. Purchased power is a significant operating expense. During 2022 and 2021, purchased power expense represented 6.2% and 5.6%, respectively, of our total operating costs. These costs are beyond our control and can change unpredictably and substantially as occurred in California during 2001 when rates paid for electricity increased 48%. As with purchased water, purchased power costs are expected to be included in the ICBA. Cash flows between rate filings may be adversely affected until the Commission authorizes a rate change, but earnings will be minimally impacted. Cost of chemicals used in the delivery of water is not an element of the ICBA, and therefore, variances in quantity or cost could affect the results of operations. We rely on outside contractors to supply us with materials and parts critical to the operation of our systems. Should parts and material become unavailable, or should the cost of necessary supplies rise substantially, it could adversely affect our ability to operate or have financial affects that are not recoverable through a regulatory process. We also rely on outside contractors to complete large construction projects and provide emergency maintenance services. In the event these contractors are unavailable or cannot meet the demands imposed on them, we may face significantly lengthy interruptions of service or delays in constructing capital projects. We may face additional costs to acquire more resources to complete these activities. Our business requires significant capital expenditures to replace or improve aging infrastructure that are dependent on our ability to secure appropriate funding. If we are unable to obtain sufficient capital or if the rates at which we borrow increase, there would be a negative impact on our results of operations. The water utility business is capital-intensive. We invest significant funds to replace or improve aging infrastructure such as property, plant, and equipment. In addition, water shortages may adversely affect us by causing us to rely on more purchased water. This could cause increases in capital expenditures needed to build pipelines to secure alternative water sources. In addition, we require capital to grow our business through acquisitions. We fund our short-term capital requirements from cash received from operations and funds received from developers. We seek to meet our long-term capital needs by raising equity through common or preferred stock issues or issuing debt obligations. We cannot give any assurance that these sources will continue to be adequate or that the cost of funds will remain at levels permitting us to earn a reasonable rate of return. In the event we are unable to obtain sufficient capital, our expansion efforts could be curtailed, which may affect our growth and may affect our future results of operations. Our ability to access the capital markets is affected by the ratings of certain of our debt securities. Standard Poor's Rating Agency issues a rating on California Water Service Company's ability to repay certain debt obligations. The credit rating agency could downgrade our credit rating based on reviews of our financial performance and projections or upon the occurrence of other events that could affect our business outlook. Lower ratings by the agency could restrict our ability to access equity and debt capital. We can give no assurance that the rating agency will maintain ratings that allow us to borrow under advantageous conditions and at reasonable interest rates. A future downgrade by the agency could also increase our cost of capital by causing potential investors to require a higher interest rate due to a perceived risk related to our ability to repay outstanding debt obligations. While the majority of our debt is long term at fixed rates, we do have interest rate exposure in our short-term borrowings, which have variable interest rates. We are also subject to interest rate risks on new financings. However, if interest rates were to increase on a long-term basis, our management believes that customer rates would increase accordingly, subject to approval by the appropriate commission. We can give no assurance that the Commission would approve such an increase in customer rates. We are obligated to comply with specified debt covenants under certain of our loan and debt agreements. Failure to maintain compliance with these covenants could limit future borrowing, and we could face increased borrowing costs, litigation, acceleration of maturity schedules, and cross default issues. Such actions by our creditors could have a material adverse effect on our financial condition and results of operations. Our inability to access the capital or financial markets could affect our ability to meet our liquidity needs at reasonable cost and our ability to meet long-term commitments. Changes in economic conditions in our markets could affect our customers' ability to pay for water services. Any of these could adversely affect our results of operations, cash flows, and financial condition. We rely on our current credit facilities to fund short-term liquidity needs if internal funds are not available from operations. Specifically, given the seasonal fluctuations in demand for our water we commonly draw on our credit facilities to meet our cash requirements at times in the year when demand is relatively low. We also may occasionally use letters of credit issued under our revolving credit facilities. Disruptions in the capital and credit markets could adversely affect our ability to draw on our credit facilities. Our access to funds under our credit facilities is dependent on the ability of our banks to meet their funding commitments. Many of our customers and suppliers also have exposure to risks that could affect their ability to meet payment and supply commitments. We operate in geographic areas that may be particularly susceptible to declines in the price of real property, which could result in significant declines in demand for our products and services. In the event that any of our significant customers or suppliers, or a significant number of smaller customers and suppliers, are adversely affected by these risks, we may face disruptions in supply, significant reductions in demand for our products and services, inability of customers to pay invoices when due, and other adverse effects that could negatively affect our financial condition, results of operations and/or cash flows. Our operations and certain contracts for water distribution and treatment depend on the financial capability of state and local governments, and other municipal entities such as water districts. Major disruptions in the financial strength or operations of such entities, such as liquidity limitations, bankruptcy or insolvency, could have an adverse effect on our ability to conduct our business and/or enforce our rights under contracts to which such entities are a party. We are a holding company that depends on cash flow from our subsidiaries to meet our obligations and to pay dividends on our common stock. As a holding company, we conduct substantially all of our operations through our subsidiaries and our only significant assets are investments in those subsidiaries. 91.6% of our revenues are derived from the operations of California Water Service Company. As a result, we are dependent on cash flow from our subsidiaries, and California Water Service Company in particular, to meet our obligations and to pay dividends on our common stock. Our subsidiaries are separate and distinct legal entities and generally have no obligation to pay any amounts due on California Water Service Group's debt or to provide California Water Service Group with funds for dividends. Although there are no contractual or regulatory restrictions on the ability of our subsidiaries to transfer funds to us, the reasonableness of our capital structure is one of the factors considered by state and local regulatory agencies in their ratemaking determinations. Therefore, transfer of funds from our subsidiaries to us for the payment of our obligations or dividends may have an adverse effect on ratemaking determinations. Furthermore, our right to receive cash or other assets upon the liquidation or reorganization of a subsidiary is generally subject to the prior claims of creditors of that subsidiary. If we are unable to obtain funds from our subsidiaries in a timely manner, we may be unable to meet our obligations or pay dividends. We can make dividend payments only from our surplus (the excess, if any, of our net assets over total paid-in capital) or if there is no surplus, the net profits for the current fiscal year or the fiscal year before which the dividend is declared. In addition, we can pay cash dividends only if after paying those dividends we would be able to pay our liabilities as they become due. Owners of our capital stock cannot force us to pay dividends and dividends will only be paid if and when declared by our board of directors. Our board of directors can elect at any time, and for an indefinite duration, not to declare dividends on our capital stock. An important element of our growth strategy is the acquisition of water and wastewater systems. Risks associated with potential acquisitions, divestitures or restructurings may adversely affect us. We may seek to acquire or invest in other companies, technologies, services, or products that complement our business. The execution of our growth strategy may expose us to different risks than those associated with our utility operations. We can give no assurance that we will succeed in finding attractive acquisition candidates or investments, or that we would be able to reach mutually agreeable terms with such parties. In addition, as consolidation becomes more prevalent in the water and wastewater industries, the prices for suitable acquisition candidates may increase to unacceptable levels and limit our ability to grow through acquisitions. If we are unable to find acquisition candidates or investments, our ability to grow may be limited. Acquisition and investment transactions may result in the issuance of our equity securities that could be dilutive if the acquisition or business opportunity does not develop in accordance with our business plan. They may also result in significant write-offs and an increase in our debt. The occurrence of any of these events could have a material adverse effect on our business, financial condition, and results of operations. Any of these transactions could involve numerous additional risks, including one or more of the following: problems integrating the acquired operations, personnel, technologies, physical and cyber security processes, or products with our existing businesses and products; liabilities inherited from the acquired companies' prior business operations; diversion of management time and attention from our core business to the acquired business; failure to retain key technical, management, and other personnel of the acquired business; difficulty in retaining relationships with suppliers and customers of the acquired business; and difficulty in obtaining required regulatory approvals. In addition, the businesses and other assets we acquire may not achieve the sales and profitability expected. The occurrence of one or more of these events may have a material adverse effect on our business. There can be no assurance that we will be successful in overcoming these or any other significant risks encountered. We may not be able to increase or sustain our recent growth rate, and we may not be able to manage our future growth effectively. We may be unable to continue to expand our business or manage future growth. To successfully manage our growth and handle the responsibilities of being a public company, we must effectively: hire, train, integrate and manage additional qualified engineers for engineering design and construction activities, new business personnel, and financial and information technology personnel; retain key management, augment our management team, and retain qualified and certified water and wastewater system operators; implement and improve additional and existing administrative, financial and operations systems, procedures and controls; expand our technological capabilities; and manage multiple relationships with our customers, regulators, suppliers and other third parties. If we are unable to manage our growth effectively, we may not be able to take advantage of market opportunities, satisfy customer requirements, execute our business plan, or respond to competitive pressures. We have a number of large-volume commercial and industrial customers and a significant decrease in consumption by one or more of these customers could have an adverse effect on our operating results and cash flows. Our billed revenues and cash flows from operations will decrease if a significant business or industrial customer terminates or materially reduces its use of our water. Approximately $180.2 million, or 23.3%, of our 2022 water utility revenues was derived from business and industrial customers. In Hawaii, we serve a number of large resorts, which if their water usage was reduced or ceased could have a material impact to our Hawaii operation. The delay between such date and the effective date of the rate relief may be significant and could adversely affect our operating results and cash flows. Our operating cost and costs of providing services may rise faster than our revenues. Our ability to increase rates over time is dependent upon approval of such rate increases by the Commissions, or in the case of the City of Hawthorne and the City of Commerce, the City Council, which may be inclined, for political or other reasons, to limit rate increases. However, our costs, which are subject to market conditions and other factors, may increase significantly. The second largest component of our operating costs after water production is made up of salaries and wages. These costs are affected by the local supply and demand for qualified labor. Other large components of our costs are general insurance, workers compensation insurance, employee benefits and health insurance costs. These costs may increase disproportionately to rate increases authorized by the Commissions and may have a material adverse effect on our future results of operations. Demand for our stock may fluctuate due to circumstances beyond our control. We believe that stockholders invest in public utility stocks, in part, because they seek reliable dividend payments. If there is an over-supply of stock of public utilities in the market relative to demand by such investors, the trading price of our securities could decrease. Additionally, if interest rates rise above the dividend yield offered by our equity securities, demand for our stock, and consequently its market price, may decrease. A decline in demand for our stock may have a negative impact on our ability to finance capital projects. Adverse investment returns and other factors may increase our pension liability and pension funding requirements. A substantial number of our employees are covered by a defined benefit pension plan. At present, the pension plan is underfunded because our projected pension benefit obligation exceeds the aggregate fair value of plan assets. Under applicable law, we are required to make cash contributions to the extent necessary to comply with minimum funding levels imposed by regulatory requirements. The amount of such required cash contribution is based on an actuarial valuation of the plan. The funded status of the plan can be affected by investment returns on plan assets, discount rates, mortality rates of plan participants, pension reform legislation and a number of other factors. There can be no assurance that the value of our pension plan assets will be sufficient to cover future liabilities. Although we contributed to our pension plan in recent years, it is possible that we could incur a pension liability adjustment, or could be required to make additional cash contributions to our pension plan, which would reduce the cash available for business and other needs. Labor relations matters could adversely affect our operating results. At December 31, 2022, 744 of our 1,225 total employees were union employees. Most of our unionized employees are represented by the Utility Workers Union of America, AFL-CIO, except certain engineering and laboratory employees who are represented by the International Federation of Professional and Technical Engineers, AFL-CIO. We believe our labor relations are good, but in light of rising costs for health care and pensions, our current contract negotiations and those in the future may be difficult. Furthermore, changes in applicable law or regulations could have an adverse effect on management's negotiating position with respect to our currently unionized employees and/or employees that decide to unionize in the future. We are subject to a risk of work stoppages and other labor relations matters as we negotiate with the unions to address these issues, which could affect our results of operations and financial condition. We can give no assurance that issues with our labor forces will be resolved favorably to us in the future or that we will not experience work stoppages. Our operations are geographically concentrated in California and this lack of diversification may negatively affect our operations. Although we own facilities in a number of states, over 91.6% of our operations are located in California. As a result, we are largely subject to weather, political, water supply, labor, energy cost, regulatory, and economic risks affecting California. We are also affected by the real property market in California. In order to grow our business, we may need to acquire additional real estate or rights to use real property owned by third parties, the cost of which tends to be higher and more volatile in California than in other states. The value of our assets in California may decline if there is a decline in the California real estate market that results in a significant decrease in real property values. Municipalities, water districts and other public agencies may condemn our property by eminent domain action. State statutes allow municipalities, water districts and other public agencies to own and operate water systems. These agencies are empowered to condemn water systems or real property owned by privately owned public utilities in certain circumstances and in compliance with California and federal law. Additionally, whenever a public agency constructs facilities to extend its utility system into the service area of a privately owned public utility, such an act may constitute the taking of property and require reimbursement to the public utility for its loss. If a public agency were to file an eminent domain lawsuit against us, we would incur substantial attorneys fees, consultant and expert fees, and other costs in considering a challenge to the right to take our utility property and/or its valuation for just compensation, as well as such fees and costs in any subsequent litigation if necessary. If the public agency prevailed and acquired our utility property, we would be entitled to just compensation for our loss, but we would no longer have access to the condemned property or water system. Neither would we be entitled to any portion of revenue generated from the use of such asset going forward. The Ongoing COVID-19 Pandemic May Adversely Affect Our Operations Although the COVID-19 pandemic did not have a significant impact on our business in 2022, we are unable to accurately predict the full impact that the ongoing COVID-19 pandemic will have on our business, results of operations, financial condition or liquidity due to numerous uncertainties, including the duration and severity of the outbreak, potential resurgence and /or mutations of the virus, and the development, distribution and public acceptance of treatments and vaccines. As an essential business during times of emergencies pursuant to the U.S. Critical Infrastructures Protection Act of 2001, we are working to continue to provide water and wastewater services to our two million customers. If we close any of our facilities due to a COVID-19 outbreak or if a critical number of our employees become too ill to work, our business operations could be materially adversely affected in a rapid manner. General Risk Factors We depend significantly on the services of the members of our management team, and the departure of any of those persons could cause our operating results to suffer. Our success depends significantly on the continued individual and collective contributions of our management team. The loss of the services of any member of our management team could have an adverse effect on our business as our management team has knowledge of our industry and customers and would be difficult to replace. We retain certain risks not covered by our insurance policies. We evaluate our risks and insurance coverage annually or more frequently if circumstances dictate. Our evaluation considers the costs, risks, and benefits of retaining versus insuring various risks as well as the availability of certain types of insurance coverage. Accordingly, we have determined or may determine to self-insure or to not obtain insurance in certain cases, or insurance may not be available at commercially acceptable terms or at all. Furthermore, we are also affected by increases in prices for insurance coverage; in particular, we have been, and will continue to be, affected by rising health insurance costs. Retained risks are associated with deductible limits, partial self-insurance programs, and insurance policy coverage ceilings. If we suffer an uninsured loss, we may be unable to pass all or any portion of the loss on to customers, because our rates are regulated by regulatory commissions. Consequently, uninsured losses may negatively affect our financial condition, liquidity, and results of operations. There can be no assurance that we will not face uninsured losses pertaining to the risks we have retained. Our enterprise risk management processes may not be effective in identifying and mitigating the risks to which we are subject, or in reducing the potential for losses in connection with such risks. Our enterprise risk management processes are designed to minimize or mitigate the risks to which we are subject, as well as any losses stemming from such risks. Although we seek to identify, measure, monitor, report, and control our exposure to such risks, and employ a broad and diversified set of risk monitoring and mitigation techniques in the process, those techniques are inherently limited in their ability to anticipate the existence or development of risks that are currently unknown and unanticipated. The ineffectiveness of our enterprise risk management processes in mitigating the impact of known risks or the emergence of previously unknown or unanticipated risks may result in our incurring losses in the future that could adversely affect our financial condition and results of operations. The accuracy of our judgments and estimates about financial and accounting matters will affect our operating results and financial condition. We make certain estimates and judgments in preparing our financial statements regarding, among others: the useful life of intangible rights; the number of years to depreciate certain assets; amounts to set aside for uncollectible accounts receivable, inventory obsolescence and uninsured losses; our legal exposure and the appropriate accrual for claims, including medical claims and workers' compensation claims; future costs and assumptions for pensions and other postretirement benefits; regulatory recovery of regulatory assets; possible tax uncertainties; and projected collections of WRAM and MCBA receivables or receivables under subsequent recovery mechanisms, such as MWRAM and ICBA. The quality and accuracy of those estimates and judgments may have an impact on our operating results and financial condition. In addition, we must estimate unbilled revenues and costs as of the end of each accounting period. If our estimates are not accurate, we would be required to make an adjustment in a future period. Accounting rules permit us to use expense balancing accounts and memorandum accounts that include cost changes to us that are different from amounts incorporated into the rates approved by the Commissions. These accounts result in expenses and revenues being recognized in periods other than in which they occurred. We identified a material weakness in our internal control over financial reporting, and, if not remediated effectively, our ability to produce timely and accurate financial statements or comply with applicable laws and regulations could be impaired, which could result in loss of investor confidence in the accuracy and completeness of our financial reports and materially adversely affect our results of operations and stock price. The accuracy of our financial reporting is dependent on the effectiveness of our internal controls. We are required to provide a report from management to our stockholders on our internal control over financial reporting that includes an assessment of the effectiveness of these controls. As disclosed in Part II, Item 9A, management concluded that our internal control over financial reporting was not effective as of December 31, 2022 due to a material weakness in our internal control over the completeness of our accounting for regulatory assets and liabilities, specifically controls over the identification of regulatory filings by the Company during the period that are then reviewed to determine their potential accounting impact. This material weakness has not yet been remediated and remained at the time of the preparation of our financial statements for the year ended December 31, 2022. We can provide no assurance that our remediation plan to address this material weakness, including, but not limited to, revising the design of existing controls and implementing new controls, will be successful. Internal control over financial reporting has inherent limitations, including human error, the possibility that controls could be circumvented or become inadequate because of changed conditions, and fraud. Because of these inherent limitations, internal control over financial reporting might not prevent or detect all misstatements or fraud. If we are unable to remediate the material weakness in a timely manner, or are otherwise unable to maintain effective internal control over financial reporting or disclosure controls and procedures, we could suffer harm to our reputation, incur incremental compliance costs, fail to meet our public reporting requirements on a timely basis, be unable to properly report on our business and our results of operations, or be required to restate our financial statements, which could result in loss of investor confidence in the accuracy and completeness of our financial reports, subject us to litigation or investigations requiring management resources and payment of legal and other expenses, and our results of operations and our stock price could be materially adversely affected.

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I TEM 1. Business. Corporate Overview and Strategy Chesapeake Utilities Corporation is a Delaware corporation formed in 1947 with operations primarily in the Mid-Atlantic region, North Carolina, South Carolina, Florida and Ohio. We are an energy delivery company engaged in the distribution of natural gas, electricity and propane; the transmission of natural gas; the generation of electricity and steam, and in providing related services to our customers. Our strategy is focused on growing earnings from a stable regulated energy delivery foundation and investing in related businesses and services that provide opportunities for returns greater than traditional utility returns. We seek to identify and develop opportunities across the energy value chain, with emphasis on midstream and downstream investments that are accretive to earnings per share, consistent with our long-term growth strategy and create opportunities to continue our record of top tier returns on equity relative to our peer group. The Companys growth strategy includes the continued investment and expansion of the Companys regulated operations that provide a stable base of earnings, as well as investments in other related non-regulated businesses and services including sustainable energy initiatives. By investing in these related business and services, the Company creates opportunities to sustain its track record of higher returns, as compared to a traditional utility. ##TABLE_START Currently, the Companys growth strategy is focused on the following platforms, including: Optimizing the earnings growth in our existing businesses, which includes organic growth, territory expansions, and new products and services as well as increased opportunities to transform the Company with a focus on people, process, technology and organizational structure. Identification and pursuit of additional pipeline expansions, including new interstate and intrastate transmission projects. Growth of Marlin Gas Services CNG transport business and expansion into LNG and RNG transport services as well as methane capture. Identifying and undertaking additional strategic propane acquisitions that provide a larger foundation in current markets and expand our brand and presence into new strategic growth markets. Pursuit of growth opportunities that enable us to utilize our integrated set of energy delivery businesses to participate in sustainable energy opportunities. ##TABLE_ENDOperating Segments We conduct operations within two reportable segments: Regulated Energy and Unregulated Energy. The remainder of our operations is presented as Other businesses and eliminations." These segments are described below in detail. Regulated Energy Overview Our regulated energy businesses are comprised of natural gas and electric distribution, as well as natural gas transmission services. The following table presents net income for the year ended December 31, 2022 and total assets as of December 31, 2022, by operation and area served: Chesapeake Utilities Corporation 2022 Form 10-K Page 3 ##TABLE_START Operations Areas Served Net Income Total Assets (in thousands) Natural Gas Distribution Delmarva Natural Gas (1) Delaware/Maryland $ 12,930 $ 387,045 Florida Natural Gas (2) Florida 19,162 507,798 Natural Gas Transmission Eastern Shore Delaware/Maryland/ Pennsylvania 23,222 477,905 Peninsula Pipeline Florida 10,372 142,702 Aspire Energy Express Ohio 439 7,235 Electric Distribution FPU Florida 3,951 193,570 Total Regulated Energy $ 70,076 $ 1,716,255 ##TABLE_END(1) Delmarva Natural Gas consists of Delaware division, Maryland division, Sandpiper Energy and Elkton Gas. (2) Florida Natural Gas consists of Chesapeake Utilities CFG Division and FPU, and FPU's Ft. Meade and Indiantown divisions. Revenues in the Regulated Energy segment are based on rates regulated by the PSC in the states in which we operate or, in the case of Eastern Shore, which is an interstate business, by the FERC. The rates are designed to generate revenues to recover all prudent operating and financing costs and provide a reasonable return for our stockholders. Each of our distribution and transmission operations has a rate base, which generally consists of the original cost of the operation's plant (less accumulated depreciation), working capital and other assets. For Delmarva Natural Gas and Eastern Shore, rate base also includes deferred income tax liabilities and other additions or deductions. Our Regulated Energy operations in Florida do not include deferred income tax liabilities in their rate base. Our natural gas and electric distribution operations bill customers at standard rates approved by their respective state PSC. Each state PSC allows us to negotiate rates, based on approved methodologies, for large customers that can switch to other fuels. Some of our customers in Maryland receive propane through underground distribution systems in Worcester County. We bill these customers under PSC-approved rates and include them in the natural gas distribution results and customer statistics. Our natural gas and electric distribution operations earn profits on the delivery of natural gas or electricity to customers. The cost of natural gas or electricity that we deliver is passed through to customers under PSC-approved fuel cost recovery mechanisms. The mechanisms allow us to adjust our rates on an ongoing basis without filing a rate case to recover changes in the cost of the natural gas and electricity that we purchase for customers. Therefore, while our distribution operating revenues fluctuate with the cost of natural gas or electricity we purchase, our distribution adjusted gross margin is generally not impacted by fluctuations in the cost of natural gas or electricity. Our natural gas transmission operations bill customers under rate schedules approved by the FERC or at rates negotiated with customers. Operational Highlights The following table presents operating revenues, volumes and the average number of customers by customer class for our natural gas and electric distribution operations for the year ended December 31, 2022: Chesapeake Utilities Corporation 2022 Form 10-K Page 4 ##TABLE_START Delmarva Natural Gas Distribution Florida Natural Gas Distribution (2) FPU Electric Distribution Operating Revenues (in thousands) Residential $ 83,373 60 % $ 46,824 30 % $ 38,954 48 % Commercial 40,912 29 % 38,714 25 % 37,524 46 % Industrial 12,171 9 % 59,704 38 % 2,586 3 % Other (1) 2,803 2 % 10,628 7 % 2,650 3 % Total Operating Revenues $ 139,259 100 % $ 155,870 100 % $ 81,714 100 % Volumes (in Dts for natural gas/MW Hours for electric) Residential 4,645,336 30 % 2,086,597 5 % 305,593 48 % Commercial 4,167,454 27 % 6,453,918 15 % 304,816 48 % Industrial 6,234,637 41 % 31,448,883 72 % 20,969 3 % Other 307,397 2 % 3,418,788 8 % 5,978 1 % Total Volumes 15,354,824 100 % 43,408,186 100 % 637,356 100 % Average Number of Customers (3) Residential 92,694 92 % 85,074 91 % 25,516 78 % Commercial 7,906 8 % 5,728 6 % 7,349 22 % Industrial 215 1% 2,594 3 % 2 1% Other 4 1% 6 1% % Total Average Number of Customers 100,819 100 % 93,402 100 % 32,867 100 % ##TABLE_END(1) Operating Revenues from "Other" sources include revenue, unbilled revenue, under (over) recoveries of fuel cost, conservation revenue, other miscellaneous charges, fees for billing services provided to third parties, and adjustments for pass-through taxes. (2) Florida natural gas distribution includes Chesapeake Utilities' CFG division,, FPU and FPU's Indiantown and Fort Meade divisions. (3) Average number of customers is based on the twelve-month average for the year ended December 31, 2022. The following table presents operating revenues, by customer type, for Eastern Shore and Peninsula Pipeline for the year ended December 31, 2022, as well as contracted firm transportation capacity by customer type, and design day capacity at December 31, 2022. Aspire Energy Express has been excluded from the table below and had operating revenue of $1.4 million and firm transportation capacity of 300,000 Dts/d for the year ended December 31, 2022: ##TABLE_START Eastern Shore Peninsula Pipeline Operating Revenues (in thousands) Local distribution companies - affiliated (1) $ 32,458 41 % $ 23,669 87 % Local distribution companies - non-affiliated 22,943 29 % 840 3 % Commercial and industrial - affiliated % 1,120 4 % Commercial and industrial - non-affiliated 23,213 30 % 264 1 % Other (2) 10 1% 1,376 5 % Total Operating Revenues $ 78,624 100 % $ 27,269 100 % Contracted firm transportation capacity (in Dts/d) Local distribution companies - affiliated 154,379 50 % 306,400 36 % Local distribution companies - non-affiliated 56,576 18 % 534,825 63 % Commercial and industrial - affiliated % 8,300 1 % Commercial and industrial - non-affiliated 98,540 32 % 5,100 1% Total Contracted firm transportation capacity 309,495 100 % 854,625 100 % Design day capacity (in Dts/d) 309,495 100 % 854,625 100 % ##TABLE_END(1) Eastern Shore's and Peninsula Pipeline's service to our local distribution affiliates is based on the respective regulator's approved rates and is an integral component of the cost associated with providing natural gas supplies to the end users of those affiliates. We eliminate operating revenues of these entities against the natural gas costs of those affiliates in our consolidated financial information; however, our local distribution affiliates include this amount in their purchased fuel cost and recover it through fuel cost recovery mechanisms. (2) Operating revenues from "Other" sources are from the rental of gas properties. Chesapeake Utilities Corporation 2022 Form 10-K Page 5 Regulatory Overview The following table highlights key regulatory information for each of our principal Regulated Energy operations. Peninsula Pipeline and Aspire Energy Express are not regulated with regard to cost of service by either the Florida PSC or Ohio PUC respectively, or FERC and are therefore excluded from the table. See Item 8, Financial Statements and Supplementary Data (Note 18, Rates and Other Regulatory Activities, in the consolidated financial statements) for further discussion on the impact of this legislation on our regulated businesses. ##TABLE_START Natural Gas Distribution Delmarva Florida Electric Distribution Natural Gas Transmission Operation/Division Delaware Maryland Sandpiper Elkton Gas (7) Chesapeake's CFG division FPU FPU Eastern Shore Regulatory Agency Delaware PSC Maryland PSC Florida PSC FERC Effective date - Last Rate Order 01/01/2017 12/1/2007 12/01/2019 02/07/2019 01/14/2010 01/14/2010 (1) 10/8/2020 08/01/2017 Rate Base (in Rates) (in Millions) Not stated Not stated Not stated Not stated $46.7 $68.9 $24.9 Not stated Annual Rate Increase Approved (in Millions) $2.3 $0.6 N/A (2) $0.1 $2.5 $8.0 $3.4 base rate and $7.7 from storm surcharge $9.8 Capital Structure (in rates) (3)* Not stated LTD: 42% STD: 5% Equity: 53% Not stated LTD: 50% Equity: 50% LTD: 31% STD: 6% Equity: 43% Other: 20% LTD: 31% Equity: 47% Other: 22% LTD: 22% STD: 23% Equity: 55% Not stated Allowed Return on Equity 9.75% (4) 10.75% (4) Not stated (5) 9.80% 10.80% (4) 10.85% (4) 10.25% (4), (6) Not stated TJCA Refund Status associated with customer rates Refunded Refunded Refunded N/A Retained Retained Refunded Refunded ##TABLE_END(1) The effective date of the order approving the settlement agreement, which adjusted the rates originally approved on June 4, 2009. (2) The Maryland PSC approved a declining return on equity that will result in a decline in our rates. (3) Other components of capital structure include customer deposits, deferred income taxes and tax credits. (4) Allowed after-tax return on equity. (5) The terms of the agreement include revenue neutral rates for the first year (December 1, 2016 through

November 30, 2017), followed by a schedule of rate reductions in subsequent years based upon the projected rate of propane to natural gas conversions. (6) The terms of the settlement agreement for the FPU electric division limited proceeding with the Florida PSC prescribed an authorized return on equity range of 9.25 to 11.25 percent, with a mid-point of 10.25 percent. (7) The rate increase and allowed return on equity for Elkton Gas were approved by the Maryland PSC before we acquired the company. * LTD-Long-term debt; STD-Short-term debt. In May 2022, our natural gas distribution businesses in Florida (FPU, FPU-Indiantown division, FPU-Fort Meade division and Chesapeake Utilities CFG division, collectively, Florida natural gas distribution businesses) filed a consolidated natural gas rate case with the Florida PSC. The application included a request for the following: (i) permanent rate relief of approximately $24.1 million, effective January 1, 2023; (ii) a depreciation study also submitted with the filing; (iii) authorization to make certain changes to tariffs to include the consolidation of rates and rate structure across the businesses and to unify the Florida natural gas distribution businesses under FPU; (iv) authorization to retain the acquisition adjustment recorded at the time of the FPU merger in our revenue requirement; and (v) authorization to establish an environmental remediation surcharge for the purposes of addressing future expected remediation costs for FPU MGP sites. In August 2022, interim rates were approved by the Florida PSC in the amount of approximately $7.7 million on an annualized basis, effective for all meter readings in September 2022. The discovery process and subsequent hearings were concluded during the fourth quarter of 2022 and briefs were submitted in the same quarter of 2022. In January 2023, the Florida PSC approved the application for consolidation and permanent rate relief of approximately $17.2 million on an annual basis. Actual rates in connection with the rate relief were approved by the Florida PSC in February 2023 with an effective date of March 1, 2023. The following table presents surcharge and other mechanisms that have been approved by the respective PSC for our regulated energy distribution businesses. These include Delaware surcharges to expand natural gas service in its service territory as well as for the conversion of propane distribution systems to natural gas, Marylands surcharges to fund natural gas conversions and system improvements in Worcester County, Elkton's STRIDE plan for accelerated pipeline replacement for older portions of the natural gas distribution system, Floridas GRIP surcharge which provides accelerated recovery of the Chesapeake Utilities Corporation 2022 Form 10-K Page 6 costs of replacing older portions of the natural gas distribution system to improve safety and reliability and the Florida electric distribution operation's limited proceeding which allowed recovery of storm-related costs . ##TABLE_START Operation(s)/Division(s) Jurisdiction Infrastructure mechanism Revenue normalization Delaware division Delaware Yes No Maryland division Maryland No Yes Sandpiper Energy Maryland Yes Yes Elkton Gas Maryland Yes Yes FPU and CFG natural gas divisions Florida Yes No FPU electric division Florida Yes No ##TABLE_ENDWeather Weather variations directly influence the volume of natural gas and electricity sold and delivered to residential and commercial customers for heating and cooling and changes in volumes delivered impact the revenue generated from these customers. Natural gas volumes are highest during the winter months, when residential and commercial customers use more natural gas for heating. Demand for electricity is highest during the summer months, when more electricity is used for cooling. We measure the relative impact of weather using degree-days. A degree-day is the measure of the variation in the weather based on the extent to which the average daily temperature falls above or below 65 degrees Fahrenheit. Each degree of temperature below 65 degrees Fahrenheit is counted as one heating degree-day, and each degree of temperature above 65 degrees Fahrenheit is counted as one cooling degree-day. Normal heating and cooling degree-days are based on the most recent 10-year average. Competition Natural Gas Distribution While our natural gas distribution operations do not compete directly with other distributors of natural gas for residential and commercial customers in our service areas, we do compete with other natural gas suppliers and alternative fuel providers for sales to industrial customers. Large customers could bypass our natural gas distribution systems and connect directly to intrastate or interstate transmission pipelines, and we compete in all aspects of our natural gas business with alternative energy sources, including electricity, oil, propane and renewables. The most effective means to compete against alternative fuels are lower prices, superior reliability and flexibility of service. Natural gas historically has maintained a price advantage in the residential, commercial and industrial markets, and reliability of natural gas supply and service has been excellent. In addition, we provide flexible pricing to our large customers to minimize fuel switching and protect these volumes and their contributions to the profitability of our natural gas distribution operations. Natural Gas Transmission Our natural gas transmission business competes with other interstate and intrastate pipeline companies to provide service to large industrial, generation and distribution customers, primarily in the northern portion of the Delmarva Peninsula and in Florida. Our transmission business in Ohio, Aspire Energy Express, services one customer, Guernsey Power Station, to which it is the sole supplier. Electric Distribution While our electric distribution operations do not compete directly with other distributors of electricity for residential and commercial customers in our service areas, we do compete with other electricity suppliers and alternative fuel providers for sales to industrial customers. Some of our large industrial customers may be capable of generating their own electricity, and we structure rates, service offerings and flexibility to retain these customers in order to retain their business and contributions to the profitability of our electric distribution operations. Chesapeake Utilities Corporation 2022 Form 10-K Page 7 Supplies, Transmission and Storage Natural Gas Distribution Our natural gas distribution operations purchase natural gas from marketers and producers and maintain contracts for transportation and storage with several interstate pipeline companies to meet projected customer demand requirements. We believe that our supply and capacity strategy will adequately meet our customers needs over the next several years and we will continue to adapt our supply strategy to meet projected growth in customer demand within our service territories. The

Ticker: CPK, Sector: Utilities, Filed At: 2023-02-22T17:10:26-05:00

Delmarva natural gas distribution systems are directly connected to Eastern Shores pipeline, which has connections to other pipelines that provide us with transportation and storage. These operations can also use propane-air and liquefied natural gas peak-shaving equipment to serve customers. Our Delmarva Peninsula natural gas distribution operations maintain asset management agreements with a third party to manage their natural gas transportation and storage capacity. The agreements were effective as of April 1, 2020 and currently expire on March 31, 2023. Our Delmarva operations receive a fee, which we share with our customers, from the asset manager, who optimizes the transportation, storage and natural gas supply for these operations. Our Florida natural gas distribution operation uses Peninsula Pipeline and Peoples Gas to transport natural gas where there is no direct connection with FGT. FPU natural gas distribution and Eight Flags entered into separate 10-year asset management agreements with Emera Energy Services, Inc. to manage their natural gas transportation capacity, each of which expires in November 2030. An agreement with Florida Southeast Connection LLC for additional service to Palm Beach County is also in place for an initial term through December 2044. A summary of our pipeline capacity contracts follows: ##TABLE_START Maximum Daily Firm Transportation Capacity (Dts) Contract Expiration Date Division Pipeline Delmarva Natural Gas Distribution Eastern Shore 154,379 2023-2035 Columbia Gas (1) 5,246 2023-2024 Transco (1) 30,419 2023-2028 TETLP (1) 50,000 2027 Florida Natural Gas Distribution Gulfstream (2) 10,000 2032 FGT 47,409 - 78,817 2025-2041 Peninsula Pipeline 337,200 2033-2048 Peoples Gas 12,160 2024 Florida Southeast Connection LLC 5,000 2044 Southern Natural Gas Company 1,500 2029 ##TABLE_END(1) Transco, Columbia Gas and TETLP are interstate pipelines interconnected with Eastern Shore's pipeline (2) Pursuant to a capacity release program approved by the Florida PSC, all of the capacity under this agreement has been released to various third parties. Under the terms of these capacity release agreements, Chesapeake Utilities is contingently liable to Gulfstream should any party, that acquired the capacity through release, fail to pay the capacity charge. Eastern Shore has three agreements with Transco for a total of 7,292 Dts/d of firm daily storage injection and withdrawal entitlements and total storage capacity of 288,003 Dts. These agreements expire in March 2028. Eastern Shore retains these firm storage services in order to provide swing transportation service and firm storage service to customers requesting such services. Aspire Energy Express, our Ohio intrastate pipeline subsidiary, entered into a precedent agreement to provide natural gas transportation capacity to Guernsey Power Station, who has completed construction of its power generation facility in Guernsey County Ohio in January 2023. Aspire Energy Express completed construction of the gas transmission facilities in the fourth quarter of 2021 and began billing for transportation services in the first quarter of 2022. Chesapeake Utilities Corporation 2022 Form 10-K Page 8 Electric Distribution Our Florida electric distribution operation purchases wholesale electricity under the power supply contracts summarized below: ##TABLE_START Area Served by Contract Counterparty Contracted Amount (MW) Contract Expiration Date Northwest Florida Gulf

Ticker: CPK, Sector: Utilities, Filed At: 2023-02-22T17:10:26-05:00

Power Company Full Requirement* 2026 Northeast Florida Florida Power Light Company Full Requirement* 2026 Northeast Florida Eight Flags 21 2036 Northeast Florida Rayonier 1.7 to 3.0 2036 Northeast Florida WestRock Company As-available N/A ##TABLE_END*The counter party is obligated to provide us with the electricity to meet our customers demand, which may vary. Unregulated Energy Overview The following table presents net income for the year ended December 31, 2022 and total assets as of December 31, 2022, for our Unregulated Energy segment by operation and area served: ##TABLE_START Operations Area Served Net Income (Loss) Total Assets (in thousands) Propane Operations (Sharp, Diversified Energy, FPU and Flo-gas) Delaware, Maryland, Virginia, Pennsylvania, North Carolina, South Carolina, Florida $ 13,791 $ 190,298 Energy Transmission (Aspire Energy) Ohio 2,610 147,068 Energy Generation (Eight Flags) Florida 1,817 36,945 Marlin Gas Services The Entire U.S. 716 60,805 Renewable Energy Investments Delaware, Maryland, Florida (729) 27,450 Total $ 18,205 $ 462,566 ##TABLE_ENDPropane Operations Our propane operations sell propane to residential, commercial/industrial, wholesale and AutoGas customers, in the Mid-Atlantic region, North Carolina, South Carolina and Florida, through Sharp Energy, Inc., Sharpgas, Inc., Diversified Energy, FPU and Flo-gas. We deliver to and bill our propane customers based on two primary customer types: bulk delivery customers and metered customers. Bulk delivery customers receive deliveries into tanks at their location. We invoice and record revenues for these customers at the time of delivery. Metered customers are either part of an underground propane distribution system or have a meter installed on the tank at their location. We invoice and recognize revenue for these customers based on their consumption as dictated by scheduled meter reads. As a member of AutoGas Alliance, we install and support propane vehicle conversion systems for vehicle fleets and provide on-site fueling infrastructure. Chesapeake Utilities Corporation 2022 Form 10-K Page 9 Propane Operations - Operational Highlights For the year ended December 31, 2022, operating revenues, volumes sold and average number of customers by customer class for our propane operations were as follows: ##TABLE_START Operating Revenues (in thousands) (2) Volumes (in thousands of gallons) (2) Average Number of Customers (1)(2) Residential bulk $ 54,439 29 % 17,556 22 % 58,320 71 % Residential metered 18,300 10 % 5,491 7 % 16,072 19 % Commercial bulk 49,922 27 % 24,543 30 % 8,050 10 % Commercial metered 1,916 1 % 586 1 % 210 1% Wholesale 36,609 19 % 27,825 34 % 47 1% AutoGas 7,524 4 % 4,544 6 % 128 1% Other (3) 19,702 10 % % % Total $ 188,412 100 % 80,545 100 % 82,827 100 % ##TABLE_END(1) Average number of customers is based on a twelve-month average for the year ended December 31, 2022. (2) Operating revenues, volumes and average customer includes those for Diversified Energy that was acquired in December 2021. See Item 8, Financial Statements and Supplementary Data (Note 4, Acquisitions in the consolidated financial statements) for further information. (3) Operating revenues from "Other" sources include revenues from customer loyalty programs; delivery, service and appliance fees; and unbilled revenues. Competition Our propane operations compete with national and local independent companies primarily on the basis of price and service. Propane is generally a cheaper fuel for home heating than oil and electricity but more expensive than natural gas. Our propane operations are largely concentrated in areas that are not currently served by natural gas distribution systems. Supplies, Transportation and Storage We purchase propane from major oil companies and independent natural gas liquids producers. Propane is transported by truck and rail to our bulk storage facilities in Pennsylvania, Delaware, Maryland, Virginia, North Carolina, South Carolina and Florida which have a total storage capacity of 8.7 million gallons. Deliveries are made from these facilities by truck to tanks located on customers premises or to central storage tanks that feed our underground propane distribution systems. While propane supply has traditionally been adequate, significant fluctuations in weather, closing of refineries and disruption in supply chains, could cause temporary reductions in available supplies. Weather Propane revenues are affected by seasonal variations in temperature and weather conditions, which directly influence the volume of propane used by our customers. Our propane revenues are typically highest during the winter months when propane is used for heating. Sustained warmer-than-normal temperatures will tend to reduce propane use, while sustained colder-than-normal temperatures will tend to increase consumption. Unregulated Energy Transmission and Supply (Aspire Energy) Aspire Energy owns approximately 2,800 miles of natural gas pipeline systems in 40 counties in Ohio. The majority of Aspire Energys revenues are derived from long-term supply agreements with Columbia Gas of Ohio and Consumers Gas Cooperative ("CGC"), which together serve more than 22,000 end-use customers. Aspire Energy purchases natural gas to serve these customers from conventional producers in the Marcellus and Utica natural gas production areas. In October 2021, Aspire Energy completed construction of its Noble Road Landfill RNG pipeline project, which began transporting RNG generated from the landfill to Aspire Energys pipeline system in January of 2022, displacing conventionally produced natural gas. The RNG volume is estimated to represent nearly 10 percent of Aspire Energys gas gathering volumes in the future. In addition, Aspire Energy earns revenue by gathering and processing natural gas for customers. Chesapeake Utilities Corporation 2022 Form 10-K Page 10 For the twelve-month period ended December 31, 2022, Aspire Energy's operating revenues and deliveries by customer type were as follows: ##TABLE_START Operating revenues Deliveries (in thousands) % of Total (in thousands Dts) % of Total Supply to Columbia Gas of Ohio $ 20,812 37 % 2,543 40 % Supply to CGC 20,748 37 % 1,914 30 % Supply to Marketers - unaffiliated 11,833 21 % 1,864 29 % Other (including natural gas gathering and processing) 2,832 5 % 82 1 % Total $ 56,225 100 % 6,403 100 % ##TABLE_ENDEnergy Generation (Eight Flags) Eight Flags generates electricity and steam at its CHP plant located on Amelia Island, Florida. The plant is powered by natural gas transported by Peninsula Pipeline and our Florida natural gas distribution operation and produces approximately 21 MW of electricity and 75,000 pounds per hour of steam. Eight Flags sells the electricity generated from the plant to our Florida electric distribution operation and sells the steam to the customer who owns the site on which the plant is located both under separate 20-year contracts. Marlin Gas Services Marlin Gas Services is a supplier of mobile CNG and virtual pipeline solutions, primarily to utilities and pipelines. Marlin Gas Services provides temporary hold services, pipeline integrity services, emergency services for damaged pipelines and specialized gas services for customers who have unique requirements. These services are provided by a highly trained staff of drivers and maintenance technicians who safely perform these functions throughout the United States. Marlin Gas Services maintains a fleet of CNG trailers, mobile compression equipment, LNG tankers and vaporizers, and an internally developed patented regulator system which allows for delivery of over 7,000 Dts/d of natural gas. Marlin Gas Services continues to actively expand the territories it serves, as well as leveraging its fleet of equipment and patented technologies to serve LNG and RNG market needs. Renewable Energy Investments Our renewable energy investments are comprised primarily of our sustainable energy initiatives that are in various stages of development. Included in these are the assets and intellectual property of Planet Found that we acquired during the fourth quarter of 2022, whose farm scale anaerobic digestion pilot system and technology produces biogas from poultry litter which can be used to create renewable energy in the form of electricity or upgraded to renewable natural gas. Environmental Matters See Item 8, Financial Statements and Supplementary Data (see Note 19 , Environmental Commitments and Contingencies, in the consolidated financial statements). Human Capital Initiatives Our success is the direct result of our employees and our strong culture that fully engages our team and promotes equity, diversity, inclusion, integrity, accountability and reliability. We believe that a combination of diverse team members and an inclusive culture contributes to the success of our Company and to enhanced societal advancement. Each employee is a valued member of our team bringing a diverse perspective to help grow our business and achieve our goals. Our tradition of serving employees, customers, investors, partners and communities is at the core of our culture. Among the ongoing initiatives across our enterprise, we highlight below the importance of our team, our culture of safety, and our environmental, social and governance stewardship. Our Team Drives Our Performance Our employees are the key to our success. Our leadership and human resources teams are responsible for attracting and retaining top talent.Our senior management team includes a Chief Human Resources Officer, with expertise in diverse candidate recruitment, to ensure that we continue to expand our candidate pools to better reflect the diverse demographics of the communities we serve. Furthermore, during 2022, we appointed a Chief Diversity Officer who has direct oversight for the Chesapeake Utilities Corporation 2022 Form 10-K Page 11 Company's equity, diversity and inclusion ("EDI") strategy and collaborates across the organization with the teams responsible for the enterprise-wide ESG plan. Throughout our organization, we seek to promote from within, reviewing strategic positions regularly and identifying potential internal candidates to fill those positions, evaluating critical job skill sets to identify competency gaps and creating developmental plans to facilitate employee professional growth. We provide training and development programs as well as tuition reimbursement to promote continued professional growth. As of December 31, 2022, we had a total of 1,034 employees, 105 of whom are union employees represented by two labor unions: the International Brotherhood of Electrical Workers and the United Food and Commercial Workers Union. The collective bargaining agreements with these labor unions expire in 2025. We consider our relationships with employees, including those covered by collective bargaining agreements, to be in good standing. We provide a competitive Total Rewards package for our employees including health insurance coverage, wellness initiatives, retirement savings benefits, paid time off, employee assistance programs, educational and tuition reimbursement, competitive pay, career growth oppo rtunities, paid volunteer time, and a culture of recognition. In 2023, the Company was recognized as a Top Workplaces USA award recipient among mid-sized companies for the third consecutive year. This follows being named a Top Workplace in Delaware for the tenth consecutive year in 2021, and being named a Top Workplace in Central Florida in 2019 and 2021. These honors were based entirely on feedback from employees who were surveyed by the research firm Energage. These recognitions are a testament to our employees commitment to excellence. Our employees are the backbone of our continued growth and success. We have an established EDI Council which recommends and promotes our EDI strategy, advises our employee resource groups (ERGs) and works with our operating units and support teams on EDI initiatives. The EDI Councils charter includes the following objectives: Build a more diverse and inclusive workforce Promote a culture of understanding, equality and inclusion Educate employees about the benefits of diversity at Chesapeake Utilities Support community programs and organizations that are diverse and inclusive Provide guidance on EDI matters for the Company The Chesapeake Utilities EDI Council includes members of our leadership team, the chairs of each of our ERGs and other individuals in key support roles. The CEO receives a regular report on the achievements of the EDI Council, strategic direction of initiatives, resource needs and issues that require policy decisions or other actions. Our first ERG was established in 2019, and at December 31, 2022, there were eight active ERGs meeting throughout the Company. ERGs are voluntary, employee-led groups that focus on shared identities, affinities and experiences and seek to apply those perspectives to initiatives that create value throughout the Company. The ERGs support the members' personal growth and professional development, and help develop learning programs and community service opportunities throughout the Company. ERGs also help foster a sense of belonging by creating a deep and intentional community that extends beyond an employees day-to-day team and colleagues into a companywide network. Workplace Health and Safety We believe that there is nothing more important than the safety of our team, our customers and our communities. We are committed to ensuring safety is at the center of our culture and the way we do business. The importance of safety is exhibited throughout the entire organization, with the direction and tone set by both our Board and our President and CEO, and evidenced through required attendance at monthly safety meetings, routine safety training and the inclusion of safety moments at key team meetings. Additionally, while most restrictions related to the COVID-19 pandemic have been lifted in the United States, we remain committed to providing products and services to our customers in a safe and reliable manner, and will continue to do so in compliance with any mandated restrictions in each of the markets we serve. To maintain safety as a priority, our employees remain committed and work together to ensure that our plans, programs, policies and behaviors are aligned with our aspirations as a Company. The achievement of superior safety performance is both an important short-term and long-term strategic initiative in managing our operations. In November 2020, we announced the completion of our state-of-the art training facility in Dover, Delaware. Safety Town now serves as a resource for training our employees who build, maintain and operate our natural gas infrastructure, offering hands-on training and fully immersive, on-the-job field experiences. First responders and other community partners also benefit from the simulated Chesapeake Utilities Corporation 2022 Form 10-K Page 12 environment and conditions they could encounter as they enter homes in the community. We are excited to start construction of a second Safety Town facility in Florida in 2023. Environmental, Social and Governance Stewardship Consistent with our culture of teamwork, the broad responsibility of ESG stewardship is supported across our organization by the dedication and efforts of our Board of Directors and its Committees, as well as the entrepreneurship and dedication of our team. As stewards of long-term enterprise value, the Board of Directors is committed to overseeing the sustainability of the Company its environmental stewardship initiatives, its safety and operational compliance practices, and to promoting equity, diversity and inclusion that reflects the diverse communities we serve. In 2022, Chesapeake Utilities established its ESG Committee, which brings together a cross-functional team of leaders across the organization responsible for identifying, assessing, executing and advancing the Company's strategic ESG initiatives. Additionally, we developed an Environmental Sustainability Office in 2022, which identifies and manages emission-reducing projects both internally, as well as those that support our customers' sustainability goals. Throughout the year, Chesapeake Utilities drove numerous initiatives to enhance its ESG program: Environmental: Successfully completed pilot test of hydrogen and natural gas blend to fuel the Companys Eight Flags CHP facility Opened the Companys first CNG fueling station near the Port of Savannah, capable of distributing RNG for fleet vehicles Acquired Planet Found Energy Development, a farm-scale anaerobic digestion system producing biogas from poultry waste which can be converted to renewable natural gas Social: Appointed a Chief Diversity Officer Provided donations to multiple charitable organizations aiding in the recovery efforts across Florida following Hurricane Ian, one of the strongest and most devastating storms to hit the state Unveiled Chesapeake Wellness, a free, digital service provided to all employees which includes key resources for building and sustaining healthy physical, mental and financial habits Governance: Increased transparency with the enhancement of our director skills matrix in the 2022 Proxy Statement Appointed Stephanie N. Gary and Sheree M. Petrone to serve as members of the Company's Board of Directors Recognized with "Best Corporate Governance in the U.S. for 2022" by World Finance magazine Chesapeake Utilities Corporation 2022 Form 10-K Page 13 Information About Executive Officers Set forth below are the names, ages, and positions of our executive officers with their recent business experience. The age of each officer is as of the filing date of this Annual Report. ##TABLE_START Name Age Executive Officer Since Offices Held During the Past Five Years Jeffry M. Householder 65 2010 President (January 2019 - present) Chief Executive Officer (January 2019 - present) Director (January 2019 - present) President of FPU (June 2010 - February 2019) Beth W. Cooper 56 2005 Executive Vice President (February 2019 - present) Chief Financial Officer (September 2008 - present) Senior Vice President (September 2008 - February 2019) Treasurer (January 2022 - present) Assistant Corporate Secretary (March 2015 - present) James F. Moriarty 65 2015 Executive Vice President (February 2019 - present) General Counsel Corporate Secretary (March 2015 - present) Chief Policy and Risk Officer (February 2019 - present) Senior Vice President (February 2017 - February 2019) Vice President (March 2015 - February 2017) Kevin J. Webber 64 2010 Chief Development Officer (January 2022 - present) Senior Vice President (February 2019 - present) President FPU (February 2019 - December 2019) Vice President Gas Operations and Business Development Florida Business Units (July 2010 - February 2019) Jeffrey S. Sylvester 53 2019 Chief Operating Officer (January 2022 - present) Senior Vice President (December 2019 - present) Vice President Black Hills Energy (October 2012 - December 2019) ##TABLE_ENDAvailable Information on Corporate Governance Documents Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports and amendments to these reports that we file with or furnish to the SEC at their website, www.sec.gov , are also available free of charge at our website, www.chpk.com , as soon as reasonably practicable after we electronically file these reports with, or furnish these reports to the SEC. The content of this website is not part of this Annual Report. In addition, the following documents are available free of charge on our website, www.chpk.com : Business Code of Ethics and Conduct applicable to all employees, officers and directors; Code of Ethics for Financial Officers; Corporate Governance Guidelines; and Charters for the Audit Committee, Compensation Committee, Investment Committee, and Corporate Governance Committee of the Board of Directors. Any of these reports or documents may also be obtained by writing to: Corporate Secretary; c/o Chesapeake Utilities Corporation, 500 Energy Lane Suite 100, Dover, DE 19901. I TEM 1A. R ISK F ACTORS The risks described below fall into three broad categories related to (1) financial risks, (2) operational risks, and (3) regulatory, legal and environmental risks, all of which may affect our operations and/or the financial performance of our regulated and unregulated energy businesses. These are not the only risks we face but are considered to be the most material. There may be other unknown or unpredictable risks or other factors that could have material adverse effects on our future results. Refer to the section entitled Item 7, Managements Discussion and Analysis of Financial Condition and Results of

Operations of this Annual Report for an additional discussion of these and other related factors that affect our operations and/or financial performance. Chesapeake Utilities Corporation 2022 Form 10-K Page 14 F INANCIAL R ISKS Instability and volatility in the financial markets could negatively impact access to capital at competitive rates, which could affect our ability to implement our strategic plan, undertake improvements and make other investments required for our future growth. Our business strategy includes the continued pursuit of growth and requires capital investment in excess of cash flow from operations. As a result, the successful execution of our strategy is dependent upon access to equity and debt at reasonable costs. Our ability to issue new debt and equity capital and the cost of equity and debt are greatly affected by our financial performance and the conditions of the financial markets. In addition, our ability to obtain adequate and cost-effective debt depends on our credit ratings. A downgrade in our current credit ratings could negatively impact our access to and cost of debt. If we are not able to access capital at competitive rates, our ability to implement our strategic plan, undertake improvements and make other investments required for our future growth may be limited. Fluctuations in propane gas prices could negatively affect results of operations. The combination of high demand and lower-than-average inventory is always a common driver for higher propane gas prices. We adjust the price of the propane we sell based on changes in our cost of purchasing propane. However, if the market does not allow us to increase propane sales prices to compensate fully for fluctuations in purchased propane costs, our results of operations and cash flows could be negatively affected. If we fail to comply with our debt covenant obligations, we could experience adverse financial consequences that could affect our liquidity and ability to borrow funds. Our long-term debt obligations and our Revolver contain financial covenants related to debt-to-capital ratios and interest-coverage ratios. Failure to comply with any of these covenants could result in an event of default which, if not cured or waived, could result in the acceleration of outstanding debt obligations or the inability to borrow under certain credit agreements. Any such acceleration could cause a material adverse change in our financial condition. As of December 31, 2022, we were in compliance with all of our debt covenants. Increases in interest rates may adversely affect our results of operations and cash flows. Increases in interest rates could increase the cost of future debt issuances. To the extent we are not able to fully recover higher debt costs in the rates we charge our utility customers, or the timing of such recovery is not certain, our earnings could be adversely affected. Increases in short-term interest rates could negatively affect our results of operations, which depend on short-term debt to finance accounts receivable and storage gas inventories and to temporarily finance capital expenditures. Reference should be made to Item 7A, Quantitative and Qualitative Disclosures about Market Risk for additional information. Continuing or worsening inflationary and/or supply chain issues may adversely impact our financial condition and results of operations. Our business is dependent on the supply chain to ensure that equipment, materials and other resources are available to both expand and maintain our services in a safe and reliable manner. Pricing of equipment, materials and other resources have increased recently and may continue to do so in the future. Failure to secure equipment, materials and other resources on economically acceptable terms, including failure to eliminate or manage the constraints in the supply chain, may impact the availability of items that are necessary to support normal operations as well as materials that are required for continued infrastructure growth, and as result, may adversely impact our financial condition and results of operations. In addition, it may become more costly for us to recruit and retain key employees, particularly specialized/technical personnel, in the face of competitive market conditions and increased competition for specialized and experienced workers in our industry. Disruptions, uncertainty or volatility in the credit and capital markets may exert downward pressure on the market price of the Companys common stock. The market price and trading volume of the Companys common stock is subject to fluctuations as a result of, among other factors, general credit and capital market conditions and changes in market sentiment regarding the operations, business and financing strategies of the Company and its subsidiaries. As a result, disruptions, uncertainty or volatility in the credit and capital markets may, amongst other things, have a material adverse effect on the market price of the Companys common stock. Current market conditions could adversely impact the return on plan assets for FPU's pension plan, which may require significant additional funding. In 2021, the Company terminated the Chesapeake Utilities pension plan. The FPU pension plan is closed to new employees, and the future benefits are frozen. The costs of providing benefits and related funding requirements of the FPU plan is subject to changes in the market value of the assets that fund the plan and the discount rates used to estimate the pension benefit obligations. The funded status of the plans and the related costs reflected in our financial statements are affected by various factors that are subject to an inherent degree of uncertainty, particularly in the current economic environment. Future losses of asset values and further declines in discount rates may necessitate accelerated funding of the plans to meet minimum federal government requirements and may result in higher pension expense in future years. Adverse changes in the benefit obligations of the FPU pension plan may require us to record higher pension expense and fund obligations earlier than originally planned, which would have an adverse impact on our cash flows from operations, decrease borrowing capacity and increase interest expense. O PERATIONAL R ISKS We are dependent upon construction of new facilities to support future growth in earnings in our natural gas and electric distribution and natural gas transmission operations. Construction of new facilities required to support future growth is subject to various regulatory and developmental risks, including but not limited to: (i) our ability to obtain timely certificate authorizations, necessary approvals and permits from regulatory agencies and on terms that are acceptable to us; (ii) potential changes in federal, state and local statutes and regulations, including environmental requirements, that prevent a project from proceeding or increase the anticipated cost of the project; (iii) our inability to acquire rights-of-way or land rights on a timely basis on terms that are acceptable to us; (iv) lack of anticipated future growth in available natural gas and electricity supply; (v) insufficient customer throughput commitments; and (vi) lack of available and qualified third-party contractors which could impact the timely construction of new facilities. We do not own all of the land on which our pipelines and facilities are located, which could result in disruptions to our operations. Because we do not own all of the land on which our pipelines and facilities have been constructed, we are subject to the possibility of more onerous terms or increased costs to retain necessary land use if we do not have valid rights-of-way or if such rights-of-way lapse or terminate. We obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies for a specific period of time. Our loss of these rights, through our inability to renew right-of-way contracts or otherwise, could have a material adverse effect on our business, financial condition and results of operations We operate in a competitive environment, and we may lose customers to competitors. Natural Gas . Our natural gas transmission and distribution operations compete with interstate pipelines when our customers are located close enough to a competing pipeline to make direct connections economically feasible. Customers also have the option to switch to alternative fuels, including renewable energy sources. Failure to retain and grow our natural gas customer base would have an adverse effect on our financial condition, cash flows and results of operations. Electric . Our Florida electric distribution business has remained substantially free from direct competition from other electric service providers but does face competition from other energy sources. Changes in the competitive environment caused by legislation, regulation, market conditions, or initiatives of other electric power providers, particularly with respect to retail electric competition, could adversely affect our results of operations, cash flows and financial condition. Propane . Our propane operations compete with other propane distributors, primarily on the basis of service and price. Our ability to grow the propane operations business is contingent upon capturing additional market share, expanding into new markets, and successfully utilizing pricing programs that retain and grow our customer base. Failure to retain and grow our customer base in our propane operations would have an adverse effect on our results of operations, cash flows and financial condition. Fluctuations in weather may cause a significant variance in our earnings. Our natural gas distribution, propane operations and natural gas transmission operations, are sensitive to fluctuations in weather conditions, which directly influence the volume of natural gas and propane we transport, sell and deliver to our Chesapeake Utilities Corporation 2022 Form 10-K Page 16 customers. A significant portion of our natural gas distribution, propane operations and natural gas transmission revenue is derived from the sales and deliveries to residential, commercial and industrial heating customers during the five-month peak heating season (November through March). Other than our Maryland natural gas distribution businesses (Maryland division, Sandpiper Energy and Elkton Gas) which have revenue normalization mechanisms, if the weather is warmer than normal, we sell and deliver less natural gas and propane to customers, and earn less revenue, which could adversely affect our results of operations, cash flows and financial condition. Conversely, if the weather is colder than normal, we sell and deliver more natural gas and propane to customers, and earn more revenue, which could positively affect our results of operations, cash flows and financial condition. Variations in weather from year to year can cause our results of operations, cash flows and financial condition to vary accordingly. Our electric distribution operation is also affected by variations in weather conditions and unusually severe weather conditions. However, electricity consumption is generally less seasonal than natural gas and propane because it is used for both heating and cooling in our service areas. Natural disasters, severe weather events (such as a major hurricane) and acts of terrorism could adversely impact earnings and access to insurance coverage. Inherent in energy transmission and distribution activities are a variety of hazards and operational risks, such as leaks, ruptures, fires, uncontrollable flows of natural gas, explosions, release of contaminants into the environment, sabotage and mechanical problems. Natural disasters and severe weather events may damage our assets, cause operational interruptions and result in the loss of human life, all of which could negatively affect our earnings, financial condition and results of operations. Acts of terrorism and the impact of retaliatory military and other action by the United States and its allies may lead to increased political, economic and financial market instability and volatility in the price of natural gas, electricity and propane that could negatively affect our operations. Companies in the energy industry may face a heightened risk of exposure to acts of terrorism, which could affect our results of operations, cash flows and financial condition. The insurance industry may also be affected by natural disasters, severe weather events and acts of terrorism. As a result, the availability of insurance covering risks against which we and our competitors typically insure may be limited. In addition, the insurance we are able to obtain may have higher deductibles, higher premiums and more restrictive policy terms, which could adversely affect our results of operations, financial condition and cash flows. Operating events affecting public safety and the reliability of our natural gas and electric distribution and transmission systems could adversely affect our operations and increase our costs. Our natural gas and electric operations are exposed to operational events and risks, such as major leaks, outages, mechanical failures and breakdown, operations below the expected level of performance or efficiency, and accidents that could affect public safety and the reliability of our distribution and transmission systems, significantly increase costs and cause loss of customer confidence. If we are unable to recover all or some of these costs from insurance and/or customers through the regulatory process, our results of operations, financial condition and cash flows could be adversely affected. A security breach disrupting our operating systems and facilities or exposing confidential information may adversely affect our reputation, disrupt our operations and increase our costs. The cybersecurity risks associated with the protection of our infrastructure and facilities is evolving and increasingly complex. We continue to heavily rely on technological tools that support our business operations and corporate functions while enhancing our security. There are various risks associated with our information technology infrastructure, including hardware and software failure, communications failure, data distortion or destruction, unauthorized access to data, misuse of proprietary or confidential data, unauthorized control through electronic means, cyber-attacks, cyber-terrorism, data breaches, programming mistakes, and other inadvertent errors or deliberate human acts. Further, the U.S. government has issued public warnings that indicate energy assets might be specific targets of cybersecurity threats and/or attacks. Many of our employees, service providers, and vendors have been working, and may continue to work, from remote locations, where cybersecurity protections may be limited and cybersecurity procedures and safeguards may be less effective. As such, we may be subject to a higher risk of cybersecurity breaches than ever before. Therefore, we may be required to expend significant resources to continue to modify or enhance our procedures and controls or to upgrade our digital and operational systems, related infrastructure, technologies and network security. Any such failure, attack, or security breach could adversely impact our ability to safely and reliably deliver services to our customers through our transmission, distribution, and generation systems, subject to us to reputational and other harm, and subject us to legal and regulatory proceedings and claims and demands from third parties, any of which could adversely affect Chesapeake Utilities Corporation 2022 Form 10-K Page 17 our business, our earnings, results of operation and financial condition. In addition, the protection of customer, employee and Company data is crucial to our operational security. A breach or breakdown of our systems that results in the unauthorized release of individually identifiable customer or other sensitive data could have an adverse effect on our reputation, results of operations and financial condition and could also materially increase our costs of maintaining our system and protecting it against future breakdowns or breaches. We take reasonable precautions to safeguard our information systems from cyber-attacks and security breaches; however, there is no guarantee that the procedures implemented to protect against unauthorized access to our information systems are adequate to safeguard against all attacks and breaches. We also cannot assure that any redundancies built into our networks and technology, or the procedures we have implemented to protect against cyber-attacks and other unauthorized access to secured data, are adequate to safeguard against all failures of technology or security breaches. Failure to attract and retain an appropriately qualified employee workforce could adversely affect operations. Our ability to implement our business strategy and serve our customers depends upon our continuing ability to attract, develop and retain talented professionals and a technically skilled workforce in a manner competitive with current market conditions, and transfer the knowledge and expertise of our workforce to new employees as our existing employees retire. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to new employees, or the future availability and cost of contract labor could adversely affect our ability to manage and operate our business. If we were unable to hire, train and retain appropriately qualified personnel, our results of operations could be adversely affected. A strike, work stoppage or a labor dispute could adversely affect our operations. We are party to collective bargaining agreements with labor unions at some of our Florida operations. A strike, work stoppage or a labor dispute with a union or employees represented by a union could cause interruption to our operations and our results could be adversely affected. Our businesses are capital-intensive, and the increased costs and/or delays of capital projects may adversely affect our future earnings. Our businesses are capital-intensive and require significant investments in ongoing infrastructure projects. Our ability to complete our infrastructure projects on a timely basis and manage the overall cost of those projects may be affected by the availability of the necessary materials and qualified vendors. Our future earnings could be adversely affected if we are unable to manage such capital projects effectively, or if full recovery of such capital costs is not permitted in future regulatory proceedings. Our regulated energy business may be at risk if franchise agreements are not renewed, or new franchise agreements are not obtained, which could adversely affect our future results or operating cash flows and financial condition. Our regulated natural gas and electric distribution operations hold franchises in each of the incorporated municipalities that require franchise agreements in order to provide natural gas and electricity. Ongoing financial results would be adversely impacted in the event that franchise agreements were not renewed. If we are unable to obtain franchise agreements for new service areas, growth in our future earnings could be negatively impacted. Slowdowns in customer growth may adversely affect earnings and cash flows. Our ability to increase revenues in our natural gas, propane and electric distribution businesses is dependent upon growth in the residential construction market, adding new commercial and industrial customers and conversion of customers to natural gas, electricity or propane from other energy sources. Slowdowns in growth may adversely affect our results of operations, cash flows and financial condition. Chesapeake Utilities Corporation 2022 Form 10-K Page 18 Energy conservation, including the effects of environmental, social, and governance (ESG) initiatives could lower energy consumption, which would adversely affect our earnings. Federal and state legislative and regulatory initiatives to promote energy efficiency, conservation and the use of alternative energy sources could lower consumption of natural gas and propane by our customers. For example, on August 16, 2022, the Inflation Reduction Act of 2022 (IRA) was signed into law, with hundreds of billions of dollars in incentives for the development of renewable energy, clean hydrogen, and clean fuels, amongst other provisions. These incentives could further accelerate the transition of the U.S. economy away from the use of fossil fuels towards lower- or zero-carbon emissions alternatives and impact demand for our products and services. In addition, increasing attention to climate change, societal expectations on companies to address climate change, investor and societal expectations regarding voluntary ESG disclosures, and the aforementioned demand for alternative forms of energy, may result in increased costs and reduced demand for our products. While we cannot predict the ultimate effect that the development of alternative energy sources and related laws might have on our operations, we may be subject to reduced profits, increased investigations and litigation against us, and negative impacts on our stock price and access to capital markets. In addition, higher costs of natural gas, propane and electricity may cause customers to conserve fuel. To the extent a PSC or the FERC does not allow the recovery through customer rates of higher costs or lower consumption from energy efficiency or conservation, and our propane retail prices cannot be increased due to market conditions, our results of operations, cash flows and financial condition may be adversely affected. Commodity price increases may adversely affect the operating costs and competitive positions of our natural gas, electric and propane operations, which may adversely affect our results of operations, cash flows and financial condition. Natural Gas/Electricity . Higher natural gas prices can significantly increase the cost of gas billed to our natural gas customers. Increases in the cost of natural gas and other fuels used to generate electricity can significantly increase the cost of electricity billed to our electric customers. Damage to the production or transportation facilities of our suppliers, which decreases their supply of natural gas and electricity, could result in increased supply costs and higher prices for our customers. Such cost increases generally have no immediate effect on our revenues and net income because of our regulated fuel cost recovery mechanisms. However, our net income may be reduced by higher expenses that we may incur for uncollectible customer accounts and by lower volumes of natural gas and electricity deliveries when customers reduce their consumption. Therefore, increases in the price of natural gas and other fuels can adversely affect our operating cash flows, results of operations and financial condition, as well as the competitiveness of natural gas and electricity as energy sources. Propane . Propane costs are subject to changes as a result of product supply or other market conditions, including weather, economic and political factors affecting crude oil and natural gas supply or pricing. For example, weather conditions could damage production or transportation facilities, which could result in decreased supplies of propane, increased supply costs and higher prices for customers. Such increases in costs can occur rapidly and can negatively affect profitability. There is no assurance that we will be able to pass on propane cost increases fully or immediately, particularly when propane costs increase rapidly. Therefore, average retail sales prices can vary significantly from year-to-year as product costs fluctuate in response to propane, fuel oil, crude oil and natural gas commodity market conditions. In addition, in periods of sustained higher commodity prices, declines in retail sales volumes due to reduced consumption and increased amounts of uncollectible accounts may adversely affect net income. Refer to Item 7A , Quantitative and Qualitative Disclosures about Market Risk for additional information. Our use of derivative instruments may adversely affect our results of operations. Fluctuating commodity prices may affect our earnings and financing costs because our propane operations use derivative instruments, including forwards, futures, swaps, puts, and calls, to hedge price risk. While we have risk management policies and operating procedures in place to control our exposure to risk, if we purchase derivative instruments that are not properly matched to our exposure, our results of operations, cash flows, and financial condition may be adversely affected.

A substantial disruption or lack of growth in interstate natural gas pipeline transmission and storage capacity or electric transmission capacity may impair our ability to meet customers existing and future requirements. In order to meet existing and future customer demands for natural gas and electricity, we must acquire sufficient supplies of natural gas and electricity, interstate pipeline transmission and storage capacity, and electric transmission capacity to serve such requirements. We must contract for reliable and adequate upstream transmission capacity for our distribution systems while considering the dynamics of the interstate pipeline and storage and electric transmission markets, our own on-system resources, as well as the characteristics of our markets. Our financial condition and results of operations would be materially and adversely affected if the future availability of these capacities were insufficient to meet future customer demands for Chesapeake Utilities Corporation 2022 Form 10-K Page 19 natural gas and electricity. Currently, our Florida natural gas operation relies primarily on two pipeline systems, FGT and Peninsula Pipeline, our intrastate pipeline subsidiary for most of its natural gas supply and transmission. Our Florida electric operation secures electricity from external parties. Any continued interruption of service from these suppliers could adversely affect our ability to meet the demands of our customers, which could negatively impact our earnings, financial condition and results of operations. Our ability to grow our businesses could be adversely affected if we are not successful in making acquisitions or integrating the acquisitions we have completed. One of our strategies is to grow through acquisitions of complementary businesses. Acquisitions involve a number or risks including, but not limited to, the assumption of material liabilities, the diversion of managements attention from the management of daily operations to the integration of operations, difficulties in the assimilation and retention of employees and difficulties in the assimilation of different cultures and internal controls. Future acquisitions could also result in, among other things, the failure to identify material issues during due diligence, the risk of overpaying for assets, unanticipated capital expenditures, the failure to maintain effective internal control over financial reporting, recording goodwill and other intangible assets at values that ultimately may be subject to impairment charges and fluctuations in quarterly results. There can also be no assurance that our past and future acquisitions will deliver the strategic, financial and operational benefits that we anticipate. The failure to successfully integrate acquisitions could have an adverse effect on our results of operations, cash flows and financial condition. An impairment of our assets could result in a significant charge to earnings. In accordance with GAAP, goodwill, intangible, and other long-lived assets are tested for impairment annually or whenever events or changes in circumstances indicate impairment may have occurred. If the testing performed indicates that impairment has occurred, we are required to record an impairment charge for the difference between the carrying value of the applicable asset and the implied fair value in the period the determination is made. The testing of assets for impairment requires us to make significant estimates about our future performance and cash flows, as well as other assumptions. These estimates can be affected by numerous factors, including: future business operating performance, changes in economic conditions and interest rates, regulatory, industry or market conditions, changes in business operations, changes in competition or changes in technologies. Any changes in key assumptions, or actual performance compared with key assumptions, about our business and its future prospects could affect the fair value of one or more of our assets, which may result in an impairment charge. R EGULATORY, L EGAL AND E NVIRONMENTAL R ISKS Regulation of our businesses, including changes in the regulatory environment, may adversely affect our results of operations, cash flows and financial condition. The Delaware, Maryland, Ohio and Florida PSCs regulate our utility operations in those states. Eastern Shore is regulated by the FERC. The PSCs and the FERC set the rates that we can charge customers for services subject to their regulatory jurisdiction. Our ability to obtain timely rate increases and rate supplements to maintain current rates of return depends on regulatory approvals, and there can be no assurance that our regulated operations will be able to obtain such approvals or maintain currently authorized rates of return. When earnings from our regulated utilities exceed the authorized rate of return, the respective regulatory authority may require us to reduce our rates charged to customers in the future. We may face certain regulatory and financial risks related to pipeline safety legislation. We are subject to a number of legislative proposals at the federal and state level to implement increased oversight over natural gas pipeline operations and facilities to inspect pipeline facilities, upgrade pipeline facilities, or control the impact of a breach of such facilities. Additional operating expenses and capital expenditures may be necessary to remain in compliance. If new legislation is adopted and we incur additional expenses and expenditures, our financial condition, results of operations and cash flows could be adversely affected, particularly if we are not authorized through the regulatory process to recover from customers some or all of these costs and our authorized rate of return. Pipeline integrity programs and repairs may impose significant costs and liabilities on the Company. The U.S. Pipeline and Hazardous Materials Safety Administration (PHMSA) requires pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines and to take additional measures to protect pipeline segments located in areas where a leak or rupture could potentially do the most harm. PHMSA constantly updates its Chesapeake Utilities Corporation 2022 Form 10-K Page 20 regulations to ensure the highest levels of pipeline safety. As the operator of pipelines, we are required to: perform ongoing assessments of pipeline integrity; identify and characterize applicable threats to pipelines; improve data collection, integration and analysis; repair and remediate the pipelines as necessary; and implement preventative and mitigating actions. These new and any future regulations adopted by PHMSA may impose more stringent requirements applicable to integrity management programs and other pipeline safety aspects of our operations, which could cause us to incur increased capital and operating costs and operational delays. Moreover, should we fail to comply with the PHMSA rules and regulations, we could be subject to significant penalties and fines which may adversely affect our results of operations, cash flows and financial condition. We are subject to operating and litigation risks that may not be fully covered by insurance. Our operations are subject to the operating hazards and risks normally incidental to handling, storing, transporting, transmitting and delivering natural gas, electricity and propane to end users. From time to time, we are a defendant in legal proceedings arising in the ordinary course of business. We maintain insurance coverage for our general liabilities in the amount of $52 million, which we believe is reasonable and prudent. However, there can be no assurance that such insurance will be adequate to protect us from all material expenses related to potential future claims for personal injury and property damage or that such levels of insurance will be available in the future at economical prices. Costs of compliance with environmental laws may be significant. We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These evolving laws and regulations may require expenditures over a long period of time to control environmental effects at our current and former operating sites, especially former MGP sites. To date, we have been able to recover, through regulatory rate mechanisms, the costs associated with the remediation of former MGP sites. However, there is no guarantee that we will be able to recover future remediation costs in the same manner or at all. A change in our approved rate mechanisms for recovery of environmental remediation costs at former MGP sites could adversely affect our results of operations, cash flows and financial condition. Further, existing environmental laws and regulations may be revised, or new laws and regulations seeking to protect the environment may be adopted and be applicable to us. Revised or additional laws and regulations could result in additional operating restrictions on our facilities or increased compliance costs, which may not be fully recoverable. Any such increase in compliance costs could adversely affect our financial condition and results of operations. Compliance with these legal obligations requires us to commit capital. If we fail to comply with environmental laws and regulations, even if such failure is caused by factors beyond our control, we may be assessed administrative, civil, or criminal penalties and fines, imposed with investigatory and remedial obligations, or issued injunctions all of which could impact our financial condition and results of operations. See Item 8, Financial Statements and Supplementary Data (see Note 19 , Environmental Commitments and Contingencies, in the consolidated financial statements). Unanticipated changes in our tax provisions or exposure to additional tax liabilities could affect our profitability and cash flow. We are subject to income and other taxes in the U.S. and the states in which we operate. Changes in applicable state or U.S. tax laws and regulations, or their interpretation and application, including the possibility of retroactive effect, could affect our tax expense and profitability. In addition, the final determination of any tax audits or related litigation could be materially different from our historical income tax provisions and accruals. Changes in our tax provision or an increase in our tax liabilities, due to changes in applicable law and regulations, the interpretation or application thereof, future changes in the tax rate or a final determination of tax audits or litigation, could have a material adverse effect on our financial position, results of operations or cash flows. Our business may be subject in the future to additional regulatory and financial risks associated with global warming and climate change. There have been a number of federal and state legislative and regulatory initiatives proposed in recent years in an attempt to control or limit the effects of global warming and overall climate change, including greenhouse gas emissions, such as carbon dioxide. The direction of future U.S. climate change regulation is difficult to predict given the potential for policy changes under different Presidential administrations and Congressional leadership. The EPA may or may not continue developing regulations to reduce greenhouse gas emissions. Even if federal efforts in this area slow, states, cities and local jurisdictions may continue pursuing climate regulations. Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur additional operating costs, such as costs to purchase and operate emissions controls, to obtain emission allowances or to pay emission taxes, and reduce demand for our energy delivery services. Federal, state and local legislative initiatives to implement renewable portfolio standards or to further subsidize the cost of Chesapeake Utilities Corporation 2022 Form 10-K Page 21 solar, wind and other renewable power sources may change the demand for natural gas. We cannot predict the potential impact that such laws or regulations, if adopted, may have on our future business, financial condition or financial results. Climate changes may impact the demand for our services in the future and could result in more frequent and more severe weather events, which ultimately could adversely affect our financial results. Significant climatic change creates physical and financial risks for us. Our customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions may be affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of any changes. To the extent that climate change adversely impacts the economic health or weather conditions of our service territories directly, it could adversely impact customer demand or our customers ability to pay. Changes in energy use due to weather variations may affect our financial condition through volatility and/or decreased revenues and cash flows. Extreme weather conditions require more system backups and can increase costs and system stresses, including service interruptions. Severe weather impacts our operating territories primarily through thunderstorms, tornadoes, hurricanes, and snow or ice storms. Weather conditions outside of our operating territories could also have an impact on our revenues and cash flows by affecting natural gas prices. To the extent the frequency of extreme weather events increases, this could increase our costs of providing services. We may not be able to pass on the higher costs to our customers or recover all the costs related to mitigating these physical risks. To the extent financial markets view climate change and emissions of greenhouse gases as a financial risk, this could adversely affect our ability to access capital markets or cause us to receive less favorable terms and conditions in future financings. Our business could be affected by the potential for investigations and lawsuits related to or against greenhouse gas emitters based on the claimed connection between greenhouse gas emissions and climate change, which could impact adversely our business, results of operations and cash flows. We face risks associated with widespread public health crises, epidemics, or pandemics which may have material adverse impacts on the Company's operations, financial condition, liquidity and results of operations. The Company is subject to the impacts of widespread public health crises, epidemics and pandemics, including the recent COVID-19 outbreak. Such impacts may include, but are not limited to, effects on the national and local economy, capital and credit markets, the workforce, customers and suppliers. There is no assurance that the Companys businesses will be able to operate without material adverse impacts depending on the nature of the public health crisis, epidemic or pandemic. The ultimate severity, duration and impact of public health crises, epidemics and pandemics cannot be predicted. Additionally, there is no assurance that vaccines, or other treatments, are or will be widely available or effective, or that the public will be willing to participate, in an effort to contain the spread of disease. Actions taken in response to such crises by federal, state and local government or regulatory agencies may have a material adverse impact on the Companys business, financial condition, liquidity and results of operations. While most restrictions related to the COVID-19 pandemic have been lifted in the United States, we remain committed to providing products and services to our customers in a safe and reliable manner, and will continue to do so in compliance with any mandated restrictions in each of the markets we serve. Our certificate of incorporation and bylaws may delay or prevent a transaction that stockholders would view as favorable. Our certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could delay, defer or prevent an unsolicited change in control of Chesapeake Utilities, which may negatively affect the market price of our common stock or the ability of stockholders to participate in a transaction in which they might otherwise receive a premium for their shares over the then current market price. These provisions may also prevent changes in management. In addition, our Board of Directors is authorized to issue preferred stock without stockholder approval on such terms as our Board of Directors may determine. Our common stockholders will be subject to, and may be negatively affected by, the rights of any preferred stock that may be issued in the future.

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Ticker: CMS, Sector: Utilities, Filed At: 2023-02-09T09:11:10-05:00

Item 1. Business General CMS Energy CMS Energy was formed as a corporation in Michigan in 1987 and is an energy company operating primarily in Michigan. It is the parent holding company of several subsidiaries, including Consumers, an electric and gas utility, and NorthStar Clean Energy (formerly known as CMS Enterprises Company), primarily a domestic independent power producer and marketer. Consumers serves individuals and businesses operating in the alternative energy, automotive, chemical, food, and metal products industries, as well as a diversified group of other industries. NorthStar Clean Energy, through its subsidiaries and equity investments, is engaged in domestic independent power production, including the development and operation of renewable generation, and the marketing of independent power production. CMS Energy manages its businesses by the nature of services each provides, and operates principally in three business segments: electric utility; gas utility; and NorthStar Clean Energy, its nonutility operations and investments. Consumers consolidated operations account for the substantial majority of CMS Energys total assets, income, and operating revenue. CMS Energys consolidated operating revenue was $8.6 billion in 2022, $7.3 billion in 2021, and $6.4 billion in 2020. For further information about operating revenue, income, and assets and liabilities attributable to all of CMS Energys business segments and operations, see Item 8. Financial Statements and Supplementary DataCMS Energy Consolidated Financial Statements and Notes to the Consolidated Financial Statements. Consumers Consumers has served Michigan customers since 1886. Consumers was incorporated in Maine in 1910 and became a Michigan corporation in 1968. Consumers owns and operates electric generation and distribution facilities and gas transmission, storage, and distribution facilities. It provides electricity and/or natural gas to 6.7 million of Michigans 10 million residents. Consumers rates and certain other aspects of its business are subject to the jurisdiction of the MPSC and FERC, as well as to NERC reliability standards, as described in Item 1. BusinessCMS Energy and Consumers Regulation. Consumers consolidated operating revenue was $8.2 billion in 2022, $7.0 billion in 2021, and $6.2 billion in 2020. For further information about operating revenue, income, and assets and liabilities attributable to Consumers electric and gas utility operations, see Item 8. Financial Statements and Supplementary DataConsumers Consolidated Financial Statements and Notes to the Consolidated Financial Statements. Consumers owns its principal properties in fee, except that most electric lines, gas mains, and renewable generation projects are located below or adjacent to public roads or on land owned by others and are accessed by Consumers through easements, leases, and other rights. Almost all of Consumers properties are subject to the lien of its First Mortgage Bond Indenture. For additional information on Consumers properties, see Item 1. BusinessBusiness SegmentsConsumers Electric UtilityElectric Utility Properties and Business SegmentsConsumers Gas UtilityGas Utility Properties. Table of Contents In 2022, Consumers served 1.9 million electric customers and 1.8 million gas customers in Michigans Lower Peninsula. Presented in the following map are Consumers service territories: ##TABLE_START Electric service territory Gas service territory Combination electric and gas service territory Electric generation and battery storage facilities ##TABLE_ENDCMS Energy and ConsumersThe Triple Bottom Line For information regarding CMS Energys and Consumers purpose and impact on the triple bottom line of people, planet, and profit, see Item 7. Managements Discussion and Analysis of Financial Condition and Results of OperationsExecutive Overview. Business Segments Consumers Electric Utility Electric Utility Operations: Consumers electric utility operations, which include the generation, purchase, distribution, and sale of electricity, generated operating revenue of $5.4 billion in 2022, $5.0 billion in 2021, and $4.4 billion in 2020. Consumers electric utility customer base consists of a mix of primarily residential, commercial, and diversified industrial customers in Michigans Lower Peninsula. Table of Contents Presented in the following illustration is Consumers 2022 electric utility operating revenue of $5.4 billion by customer class: Consumers electric utility operations are not dependent on a single customer, or even a few customers, and the loss of any one or even a few of Consumers largest customers is not reasonably likely to have a material adverse effect on Consumers financial condition. In 2022, Consumers electric deliveries were 37 billion kWh, which included ROA deliveries of three billion kWh, resulting in net bundled sales of 34 billion kWh. In 2021, Consumers electric deliveries were 36 billion kWh, which included ROA deliveries of three billion kWh, resulting in net bundled sales of 33 billion kWh. Consumers electric utility operations are seasonal. The consumption of electric energy typically increases in the summer months, due primarily to the use of air conditioners and other cooling equipment. Table of Contents Presented in the following illustration are Consumers monthly weather-normalized electric deliveries (deliveries adjusted to reflect normal weather conditions) to its customers, including ROA deliveries, during 2022 and 2021: Consumers 2022 summer peak demand was 8,061 MW, which included ROA demand of 532 MW. For the 2021-2022 winter season, Consumers peak demand was 5,559 MW, which included ROA demand of 447 MW. As required by MISO reserve margin requirements, Consumers owns or controls, through long-term PPAs and short-term capacity purchases, all of the capacity required to supply its projected firm peak load and necessary reserve margin for summer 2023. Electric Utility Properties: Consumers owns and operates electric generation and distribution facilities. For details about Consumers electric generation facilities, see the Electric Utility Generation and Supply Mix section that follows this Electric Utility Properties section. Consumers distribution system consists of: 212 miles of high-voltage distribution overhead lines operating at 138 kV four miles of high-voltage distribution underground lines operating at 138 kV 4,430 miles of high-voltage distribution overhead lines operating at 46 kV and 69 kV 19 miles of high-voltage distribution underground lines operating at 46 kV 82,326 miles of electric distribution overhead lines 9,501 miles of underground distribution lines 1,093 substations with an aggregate transformer capacity of 27 million kVA three battery facilities with storage capacity of 2 MWh Consumers is interconnected to the interstate high-voltage electric transmission system owned by METC and operated by MISO. Consumers is also interconnected to neighboring utilities and to other transmission systems. Table of Contents Electric Utility Generation and Supply Mix: Consumers Clean Energy Plan details its strategy to meet customers long-term energy needs and provides the foundation for its goal to achieve net-zero carbon emissions from its electric business by 2040. This goal includes not only emissions from owned generation, but also emissions from the generation of power purchased through long-term PPAs and from the MISO energy market. In June 2022, Consumers received approval of its 2021 IRP, which updated its Clean Energy Plan. With these updates, Consumers expects to meet 90 percent of its customers needs with clean energy sources by 2040 through execution of its plan, which calls for replacing its coal-fueled generation predominantly with investment in renewable energy. New technologies and carbon offset measures including, but not limited to, carbon sequestration, methane emission capture, forest preservation, and reforestation may be used to close the gap to achieving net-zero carbon emissions. Specifically, the Clean Energy Plan provides for the retirement of the D.E. Karn coal-fueled generating units in 2023 and the J.H. Campbell coal-fueled generating units in 2025. For further information on Consumers progress towards its net-zero carbon emissions goal, see Item 7. Managements Discussion and Analysis of Financial Condition and Results of OperationsExecutive Overview. Table of Contents Presented in the following table are

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details about Consumers 2022 electric generation and supply mix: ##TABLE_START Name and Location (Michigan) Number of Units and Year Entered Service 2022 Generation Capacity (MW) 1 2022 Electric Supply (GWh) Coal steam generation J.H. Campbell 1 2 West Olive 2 2 Units, 1962-1967 610 2,869 J.H. Campbell 3 West Olive 2,3 1 Unit, 1980 785 4,449 D.E. Karn 1 2 Essexville 4 2 Units, 1959-1961 489 2,899 1,884 10,217 Oil/Gas steam generation D.E. Karn 3 4 Essexville 2 Units, 1975-1977 1,213 167 Hydroelectric Ludington Ludington 6 Units, 1973 1,109 5 (370) 6 Conventional hydro generation 35 Units, 1906-1949 78 381 1,187 11 Gas combined cycle Jackson Jackson 1 Unit, 2002 535 2,205 Zeeland Zeeland 3 Units, 2002 533 3,456 1,068 5,661 Gas combustion turbines Zeeland (simple cycle) Zeeland 2 Units, 2001 317 860 Wind generation Cross Winds Energy Park Tuscola County 114 Turbines, 2014, 2018, and 2019 33 747 Lake Winds Energy Park Mason County 56 Turbines, 2012 13 269 Gratiot Farms Wind Project Gratiot County 60 Turbines, 2020 10 421 Crescent Wind Farm Hillsdale County 60 Turbines, 2021 8 392 64 1,829 Solar generation Solar Gardens Allendale, Cadillac, and Kalamazoo 16,852 Panels, 2016-2021 3 7 Total owned generation 5,736 18,752 Purchased power 7 Coal generation T.E.S. Filer City 60 500 Gas generation MCV Facility 8 1,240 5,857 Other gas generation 155 1,325 Nuclear generation 9 2,692 Wind generation 60 1,017 Solar generation 71 227 Other renewable generation 204 1,197 1,790 12,815 Net interchange power 10 3,943 Total purchased and interchange power 1,790 16,758 Total supply 7,526 35,510 Less distribution and transmission loss 1,940 Total net bundled sales 33,570 ##TABLE_ENDTable of Contents 1 Represents generation capacity during the summer months (planning year 2022 capacity as reported to MISO and limited by interconnection service limits). For wind and solar generation, the amount represents the effective load-carrying capability. 2 Consumers plans to retire these generating units in 2025. 3 Represents Consumers share of the capacity of the J.H. Campbell 3 unit, net of the 6.69percent ownership interest of the Michigan Public Power Agency and Wolverine Power Supply Cooperative, Inc, each a non-affiliated company. 4 Consumers plans to retire these generating units in 2023. 5 Represents Consumers 51percent share of the capacity of Ludington. DTE Electric holds the remaining 49percent ownership interest. 6 Represents Consumers share of net pumped-storage generation. The pumped-storage facility consumes electricity to pump water during off-peak hours for storage in order to generate electricity later during peakdemand hours. 7 Represents purchases under long-term PPAs. 8 For information about Consumers long-term PPA related to the MCV Facility, see Item 8. Financial Statements and Supplementary DataNotes to the Consolidated Financial StatementsNote 3, Contingencies and CommitmentsContractual Commitments. 9 Represents purchases from a nuclear generating facility that closed in May 2022. 10 Represents purchases from the MISO energy market. Table of Contents Presented in the following table are the sources of Consumers electric supply for the last three years: ##TABLE_START GWh Years Ended December 31 2022 2021 2020 Owned generation Coal 10,217 10,861 7,960 Gas 6,684 5,555 5,883 Renewable energy 2,217 1,974 1,505 Oil 4 7 6 Net pumped storage 1 (370) (321) (371) Total owned generation 18,752 18,076 14,983 Purchased power 2 Gas generation 7,182 5,862 7,346 Nuclear generation 2,692 6,901 6,898 Renewable energy generation 2,441 2,408 2,225 Coal generation 500 494 513 Net interchange power 3 3,943 645 2,655 Total purchased and interchange power 16,758 16,310 19,637 Total supply 35,510 34,386 34,620 ##TABLE_END1 Represents Consumers share of net pumped-storage generation. During 2022, the pumped-storage facility consumed 1,339 GWh of electricity to pump water during off-peak hours for storage in order to generate 969 GWh of electricity later during peak-demand hours. 2 Represents purchases under long-term PPAs. 3 Represents purchases from the MISO energy market. During 2022, Consumers acquired 47 percent of the electricity it provided to customers through long-term PPAs and the MISO energy market. Consumers offers its generation into the MISO energy market on a day-ahead and real-time basis and bids for power in the market to serve the demand of its customers. Consumers is a net purchaser of power and supplements its generation capability with purchases from the MISO energy market. At December 31, 2022, Consumers had future commitments to purchase capacity and energy under long-term PPAs with various generating plants. These contracts require monthly capacity payments based on the plants availability or deliverability. The payments for 2023 through 2050 are estimated to total $8.5 billion and, for each of the next five years, range from $0.7 billion to $0.8 billion annually. These amounts may vary depending on plant availability and fuel costs. For further information about Consumers future capacity and energy purchase obligations, see Item 7. Managements Discussion and Analysis of Financial Condition and Results of OperationsCapital Resources and LiquidityOther Material Cash Requirements and Item 8. Financial Statements and Supplementary DataNotes to the Consolidated Financial StatementsNote 3, Contingencies and CommitmentsContractual Commitments. During 2022, 29 percent of the energy Consumers provided to customers was generated by its coal-fueled generating units, which burned six million tons of coal and produced a combined total of 10,217 GWh of electricity. In order to obtain the coal it needs, Consumers enters into physical coal supply contracts. Table of Contents At December 31, 2022, Consumers had future commitments to purchase coal through 2024; payment obligations under these contracts totaled $104 million. Most of Consumers rail-supplied coal contracts have fixed prices, although some contain market-based pricing. At December 31, 2022, Consumers had 85 percent of its 2023 expected coal requirements under contract, as well as a 34-day supply of coal on hand. In conjunction with its coal supply contracts, Consumers leases a fleet of railcars and has transportation contracts with various companies to provide rail services for delivery of purchased coal to Consumers generating facilities. Consumers coal transportation contracts are future commitments and expire on various dates through 2025; payment obligations under these contracts totaled $428 million at December 31, 2022. During 2022, 19 percent of the energy Consumers provided to customers was generated by its natural gasfueled generating units, which burned 49 bcf of natural gas and produced a combined total of 6,684 GWh of electricity. In order to obtain the gas it needs for electric generation fuel, Consumers electric utility purchases gas from the market near the time of consumption, at prices that allow it to compete in the electric wholesale market. For the Jackson and Zeeland plants, Consumers utilizes an agent that owns firm transportation rights to each plant to purchase gas from the market and transport the gas to the facilities. For units 3 4 of D.E. Karn, Consumers holds gas transportation contracts to transport to the plant gas that Consumers or an agent purchase from the market. Electric Utility Competition: Consumers electric utility business is subject to actual and potential competition from many sources, in both the wholesale and retail markets, as well as in electric generation, electric delivery, and retail services. Michigan law allows electric customers in Consumers service territory to buy electric generation service from alternative electric suppliers in an aggregate amount capped at ten percent of Consumers sales, with certain exceptions. At December 31, 2022, electric deliveries under the ROA program were at the tenpercent limit. Of Consumers 1.9 million electric customers, fewer than 300, or 0.02 percent, purchased electric generation service under the ROA program. For additional information, see Item 7. Managements Discussion and Analysis of Financial Condition and Results of OperationsOutlookConsumers Electric Utility Outlook and Uncertainties. Consumers also faces competition or potential competition associated with industrial customers relocating all or a portion of their production capacity outside of Consumers service territory for economic reasons; municipalities owning or operating competing electric delivery systems; and customer self-generation. Consumers addresses this competition in various ways, including: aggressively controlling operating, maintenance, and fuel costs and passing savings on to customers providing renewable energy options and energy waste reduction programs providing competitive rate-design options, particularly for large energy-intensive customers offering tariff-based incentives that support economic development monitoring activity in adjacent geographical areas Table of Contents Consumers Gas Utility Gas Utility Operations: Consumers gas utility operations, which include the purchase, transmission, storage, distribution, and sale of natural gas, generated operating revenue of $2.7 billion in 2022, $2.1 billion in 2021, and $1.8 billion in 2020. Consumers gas utility customer base consists of a mix of primarily residential, commercial, and diversified industrial customers in Michigans Lower Peninsula. Presented in the following illustration is Consumers 2022 gas utility operating revenue of $2.7 billion by customer class: Consumers gas utility operations are not dependent on a single customer, or even a few customers, and the loss of any one or even a few of Consumers largest customers is not reasonably likely to have a material adverse effect on Consumers financial condition. In 2022, deliveries of natural gas through Consumers pipeline and distribution network, including off-system transportation deliveries, totaled 391 bcf, which included GCC deliveries of 34 bcf. In 2021, deliveries of natural gas through Consumers pipeline and distribution network, including off-system transportation deliveries, totaled 347 bcf, which included GCC deliveries of 33 bcf. Consumers gas utility operations are seasonal. The consumption of natural gas increases in the winter, due primarily to colder temperatures and the resulting use of natural gas as heating fuel. Consumers injects natural gas into storage during the summer months for use during the winter months. During 2022, 48 percent of the natural gas supplied to all customers during the winter months was supplied from storage. Table of Contents Presented in the following illustration are Consumers monthly weather-normalized natural gas deliveries (deliveries adjusted to reflect normal weather conditions) to its customers, including GCC deliveries, during 2022 and 2021: Gas Utility Properties: Consumers gas transmission, storage, and distribution system consists of: 2,380 miles of transmission lines 15 gas storage fields with a total storage capacity of 309 bcf and a working gas volume of 151 bcf 28,170 miles of distribution mains eight compressor stations with a total of 157,893 installed and available horsepower Under its Methane Reduction Plan, Consumers has set a goal of net-zero methane emissions from its natural gas delivery system by 2030. Consumers plans to reduce methane emissions from its system by about 80 percent by accelerating the replacement of aging pipe, rehabilitating or retiring outdated infrastructure, and adopting new technologies and practices. The remaining emissions will likely be offset by purchasing and/or producing renewable natural gas. For further information on Consumers progress towards its net-zero methane emissions goal, see Item 7. Managements Discussion and Analysis of Financial Condition and Results of OperationsExecutive Overview. Table of Contents Gas Utility Supply: In 2022, Consumers purchased 86 percent of the gas it delivered from U.S. suppliers. The remaining 14 percent was purchased from authorized GCC suppliers and delivered by Consumers to customers in the GCC program. Presented in the following illustration are the supply arrangements for the gas Consumers delivered to GCC and GCR customers during 2022: Firm gas transportation or firm city-gate contracts are those that define a fixed amount, price, and delivery time frame. Consumers firm gas transportation contracts are with Panhandle Eastern Pipe Line Company and Trunkline Gas Company, LLC, each a nonaffiliated company. Under these contracts, Consumers purchases and transports gas to Michigan for ultimate delivery to its customers. Consumers firm gas transportation contracts expire on various dates through 2024 with planned contract volumes providing 38 percent of Consumers total forecasted gas supply requirements for 2023. Consumers purchases the balance of its required gas supply under firm city-gate contracts and through authorized suppliers under the GCC program. Gas Utility Competition: Competition exists in various aspects of Consumers gas utility business. Competition comes from GCC and transportation programs; system bypass opportunities for new and existing customers; and from alternative fuels and energy sources, such as propane, oil, and electricity. Table of Contents NorthStar Clean EnergyNon-Utility Operations and Investments NorthStar Clean Energy, through various subsidiaries and certain equity investments, is engaged in domestic independent power production, including the development and operation of renewable generation, and the marketing of independent power production. NorthStar Clean Energys operating revenue was $445 million in 2022, $308 million in 2021, and $229 million in 2020.

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Independent Power Production: Presented in the following table is information about the independent power plants in which CMS Energy had an ownership interest at December 31, 2022: ##TABLE_START Location Ownership Interest (%) Primary Fuel Type Gross Capacity (MW) 1 2022 Net Generation (GWh) Dearborn, Michigan 100 Natural gas 770 4,786 Gaylord, Michigan 100 Natural gas 134 14 Paulding County, Ohio 100 Wind 100 317 Comstock, Michigan 100 Natural gas 76 111 Delta Township, Michigan 100 Solar 24 40 Phillips, Wisconsin 100 Solar 3 5 Paulding County, Ohio 100 Solar and storage 3 2 Coke County, Texas 51 Wind 525 1,894 Filer City, Michigan 50 Coal 73 498 New Bern, North Carolina 50 Wood waste 50 291 Flint, Michigan 50 Wood waste 40 163 Grayling, Michigan 50 Wood waste 38 219 Total 1,836 8,340 ##TABLE_END1 Represents the intended full-load sustained output of each plant. The amount of capacity relating to CMS Energys ownership interest was 1,478 MW and net generation relating to CMS Energys ownership interest was 6,826 GWh at December 31, 2022. The operating revenue from independent power production was $58 million in 2022, $48 million in 2021, and $32 million in 2020. Energy Resource Management: CMS ERM purchases and sells energy commodities in support of CMS Energys generating facilities with a focus on optimizing CMS Energys independent power production portfolio. In 2022, CMS ERM marketed two bcf of natural gas and 6,494 GWh of electricity. Electricity marketed by CMS ERM was generated by independent power production of NorthStar Clean Energy and by unrelated third parties. CMS ERMs operating revenue was $387 million in 2022, $260 million in 2021, and $197 million in 2020. NorthStar Clean Energy Competition: NorthStar Clean Energy competes with other independent power producers. The needs of this market are driven by electric demand and the generation available. Table of Contents CMS Energy and Consumers Regulation CMS Energy, Consumers, and their subsidiaries are subject to regulation by various federal, state, and local governmental agencies, including those described in the following sections. If CMS Energy or Consumers failed to comply with applicable laws and regulations, they could become subject to fines, penalties, or disallowed costs, or be required to implement additional compliance, cleanup, or remediation programs, the cost of which could be material. For more information on the potential impacts of government regulation affecting CMS Energy and Consumers, see Item 1A. Risk Factors, Item 7. Managements Discussion and Analysis of Financial Condition and Results of OperationsOutlook, and Item 8. Financial Statements and Supplementary DataNotes to the Consolidated Financial StatementsNote 2, Regulatory Matters. FERC and NERC FERC has exercised limited jurisdiction over several independent power plants and exempt wholesale generators in which NorthStar Clean Energy has ownership interests, as well as over CMS ERM, CMS Gas Transmission, and DIG. FERCs jurisdiction includes, among other things, acquisitions, operations, disposals of certain assets and facilities, services provided and rates charged, and conduct among affiliates. FERC also has limited jurisdiction over holding company matters with respect to CMS Energy. FERC, in connection with NERC and with regional reliability organizations, also regulates generation and transmission owners and operators, load serving entities, purchase and sale entities, and others with regard to reliability of the bulk power system. FERC regulates limited aspects of Consumers gas business, principally compliance with FERC capacity release rules, shipping rules, the prohibition against certain buy/sell transactions, and the price-reporting rule. FERC also regulates certain aspects of Consumers electric operations, including compliance with FERC accounting rules, wholesale and transmission rates, operation of licensed hydroelectric generating plants, transfers of certain facilities, corporate mergers, and issuances of securities. MPSC Consumers is subject to the jurisdiction of the MPSC, which regulates public utilities in Michigan with respect to retail utility rates, accounting, utility services, certain facilities, certain asset transfers, corporate mergers, and other matters. The Michigan Attorney General, ABATE, the MPSC Staff, residential customer advocacy groups, environmental organizations, and certain other parties typically participate in MPSC proceedings concerning Consumers. These parties often challenge various aspects of those proceedings, including the prudence of Consumers policies and practices, and seek cost disallowances and other relief. The parties also have appealed significant MPSC orders. Rate Proceedings: For information regarding open rate proceedings, see Item 7. Managements Discussion and Analysis of Financial Condition and Results of OperationsOutlook and Item 8. Financial Statements and Supplementary DataNotes to the Consolidated Financial StatementsNote 2, Regulatory Matters. Table of Contents Other Regulation The U.S. Secretary of Energy regulates imports and exports of natural gas and has delegated various aspects of this jurisdiction to FERC and the U.S. Department of Energys Office of Fossil Fuels. The U.S. Department of Transportations Office of Pipeline Safety regulates the safety and security of gas pipelines through the Natural Gas Pipeline Safety Act of 1968 and subsequent laws. The Transportation Security Administration, an agency of the U.S. Department of Homeland Security, regulates certain activities related to the safety and security of natural gas pipelines. CMS Energy and Consumers Environmental Strategy and Compliance CMS Energy and Consumers are committed to protecting the environment; this commitment extends beyond compliance with applicable laws and regulations. Consumers Clean Energy Plan details its strategy to meet customers long-term energy needs and provides the foundation for its goal to achieve net-zero carbon emissions from its electric business by 2040. This goal includes not only emissions from owned generation, but also emissions from the generation of power purchased through long-term PPAs and from the MISO energy market. Consumers expects to meet 90 percent of its customers needs with clean energy sources by 2040 through execution of its Clean Energy Plan, which calls for replacing its coal-fueled generation predominantly with investment in renewable energy. New technologies and carbon offset measures including, but not limited to, carbon sequestration, methane emission capture, forest preservation, and reforestation may be used to close the gap to achieving net-zero carbon emissions. In June 2022, Consumers received approval of its 2021 IRP, which updated its Clean Energy Plan. With these updates, Consumers will eliminate the use of coal-fueled generation in 2025 and forecasts renewable energy capacity levels of over

60 percent in 2040. For additional information on Consumers Clean Energy Plan, see Item 7. Managements Discussion and Analysis of Financial Condition and Results of OperationsOutlookConsumers Electric Utility Outlook and Uncertainties. In addition to Consumers efforts to reduce the electric utilitys carbon footprint, it is also making efforts to reduce the gas utilitys methane footprint. Under its Methane Reduction Plan, Consumers has set a goal of net-zero methane emissions from its natural gas delivery system by 2030. Consumers plans to reduce methane emissions from its system by about 80 percent by accelerating the replacement of aging pipe, rehabilitating or retiring outdated infrastructure, and adopting new technologies and practices. The remaining emissions will likely be offset by purchasing and/or producing renewable natural gas. For additional information on Consumers Methane Reduction Plan, see Item 7. Managements Discussion and Analysis of Financial Condition and Results of OperationsOutlookConsumers Gas Utility Outlook and UncertaintiesGas Environmental Outlook. CMS Energy, Consumers, and their subsidiaries are subject to various federal, state, and local environmental regulations for solid waste management, air and water quality, and other matters. Consumers expects to recover costs to comply with environmental regulations in customer rates but cannot guarantee this result. For additional information concerning environmental matters, see Item 1A. Risk Factors, Item 7. Managements Discussion and Analysis of Financial Condition and Results of OperationsOutlook, and Item 8. Financial Statements and Supplementary DataNotes to the Consolidated Financial StatementsNote 3, Contingencies and Commitments. Table of Contents CMS Energy has recorded a $45 million liability for its subsidiaries obligations associated with Bay Harbor and Consumers has recorded a $62 million liability for its obligations at a number of former MGP sites. For additional information, see Item 1A. Risk Factors and Item 8. Financial Statements and Supplementary DataNotes to the Consolidated Financial StatementsNote 3, Contingencies and Commitments. Costs related to the construction, operation, corrective action, and closure of solid waste disposal facilities for coal ash are significant. Consumers coal ash disposal areas are regulated under Michigans solid waste rules and by the EPAs rules regulating CCRs. To address some of the requirements of these rules, Consumers has converted all of its fly ash handling systems to dry systems. In addition, Consumers ash facilities have programs designed to protect the environment and are subject to quarterly EGLE inspections. Consumers estimate of capital and cost of removal expenditures to comply with regulations relating to ash disposal is $205 million from 2023 through 2027. Consumers future costs to comply with solid waste disposal regulations may vary depending on future legislation, litigation, executive orders, treaties, or rulemaking. For further information concerning estimated capital expenditures related to environmental matters, see Item 7. Managements Discussion and Analysis of Financial Condition and Results of OperationsOutlookConsumers Electric Utility Outlook and UncertaintiesElectric Environmental Outlook. Insurance CMS Energy and its subsidiaries, including Consumers, maintain insurance coverage generally similar to comparable companies in the same lines of business. The insurance

policies are subject to terms, conditions, limitations, and exclusions that might not fully compensate CMS Energy or Consumers for all losses. A portion of each loss is generally assumed by CMS Energy or Consumers in the form of deductibles and self-insured retentions that, in some cases, are substantial. As CMS Energy or Consumers renews its policies, it is possible that some of the present insurance coverage may not be renewed or obtainable on commercially reasonable terms due to restrictive insurance markets. Human Capital CMS Energy and Consumers employ a highly trained and skilled workforce comprised of union, nonunion, and seasonal employees. Presented in the following table are the number of employees of CMS Energy and Consumers: ##TABLE_START December 31 2022 2021 2020 CMS Energy, including Consumers Full-time and part-time employees 8,560 8,509 8,234 Seasonal employees 1 513 613 603 Total employees 9,073 9,122 8,837 Consumers Full-time and part-time employees 8,366 8,314 7,627 Seasonal employees 1 513 613 603 Total employees 8,879 8,927 8,230 ##TABLE_END1 Consumers seasonal workforce peaked at 587 employees during 2022, 622 employees during 2021, and 603 employees during 2020. Seasonal employees work primarily during the construction season. Table of Contents At December 31, 2022, unions represented 41 percent of CMS Energys employees and 42 percent of Consumers employees. The UWUA represents Consumers operating, maintenance, construction, and customer contact center employees. The USW represents Zeeland plant employees. The UWUA and USW agreements expire in 2025. The safety of employees, customers, and the general public is a priority of CMS Energy and Consumers. Accordingly, CMS Energy and Consumers have worked to integrate a set of safety principles into their business operations and culture. These principles include complying with applicable safety, health, and security regulations and implementing programs and processes aimed at continually improving safety and security conditions. On an annual basis, CMS Energy and Consumers set various safety goals, with their primary measure being the OSHA recordable incident rate. The recordable incident rate was 1.17 in 2022 and 1.54 in 2021. The target recordable incident rate for 2023 is 1.07. Over the last ten years, Consumers OSHA recordable incident rate has decreased by 34 percent. Within the utility industry, there is strong competition for rare, high-demand talent, including those related to renewable energy generation, technology, and data analytics. In order to address this competition and to be able to meet their human capital needs, CMS Energy and Consumers provide compensation and benefits that are competitive with industry peers. Furthermore, CMS Energy and Consumers have developed a comprehensive talent strategy, the People Strategy, to attract, develop, and retain highly skilled employees. The strategy focuses on three areas, which are summarized below. Cultivating a Purpose-Driven Culture: This goal is aimed at ensuring all co-workers understand how their work drives CMS Energys and Consumers key strategic goals. CMS Energys and Consumers progress toward a purpose-driven culture is measured through an engagement index and an empowerment index developed from data obtained through an annual employee engagement survey of union and non-union co-workers administered by a third party. For the year ended December 31, 2022, the employee engagement index score, which measures the percentage of employees that feel satisfied with the company, was 71 percent and ranked in the second quartile of general industry companies. The employee empowerment index score, which measures the percentage of employees that feel the workplace promotes empowerment, was 54 percent and ranked in the third quartile of general industry companies. The general industry benchmark was created by the third party who administered the survey through a targeted sampling of working adults within the U.S. who work for firms with widely respected reputations. CMS Energy and Consumers have a goal to achieve a first-quartile empowerment index score by 2030. Creating a Breakthrough Employee Experience: A breakthrough employee experience is one that instills pride and ownership in ones work. To measure progress toward a breakthrough employee experience, CMS Energy and Consumers measure employees satisfaction with people processes, such as performance management and hiring and onboarding new employees. For the year ended December 31, 2022, the employee experience index was 54 percent; CMS Energy and Consumers have a goal to achieve a score of 80 percent by 2030. Building Skill Sets at Scale: With an overarching goal of ensuring employees have the right skills to succeed, CMS Energy and Consumers measure progress in this area through achievement of workforce planning and hiring milestones and through a first-time skill attainment index to evaluate the effectiveness of training. CMS Energy and Consumers develop skill sets in co-workers through a variety of means, including union apprenticeship programs and yearly trainings for newly required skills. In 2021, CMS Energy and Consumers launched a full-scale development program for leaders to enable robust succession planning and improve employee engagement and empowerment. Table of Contents This talent strategy allows CMS Energy and Consumers to shape employees experience and enable leaders to coach and develop co-workers, source talent, and anticipate and adjust to changing skill sets in the business environment. Diversity, Equity, and Inclusion As a part of their People Strategy, CMS Energy and Consumers also employ a comprehensive diversity, equity, and inclusion strategy designed to embed diversity, equity, and inclusion into all aspects of their business. This is done through embedding standards for diversity, equity, and inclusion into all company processes and ensuring these standards are incorporated into all employee experiences. To measure their success, CMS Energy and Consumers utilize select questions in the annual engagement survey to create a diversity, equity, and inclusion index. For the year ended December 31, 2022, the diversity, equity, and inclusion index score was 72 percent. CMS Energy and Consumers are committed to building an inclusive workplace that embraces the diverse makeup of the communities that they serve. The following table presents the composition of CMS Energys and Consumers workforce: ##TABLE_START December 31, 2022 CMS Energy, including Consumers Consumers Percent female employees 27 % 28 % Percent racially or ethnically diverse employees 12 12 Percent employees with disabilities 5 5 Percent veteran employees 11 11 ##TABLE_ENDCo-workers are also empowered to engage in employee resource groups and events that encourage candid conversations around diversity, equity, and inclusion. There are eight employee resource groups available to all co-workers; these groups are, by date of origin: the Womens Advisory Panel, contributing to the achievement of the corporate strategy by supporting the retention, development, and success of women the Minority Advisory Panel, promoting a culture of diversity and inclusion among all racial and ethnic minorities through education, leadership, development, and networking the Womens Engineering Network, connecting and empowering women in the science, technology, engineering, and mathematics fields, while building capabilities to support company objectives the Veterans Advisory Panel, supporting former and active military personnel and assisting in recruiting and retaining veterans through career development GEN-ERGY, a multigenerational group designed to bridge the gap of learning, networking, and mentoring across the generations of the workforce the Pride Alliance of Consumers Energy, promoting an inclusive environment that is safe, supportive, and respectful for lesbian, gay, bi-sexual, and transgender persons and allies capABLE, aimed at removing barriers and creating pathways to meaningful work for employees of all abilities Interfaith, a space for co-workers of all backgrounds to gather and celebrate their unique beliefs, creating an environment of understanding and respect for all faiths, religions, and spiritual beliefs, including those with no faith affiliation Table of Contents Information About CMS Energys and Consumers Executive Officers Presented in the following table are the company positions held during the last five years for each of CMS Energys and Consumers executive officers as of February 3, 2023: ##TABLE_START Name, Age, Position(s) Period Garrick J. Rochow (age 48) CMS Energy President, CEO, and Director 12/2020 Present Executive Vice President 1/2020 12/2020 Senior Vice President 7/2016 1/2020 Consumers President, CEO, and Director 12/2020 Present Executive Vice President 1/2020 12/2020 Senior Vice President 7/2016 1/2020 NorthStar Clean Energy Chairman of the Board, CEO, and Director 12/2020 Present Rejji P. Hayes (age 48) CMS Energy Executive Vice President and CFO 5/2017 Present Consumers Executive Vice President and CFO 5/2017 Present NorthStar Clean Energy Executive Vice President, CFO, and Director 5/2017 Present EnerBank Chairman of the Board and Director 10/2018 10/2021 Tonya L. Berry (age 50) CMS Energy Senior Vice President 2/2022 Present Consumers Senior Vice President 2/2022 Present Vice President 11/2018 2/2022 Executive Director, Quality 7/2017 11/2018 Catherine A. Hendrian (age 54) CMS Energy Senior Vice President 4/2017 Present Consumers Senior Vice President 4/2017 Present ##TABLE_ENDTable of Contents ##TABLE_START Name, Age, Position(s) Period Brandon J. Hofmeister (age 46) CMS Energy Senior Vice President 7/2017 Present Consumers Senior Vice President 7/2017 Present NorthStar Clean Energy Senior Vice President 9/2017 Present Shaun M. Johnson (age 44) CMS Energy Senior Vice President and General Counsel 5/2019 Present Vice President and Deputy General Counsel 4/2016 5/2019 Consumers Senior Vice President and General Counsel 5/2019 Present Vice President and Deputy General Counsel 4/2016 5/2019 NorthStar Clean Energy Senior Vice

President, General Counsel, and Director 4/2019 Present Vice President and General Counsel 10/2018 4/2019 EnerBank Senior Vice President and General Counsel 8/2018 6/2020 Venkat Dhenuvakonda Rao (age 52) CMS Energy Senior Vice President 9/2016 Present Consumers Senior Vice President 9/2016 Present NorthStar Clean Energy Director 11/2017 Present Senior Vice President 9/2016 Present Brian F. Rich (age 48) CMS Energy Senior Vice President and Chief Customer Officer 8/2019 Present Senior Vice President and Chief Information Officer 7/2016 8/2019 Consumers Senior Vice President and Chief Customer Officer 8/2019 Present Senior Vice President and Chief Information Officer 7/2016 8/2019 LeeRoy Wells, Jr. (age 44) CMS Energy Senior Vice President 12/2020 Present Consumers Senior Vice President 12/2020 Present Vice President 8/2017 12/2020 ##TABLE_ENDTable of Contents ##TABLE_START Name, Age, Position(s) Period Scott B. McIntosh (age 47) CMS Energy Vice President, Controller, and CAO 9/2021 Present Vice President and Controller 6/2021 9/2021 Vice President 9/2015 6/2021 Consumers Vice President, Controller, and CAO 9/2021 Present Vice President and Controller 6/2021 9/2021 Vice President 9/2015 6/2021 NorthStar Clean Energy Vice President, Controller, and CAO 9/2021 Present Vice President and Controller 6/2021 9/2021 Vice President 9/2015 6/2021 ##TABLE_ENDThere are no family relationships among executive officers and directors of CMS Energy or Consumers. The list of directors and their biographies will be included in CMS Energys and Consumers definitive proxy statement for their 2023 Annual Meetings of Shareholders to be held May 5, 2023. The term of office of each of the executive officers extends to the first meeting of each of the Boards of Directors of CMS Energy and Consumers after the next annual election of Directors of CMS Energy and Consumers (to be held on May 5, 2023). Available Information CMS Energys internet address is www.cmsenergy.com. CMS Energy routinely posts important information on its website and considers the Investor Relations section, www.cmsenergy.com/investor-relations, a channel of distribution for material information. Information contained on CMS Energys website is not incorporated herein. CMS Energys and Consumers annual reports on Form 10K, quarterly reports on Form 10Q, current reports on Form 8-K, and any amendments to those reports filed pursuant to Section 13(a) or 15(d) of the Exchange Act are accessible free of charge on CMS Energys website. These reports are available soon after they are electronically filed with the SEC. Also on CMS Energys website are CMS Energys and Consumers: Corporate Governance Principles Articles of Incorporation Bylaws Charters and Codes of Conduct (including the Charters of the Audit Committee, Compensation and Human Resources Committee, Finance Committee, and Governance, Sustainability and Public Responsibility Committee, as well as the Employee, Board of Directors, and Third Party Codes of Conduct) CMS Energy will provide this information in print to any stockholder who requests it. The SEC maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. The address is www.sec.gov. Table of Contents Item 1A. Risk Factors CMS Energy and Consumers are exposed to a variety of factors, often beyond their control, that are difficult to predict and that involve uncertainties that may materially adversely affect CMS Energys or Consumers business, liquidity, financial condition, or results of operations. Additional risks and uncertainties not presently known or that management believes to be immaterial may also adversely affect CMS Energy or Consumers. The risk factors described in the following sections, as well as the other information included in this report and in other documents filed with the SEC, should be considered carefully before making an investment in securities of CMS Energy or Consumers. Risk factors of Consumers are also risk factors of CMS Energy. Investment/Financial Risks CMS Energy depends on dividends from its subsidiaries to meet its debt service obligations. Due to its holding company structure, CMS Energy depends on dividends from its subsidiaries to meet its debt service and other payment obligations. If sufficient dividends were not paid to CMS Energy by its subsidiaries, CMS Energy might not be able to generate the funds necessary to fulfill its payment obligations. Consumers ability to pay dividends or acquire its own stock from CMS Energy is limited by restrictions contained in Consumers preferred stock provisions and potentially by other legal restrictions, such as certain terms in its articles of incorporation and FERC requirements. CMS Energy has indebtedness that could limit its financial flexibility and its ability to meet its debt service obligations. The level of CMS Energys present and future indebtedness could have several important effects on its future operations, including, among others, that: a significant portion of CMS Energys cash flow from operations could be dedicated to the payment of principal and interest on its indebtedness and would not be available for other purposes covenants contained in CMS Energys existing debt arrangements, which require it to meet certain financial tests, could affect its flexibility in planning for, and reacting to, changes in its business CMS Energys ability to obtain additional financing for working capital, capital expenditures, acquisitions, and general corporate and other purposes could become limited CMS Energy could be placed at a competitive disadvantage to its competitors that are less leveraged CMS Energys vulnerability to adverse economic and industry conditions could increase CMS Energys future credit ratings could fluctuate CMS Energys ability to meet its debt service obligations and to reduce its total indebtedness will depend on its future performance, which will be subject to general economic conditions, industry cycles, changes in laws or regulatory decisions, and financial, business, and other factors affecting its operations, many of which are beyond its control. CMS Energy cannot make assurances that its businesses will continue to generate sufficient cash flow from operations to service its indebtedness, which could require CMS Energy to sell assets or obtain additional financing. Table of Contents CMS Energy and Consumers have financing needs and could be unable to obtain bank financing or access the capital markets. CMS Energy and Consumers rely on the capital markets, as well as on bank syndications, to meet their financial commitments and short-term liquidity needs not otherwise funded internally. Disruptions in the capital and credit markets, or the inability to obtain required FERC authorization for issuances of securities including debt, could adversely affect CMS Energys and Consumers access to liquidity needed for their businesses. Any liquidity disruption could require CMS Energy and Consumers to take measures to conserve cash including, but not limited to, deferring capital expenditures, changing commodity purchasing strategies to avoid collateral-posting requirements, and reducing or eliminating future share repurchases, dividend payments, or other discretionary uses of cash. Entering into new financings is subject in part to capital market receptivity to utility industry securities in general and to CMS Energys and Consumers securities in particular. CMS Energy and Consumers continue to explore financing opportunities to supplement their respective financial strategies. These potential opportunities include refinancing and/or issuing new debt, issuing CMS Energy preferred stock and/or common equity, or entering into commercial paper, bank financing, and leasing arrangements. CMS Energy and Consumers cannot guarantee the capital markets acceptance of their securities. CMS Energy may also, from time to time, repurchase (either in open market transactions or through privately negotiated transactions), redeem, or otherwise retire its outstanding debt. Such activities, if any, will depend on prevailing market conditions, contractual restrictions, and other factors. The amounts involved may or may not be material. Certain of CMS Energys and Consumers securities and those of their affiliates are rated by various credit rating agencies. A reduction or withdrawal of one or more of its credit ratings could have a material adverse impact on CMS Energys or Consumers ability to access capital on acceptable terms and maintain commodity lines of credit, could increase their cost of borrowing, and could cause CMS Energy or Consumers to reduce capital expenditures. If either or both were unable to maintain commodity lines of credit, CMS Energy or Consumers might have to post collateral or make prepayments to certain suppliers under existing contracts. Further, since Consumers provides dividends to CMS Energy, any adverse developments affecting Consumers that result in a lowering of its credit ratings could have an adverse effect on CMS Energys credit ratings. Market performance and other changes could decrease the value of employee benefit plan assets, which then could require substantial funding. The performance of various markets affects the value of assets that are held in trust to satisfy future obligations under CMS Energys and Consumers pension and postretirement benefit plans. CMS Energy and Consumers have significant obligations under these plans and hold significant assets in these trusts. These assets are subject to market fluctuations and will yield uncertain returns, which could fall below CMS Energys and Consumers forecasted return rates. A decline in the market value of the assets or a change in the level of interest rates used to measure the required minimum funding levels could significantly increase the funding requirements of these obligations. Also, changes in demographics, including an increased number of retirements or changes in life expectancy assumptions, could significantly increase the funding requirements of the obligations related to the pension and postretirement benefit plans. Table of Contents Industry/Regulatory Risks Changes to ROA could have a material adverse effect on CMS Energys and Consumers businesses. Michigan law allows electric customers in Consumers service territory to buy electric generation service from alternative electric suppliers in an aggregate amount capped at ten percent of Consumers sales, with certain exceptions. The proportion of Consumers electric deliveries under the ROA program and on the ROA waiting list is over ten percent. Consumers rates are regulated by the MPSC, while alternative electric suppliers charge market-based rates, putting competitive pressure on Consumers electric supply. If the ROA limit were increased or if electric generation service in Michigan were deregulated, it could have a material adverse effect on CMS Energy and Consumers. Distributed energy resources could have a material adverse effect on CMS Energys and Consumers businesses. Michigan law allows customers to use distributed energy resources for their electric energy needs. These distributed energy resources are connected to Consumers electric grid. The state distributed generation program is currently capped by the 2016 Energy Law at one percent of utilities peak loads, but in the settlement of its 2022 electric rate case, Consumers agreed to increase the cap to four percent on its system. Consumers is required to purchase distributed generation customers excess generation at rates determined by the MPSC. Recent FERC policy will also soon allow many customer-owned behind-the-meter and grid-connected distributed energy resources to participate in and receive revenue from wholesale electricity markets. Increased customer use of distributed energy resources could result in a reduction of Consumers electric sales. Third parties operations of distributed energy resources could also potentially have a negative impact on the stability of the grid. An increase in customers use of distributed energy resources, and the rate structure for distributed energy resources customers use of Consumers system and Consumers purchases of their excess generation, could have a material adverse effect on CMS Energy and Consumers. CMS Energy and Consumers are subject to rate regulation, which could have a material adverse effect on financial results. CMS Energy and Consumers are subject to rate regulation. Consumers electric and gas retail rates are set by the MPSC and cannot be changed without regulatory authorization. If rate regulators fail to provide adequate rate relief, it could have a material adverse effect on Consumers or Consumers plans for making significant capital investments. Additionally, increasing rates could result in additional regulatory scrutiny, regulatory or legislative actions, and increased competitive or political pressures, all of which could have a material adverse effect on CMS Energys and Consumers liquidity, financial condition, and results of operations. Orders of the MPSC could limit recovery of costs of providing service. These orders could also result in adverse regulatory treatment of other matters. For example, MPSC orders could prevent or curtail Consumers from shutting off nonpaying customers or could prevent or limit the implementation of a gas revenue mechanism. Regulators could face competitive or political pressures to avoid or limit rate increases for a number of reasons, including economic downturn in the state or decreased customer base, among others. FERC authorizes certain subsidiaries of CMS Energy to sell wholesale electricity at market-based rates. Failure of these subsidiaries to maintain this FERC authority could have a material adverse effect on CMS Energys and Consumers liquidity, financial condition, and results of operations. Transmission rates paid by Consumers and other CMS Energy subsidiaries are also set by FERC, as are the tariff terms Table of Contents governing the participation of Consumers and other CMS Energy subsidiaries in FERC-regulated wholesale electricity markets operated by regional transmission organizations and independent system operators such as MISO and PJM. At least one CMS Energy subsidiary participates in the wholesale electricity markets operated by ERCOT, over which FERC has limited control. The various risks associated with the MPSC and FERC regulation of CMS Energys and Consumers businesses, which include the risk of adverse decisions in any number of rate or regulatory proceedings before either agency, as well as judicial proceedings challenging any agency decisions, could have a material adverse effect on CMS Energy and Consumers. Changes to the tariffs or business practice manuals of certain wholesale market operators such as MISO, PJM, or ERCOT could also have a material adverse effect on CMS Energy and Consumers. Utility regulation, state or federal legislation, and compliance could have a material adverse effect on CMS Energys and Consumers businesses. CMS Energy and Consumers are subject to, or affected by, extensive utility regulation and state and federal legislation. If it were determined that CMS Energy or Consumers failed to comply with applicable laws and regulations, they could become subject to fines, penalties, or disallowed costs, or be required to implement additional compliance, cleanup, or remediation programs, the cost of which could be material. CMS Energy and Consumers cannot predict the impact of new laws, rules, regulations, principles, or practices by federal or state agencies or wholesale electricity market operators, or challenges or changes to present laws, rules, regulations, principles, or practices and the interpretation of any adoption or change. Furthermore, any state or federal legislation concerning CMS Energys or Consumers operations could also have a material adverse effect. FERC, through NERC and its delegated regional entities, oversees reliability of certain portions of the electric grid. CMS Energy and Consumers cannot predict the impact of FERC orders or actions of NERC and its regional entities on electric system reliability. Additionally, national gas pipeline infrastructure has recently been under scrutiny following disruptions related to extreme weather and cyber incidents. In 2021, the Transportation Security Administration issued two mandatory security directives related to natural gas pipelines that apply to Consumers. Additional regulation in this area could adversely affect Consumers gas operations. CMS Energy and Consumers have announced ambitious plans to reduce their impact on climate change and increase the reliability of their electric distribution system. Achieving these plans depends on numerous factors, many of which are outside of their control. Consumers has announced a long-term strategy for delivering clean, reliable, resilient, and affordable energy, including a plan to end coal use in 2025 as set forth in the 2021 IRP. The MPSC, FERC, other regulatory authorities, or other third parties may prohibit, delay, or impair the 2021 IRP and some or all of the 2021 IRP-associated acquisitions of owned or purchased electric generation capacity. Consumers may be unable to acquire, site, and/or permit some or all of the generation capacity proposed in the 2021 IRP. Consumers ability to implement the 2021 IRP may be affected by global supply chain disruptions and changes in the cost, availability, and supply of generation capacity. While CMS Energy and Consumers continue to advocate for advances in technologies required to reduce or eliminate greenhouse gases on a cost-effective basis, such advances are largely outside of CMS Energys and Consumers control. Advancements in technology related to items such as battery storage and electric vehicles may not become commercially available or economically feasible as projected in the 2021 IRP. Customer programs such as energy efficiency and demand response may not realize the projected levels of customer participation. Table of Contents Consumers has also announced its Natural Gas Delivery Plan, a 10-year strategic investment plan to deliver safe, reliable, clean, and affordable natural gas to customers. This plan includes accelerated infrastructure replacements, innovative leak detection technology, and process changes to reduce or eliminate methane emissions. The MPSC, FERC, other regulatory authorities, or other third parties may prohibit, delay, or impair the Natural Gas Delivery Plan and some or all of the associated capital investments. Consumers ability to implement its plan may be affected by environmental regulations, global supply chain disruptions, and changes in the cost, availability, and supply of natural gas or the ability to deliver natural gas to customers. Advancements in technology related to items such as renewable natural gas may not become commercially available or economically feasible as projected in Consumers plan. CMS Energy and Consumers could suffer financial loss, reputational damage, litigation, or other negative repercussions if they are unable to achieve their ambitious plans. Changes in taxation as well as the inherent difficulty in quantifying potential tax effects of business decisions could negatively impact CMS Energy and Consumers. CMS Energy and Consumers are required to make judgments regarding the potential tax effects of various financial transactions and results of operations in order to estimate their obligations to taxing authorities. The tax obligations include income taxes, real estate taxes, sales and use taxes, employment-related taxes, and ongoing issues related to these tax matters. The judgments include determining reserves for potential adverse outcomes regarding tax positions that have been taken and may be subject to challenge by the IRS and/or other taxing authorities. Unfavorable settlements of any of the issues related to these reserves or other tax matters at CMS Energy or Consumers could have a material adverse effect. Additionally, changes in federal, state, or local tax rates or other changes in tax laws could have adverse impacts. CMS Energy and its subsidiaries, including Consumers, must comply with the Dodd-Frank Act and its related regulations. The Dodd-Frank Act provides for regulation by the Commodity Futures Trading Commission of certain commodity-related contracts. Although CMS Energy, Consumers, and certain subsidiaries of NorthStar Clean Energy qualify for an end-user exception from mandatory clearing of commodity-related swaps, these regulations could affect the ability of these entities to participate in these markets and could add additional regulatory oversight over their contracting activities. CMS Energy and Consumers could incur substantial costs to comply with environmental requirements. CMS Energy and Consumers are subject to costly and stringent environmental regulations that will likely require additional significant capital expenditures for CCR disposal and storage, cooling water intake equipment, effluent treatment, and PCB remediation. In addition, regulatory action on PFAS at the state and/or federal level could cause CMS Energy and Consumers to further test and remediate some sites if PFAS is present at certain levels. Present and reasonably anticipated state and federal environmental statutes and regulations will continue to have a material effect on CMS Energy and Consumers. CMS Energy and Consumers have interests in fossil-fuel-fired power plants, other types of power plants, and natural gas systems that emit greenhouse gases. Federal, state, and local environmental laws and rules, as well as international accords and treaties, could require CMS Energy and Consumers to install additional equipment for emission controls, undertake heat-rate improvement projects, purchase carbon emissions allowances, curtail operations, invest in generating capacity with fewer carbon dioxide emissions, or take other significant steps to manage or lower the emission of greenhouse gases. Similarly, Table of Contents Consumers could be restricted from constructing natural gas infrastructure due to potential environmental regulations, which could require more costly alternatives. The following risks related to climate change, emissions, and environmental regulations could also have a material adverse impact on CMS Energy and Consumers: a change in regulators implementation of policy or litigation originated by third parties against CMS Energy or Consumers due to CMS Energys or Consumers greenhouse gas or other emissions or CCR disposal and storage impairment of CMS Energys or Consumers reputation due to their greenhouse gas or other emissions and public perception of their response to potential environmental regulations, rules, and legislation extreme weather conditions, such as severe storms or flooding, that may affect customer demand, company operations, or company infrastructure Consumers expects to collect fully from its customers, through the ratemaking process, expenditures incurred to comply with environmental regulations, but cannot guarantee this outcome. If Consumers were unable to recover these expenditures from customers in rates, CMS Energy or Consumers could be required to seek significant additional financing to fund these expenditures. For additional information regarding compliance with environmental regulations, see Item 1. BusinessCMS Energy and Consumers Environmental Strategy and Compliance and Item 7. Managements Discussion and Analysis of Financial Condition and Results of OperationsOutlook. CMS Energys and Consumers businesses could be affected adversely by any delay in meeting environmental requirements. A delay or failure by CMS Energy or Consumers to obtain or maintain any necessary environmental permits or approvals to satisfy any applicable environmental regulatory requirements or install emission or pollution control equipment could: prevent the construction of new facilities prevent the continued operation of and sale of energy from existing facilities prevent the suspension of operations at existing facilities prevent the modification of existing facilities result in significant additional costs CMS Energy and Consumers expect to incur additional substantial costs related to remediation of legacy environmental sites. Consumers expects to incur additional substantial costs related to the remediation of its former MGP sites and other response activity costs at a number of other sites, including, but not limited to, sites of retired coal-fueled electric generating units, under NREPA and CERCLA. Consumers believes these costs should be recoverable in rates, but cannot guarantee that outcome. Business/Operations Risks There are risks associated with Consumers substantial capital investment program planned for the next ten years. Consumers planned investments include the construction or acquisition of electric generation, electric and gas infrastructure, conversions and expansions, environmental controls, electric grid modernization Table of Contents technology, and other electric and gas investments to upgrade delivery systems, as well as decommissioning of older facilities. The success of these capital investments depends on or could be affected by a variety of factors that include, but are not limited to: effective pre-acquisition evaluation of asset values, future operating costs, potential environmental and other liabilities, and other factors beyond Consumers control effective cost and schedule management of new capital projects availability of qualified construction personnel, both internal and contracted changes in commodity and other prices, applicable tariffs, and/or material and equipment availability governmental approvals and permitting operational performance changes in environmental, legislative, and regulatory requirements regulatory cost recovery inflation of labor rates increases in lead times and disruptions in supply chain distribution barriers to accessing key materials for renewable projects (solar, battery, and other key equipment) created by geopolitical relations and U.S. relations with China It is possible that adverse events associated with these factors could have a material adverse effect on Consumers. CMS Energy and Consumers could be affected adversely by legacy litigation and retained liabilities. The agreements that CMS Energy and Consumers enter into for the sale of assets customarily include provisions whereby they are required to: retain specified preexisting liabilities, such as for taxes, pensions, or environmental conditions indemnify the buyers against specified risks, including the inaccuracy of representations and warranties that CMS Energy and Consumers make make payments to the buyers depending on the outcome of post-closing adjustments, litigation, audits, or other reviews, including claims resulting from attempts by foreign or domestic governments to assess taxes on past operations or transactions Many of these contingent liabilities can remain open for extended periods of time after the sales are closed. Depending on the extent to which the buyers might ultimately seek to enforce their rights under these contractual provisions, and the resolution of any disputes concerning them, there could be a material adverse effect on CMS Energys or Consumers liquidity, financial condition, and results of operations. Consumers is exposed to risks related to general economic conditions in its service territories. Consumers electric and gas utility businesses are affected by the economic conditions impacting the customers they serve. If the Michigan economy becomes sluggish or declines, Consumers could experience reduced demand for electricity or natural gas that could result in decreased earnings and cash flow. In addition, economic conditions in Consumers service territory affect its collections of accounts receivable and levels of lost or stolen gas. Table of

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Contents Consumers is exposed to changes in customer usage that could impact financial results. Technology advances, government incentives and subsidies, and recent regulatory decisions could increase the cost effectiveness of customer-owned methods of producing electricity and managing energy use resulting in reduced load, cross subsidization, and increased costs. Customers could also reduce their consumption through demand-side energy conservation and energy waste reduction programs. Similarly, customers could also reduce their consumption of natural gas through alternative technologies or fuels. CMS Energys and Consumers energy sales and operations are affected by seasonal factors and varying weather conditions from year to year. CMS Energys and Consumers utility operations are seasonal. The consumption of electric energy typically increases in the summer months, due primarily to the use of air conditioners and other cooling equipment, while peak demand for natural gas typically occurs in the winter due to colder temperatures and the resulting use of natural gas as heating fuel. Accordingly, CMS Energys and Consumers overall results may fluctuate substantially on a seasonal basis. Mild temperatures during the summer cooling season and winter heating season as well as the impact of extreme weather events on Consumers system could have a material adverse effect. CMS Energy and Consumers are subject to information security risks, risks of unauthorized access to their systems, and technology failures. In the regular course of business, CMS Energy and Consumers handle a range of sensitive confidential security and customer information. In addition, CMS Energy and Consumers operate in a highly regulated industry that requires the continued operation of sophisticated information and control technology systems and network infrastructure. Despite implementation of security measures, technology systems, including disaster recovery and backup systems, are vulnerable to failure, cyber crime, unauthorized access, and being disabled. These events could impact the reliability of electric generation and electric and gas delivery and also subject CMS Energy and Consumers to financial harm. Cyber crime, which includes the use of malware, computer viruses, and other means for disruption or unauthorized access against companies, including CMS Energy and Consumers, is increasing in frequency, scope, and potential impact. While CMS Energy and Consumers have not been subject to cyber incidents that have had a material impact on their operations to date, their security measures in place may be insufficient to prevent a major cyber incident in the future. If technology systems, including disaster recovery and backup systems, were to fail or be breached, CMS Energy and Consumers might not be able to fulfill critical business functions, and sensitive confidential and proprietary data could be compromised. In addition, because CMS Energys and Consumers generation, transmission, and distribution systems are part of an interconnected system, a disruption caused by a cyber incident at another utility, electric generator, system operator, or commodity supplier could also adversely affect CMS Energy or Consumers. A variety of technological tools and systems, including both company-owned information technology and technological services provided by outside parties, support critical functions. The failure of these technologies, including backup systems, or the inability of CMS Energy and Consumers to have these technologies supported, updated, expanded, or integrated into other technologies, could hinder their business operations. Table of Contents CMS Energys and Consumers businesses have liability risks. Consumers electric and gas delivery systems, power plants, gas infrastructure including storage facilities, wind energy or solar equipment, and energy products, and the independent power plants owned in whole or in part by CMS Energy could be involved in incidents, failures, or accidents that result in injury, loss of life, or property loss to customers, employees, or the public. Although CMS Energy and Consumers have insurance coverage for many potential incidents (subject to deductibles, limitations, and self-insurance amounts that could be material), depending upon the nature or severity of any incident, failure, or accident, CMS Energy or Consumers could suffer financial loss, reputational damage, and negative repercussions from regulatory agencies or other public authorities. CMS Energy and Consumers are subject to risks that are beyond their control, including but not limited to natural disasters, civil unrest, terrorist attacks and related acts of war, cyber incidents, vandalism, and other catastrophic events. Natural disasters, severe weather, wars, terrorist acts, civil unrest, vandalism, theft, cyber incidents, pandemics, and other catastrophic events could result in severe damage to CMS Energys and Consumers assets beyond what could be recovered through insurance policies (which are subject to deductibles, limitations, and self-insurance amounts that could be material), could require CMS Energy and Consumers to incur significant upfront costs, and could severely disrupt operations, resulting in loss of service to customers. There is also a risk that regulators could, after the fact, conclude that Consumers preparedness or response to such an event was inadequate and take adverse actions as a result. Energy risk management strategies might not be effective in managing fuel and electricity pricing risks, which could result in unanticipated liabilities to CMS Energy and Consumers or increased volatility in their earnings. CMS Energy and Consumers are exposed to changes in market prices for commodities including, but not limited to, natural gas, coal, electric capacity, electric energy, emission allowances, gasoline, diesel fuel, and RECs. CMS Energy and Consumers manage commodity price risk using established policies and procedures, and they may use various contracts to manage this risk, including swaps, options, futures, and forward contracts. No assurance can be made that these strategies will be successful in managing CMS Energys and Consumers risk or that they will not result in net liabilities to CMS Energy or Consumers as a result of future volatility. A substantial portion of Consumers operating expenses for its electric generating plants and vehicle fleet consists of the costs of obtaining these commodities. The contracts associated with Consumers fuel for electric generation and purchased power are executed in conjunction with the PSCR mechanism, which is designed to allow Consumers to recover prudently incurred costs associated with its positions in these commodities. If the MPSC determined that any of these contracts or related contracting policies were imprudent, recovery of these costs could be disallowed. Natural gas prices in particular have been historically volatile.

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Consumers routinely enters into contracts for natural gas to mitigate exposure to the risks of demand, market effects of weather, and changes in commodity prices associated with the gas distribution business. These contracts are executed in conjunction with the GCR mechanism, which is designed to allow Consumers to recover prudently incurred costs associated with its natural gas positions. If the MPSC determined that any of these contracts or related contracting policies were imprudent, recovery of these costs could be disallowed. CMS Energy and Consumers do not always hedge any or all of the exposure of their operations from commodity price volatility. Furthermore, the ability to hedge exposure to commodity price volatility depends on liquid commodity markets. As a result, to the extent the commodity markets are illiquid, Table of Contents CMS Energy and Consumers might not be able to execute their risk management strategies, which could result in larger unhedged positions than preferred at a given time. To the extent that unhedged positions exist, fluctuating commodity prices could have a negative effect on CMS Energy and Consumers. Changes in laws that limit CMS Energys and Consumers ability to hedge could also have a negative effect on CMS Energy and Consumers. Consumers might not be able to obtain an adequate supply of natural gas or coal, which could limit its ability to operate its electric generation facilities or serve its natural gas customers. Consumers has natural gas and coal supply and transportation contracts in place for the natural gas and coal it requires for its electric generating capacity. Consumers also has interstate transportation and supply agreements in place to facilitate delivery of natural gas to its customers. Apart from the contractual and monetary remedies available to Consumers in the event of a counterpartys failure to perform under any of these contracts, there can be no assurances that the counterparties to these contracts will fulfill their obligations to provide natural gas or coal to Consumers. The counterparties under the agreements could experience financial or operational problems that inhibit their ability to fulfill their obligations to Consumers. In addition, counterparties under these contracts might not be required to supply natural gas or coal to Consumers under certain circumstances, such as in the event of a natural disaster or severe weather. If Consumers were unable to obtain its supply requirements, it could be required to purchase natural gas or coal at higher prices, implement its natural gas curtailment program filed with the MPSC, or purchase replacement power at higher prices. Unplanned outages or maintenance could be costly for CMS Energy or Consumers. Unforeseen outages or maintenance of the electric and gas delivery systems, power plants, gas infrastructure including storage facilities and compression stations, wind energy or solar equipment, and energy products owned in whole or in part by CMS Energy or Consumers may be required for many reasons. When unplanned outages occur, CMS Energy and Consumers will not only incur unexpected maintenance expenses, but may also have to make spot market purchases of electric and gas commodities that may exceed CMS Energys or Consumers expected cost of generation or gas supply, be forced to curtail services, or retire a given asset if the cost or timing of the maintenance is not reasonable and prudent. Unplanned generator outages could reduce the capacity credit CMS Energy or Consumers receives from MISO and could cause CMS Energy or Consumers to incur additional capacity costs in future years. General Risk Factors The COVID-19 pandemic could materially and adversely affect each of CMS Energys and Consumers business, results of operations, financial condition, capital investment program, liquidity, and cash flows. The COVID19 pandemic has had widespread impacts on people, businesses, economies, and financial markets globally, in the U.S., and in markets where CMS Energy and Consumers conduct business. These impacts include a reduction in economic activity, disruption to supply chains and operations, increased labor costs, reduced availability of labor, and reduced productivity. CMS Energy and Consumers are exposed to counterparty risk. Adverse economic conditions or financial difficulties experienced by counterparties with whom CMS Energy and Consumers do business could impair the ability of these counterparties to pay for Table of Contents CMS Energys and Consumers services and/or fulfill their contractual obligations, including performance and payment of damages. CMS Energy and Consumers depend on these counterparties to remit payments and perform contracted services in a timely and adequate fashion. Any delay or default in payment or performance, including inadequate performance, of contractual obligations could have a material adverse effect on CMS Energy and Consumers. Volatility and disruptions in capital and credit markets could have a negative impact on CMS Energys and Consumers lenders, vendors, contractors, suppliers, customers, and other counterparties, causing them to fail to meet their obligations. CMS Energy and Consumers are exposed to significant reputational risks. CMS Energy and Consumers could suffer negative impacts to their reputations as a result of operational incidents, violations of corporate policies, regulatory violations, inappropriate use of social media, or other events. Reputational damage could have a material adverse effect and could result in negative customer perception and increased regulatory oversight. A work interruption or other union actions could adversely affect Consumers. At December 31, 2022, unions represent 42 percent of Consumers employees. Consumers union agreements expire in 2025. If these employees were to engage in a strike, work stoppage, or other slowdown, Consumers could experience a significant disruption in its operations and higher ongoing labor costs. Failure to attract and retain an appropriately qualified workforce could adversely impact CMS Energys and Consumers results of operations. In some areas, competition for skilled employees is high and if CMS Energy and Consumers were unable to match skill sets to future needs, they could encounter operating challenges and increased costs. These challenges could include a lack of resources, loss of knowledge, and delays in skill development. Additionally, higher costs could result from the use of contractors to replace employees, loss of productivity, and safety incidents. Failing to train replacement employees adequately and to transfer internal knowledge and expertise could adversely affect CMS Energys and Consumers ability to manage and operate their businesses.

Ticker: CEG, Sector: Utilities, Filed At: 2023-02-16T11:04:17-05:00

##TABLE_START ITEM 1. ##TABLE_ENDGeneral On February 21, 2021, the Board of Directors of Exelon Corporation (Exelon) authorized management to pursue a plan to separate its competitive generation and customer-facing energy businesses, conducted through Constellation Energy Generation, LLC (Constellation, formerly Exelon Generation Company, LLC) and its subsidiaries, into an independent, publicly traded company. Constellation Energy Corporation (CEG Parent or the Company), a Pennsylvania corporation and a direct, wholly owned subsidiary of Exelon, was newly formed for the purpose of separation and had not engaged in any activities except in preparation for the distribution. On February 1, 2022, Exelon completed the separation by distributing all the outstanding shares of the Companys common stock, on a pro rata basis to the holders of Exelons common stock, with the Company holding all the interests in Constellation previously held by Exelon (the "Separation"). As of 2002, Constellation has been an individual registrant since the registration of their public debt securities under the Securities Act. As an individual registrant, Constellation has historically filed consolidated financial statements to reflect their financial position and operating results as a stand-alone, wholly owned subsidiary of Exelon. Unless otherwise indicated or the context otherwise requires, references herein to the terms "we," "our," "us" and "the Company" refer collectively to CEG Parent and Constellation. See Glossary for defined terms. Our Business We are the nations largest producer of carbon-free energy and a leading supplier of energy products and services to businesses, homes, community aggregations and public sector customers across the continental United States, including three-fourths of Fortune 100 companies. Our generation fleet of nuclear, hydro, wind, natural gas, and solar generation facilities has the generating capacity to power the equivalent of 15 million homes, producing 11 percent of the carbon-free energy in the United States. Constellations fleet is helping to accelerate the nations transition to a carbon-free future with more than 32,355 megawatts of capacity and an annual output that is nearly 90 percent carbon-free. This makes us an important partner to businesses and state and local governments that are setting ambitious carbon-reduction goals and seeking long-term solutions to the climate crisis. We employ approximately 13,370 people, and do business in 48 states, the District of Columbia, Canada, and the United Kingdom. Our generation fleet produces more clean, carbon-free energy than any other company in the United States. We are committed to a clean energy future, and we believe our generation fleet is essential to helping meet clean energy targets, at both the state and national level. Our customer-facing business is one of the nation's largest competitive energy suppliers, offering innovative solutions along the sustainability continuum to meet customer clean energy and climate goals. Our Operations We operate the largest carbon-free generation fleet in the nation and are one of the largest competitive electric generation companies in the country, as measured by owned and contracted MWs. Collectively, the combined fleet is nearly 90% carbon-free (based on generation output of electricity) and is the fourth largest generation portfolio in the U.S. in terms of total generation with meaningful geographic diversity. At December 31, 2022, our generating resources consisted of the following: ##TABLE_START Type of Capacity MWs Owned generation assets (a) Nuclear 20,895 Natural gas and oil 8,807 Renewable (b) 2,653 Owned generation assets 32,355 Contracted generation (c) 3,883 Total generating resources 36,238 ##TABLE_END__________ (a) Net generation capacity is stated at proportionate ownership share. See ITEM 2. PROPERTIES for additional information. (b) Includes wind, hydroelectric, and solar generating assets. (c) Electric supply procured under unit-specific agreements. The following map illustrates the locations of our owned generation facilities as of December 31, 2022: The Company's Generation Fleet Map (a) Owned Assets (b) Nuclear Wind Gas/Other Solar Hydro __________ (a) Note: One symbol is included per location. Some locations may have multiple generating units. Locations in tight geographic proximity may appear as one symbol. Units that are not currently operational are not captured. (b) Does not reflect Grand Prairie Generating Station (Gas/Other), located in Alberta, Canada. We have five reportable segments, as described in the table below, representing the different geographical areas in which our owned generating resources are located and our customer-facing activities are conducted. ##TABLE_START Segment Net Generation Capacity (MWs) (a) % of Net Generation Capacity Geographical Area Mid-Atlantic 10,495 32 % Eastern half of PJM, which includes New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia, and parts of Pennsylvania and North Carolina Midwest 11,892 37 % Western half of PJM and the United States footprint of MISO, excluding MISOs Southern Region New York 3,093 10 % NYISO ERCOT 3,610 11 % Electric Reliability Council of Texas Other Power Regions 3,265 10 % New England, South, West, and Canada Total 32,355 100 % ##TABLE_END__________ (a) Net generation capacity is stated at proportionate ownership share as of December 31, 2022. See ITEM 2. PROPERTIES for additional information. The following table shows sources of electric supply in GWhs for 2022 and 2021: ##TABLE_START Source of Electric Supply 2022 2021 Nuclear (a)(b) 173,350 172,990 Purchases non-trading portfolio 70,682 67,605 Natural gas and oil 21,563 19,960 Renewable (c) 6,049 6,577 Total Supply 271,644 267,132 ##TABLE_END__________ (a) Includes the proportionate share of output where we have an undivided ownership interest in jointly-owned generating plants and includes the total output of plans that are fully consolidated. (b) 2021 values have been revised from those previously reported to correctly reflect our 82% undivided ownership interest in Nine Mile Point Unit 2. (c) Includes wind, hydroelectric, solar, and in 2021, biomass generating assets. See Note 2 Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information regarding the sale of our biomass facility. Nuclear Facilities Our nuclear fleet is the nations largest, with current generating capacity of approximately 21 gigawatts; it produced 173 terawatt hours of zero-emissions electricity during 2022 enough to power 15.4 million homes and avoid more than 123 million metric tons of carbon emissions according to the EPA GHG Equivalencies Calculator. We have ownership interests in 13 nuclear generating stations currently in service, consisting of 23 units. As of December 31, 2022, we wholly own all our nuclear generating stations, except for undivided ownership interests in four jointly owned nuclear stations: Quad Cities (75% ownership), Peach Bottom (50% ownership), Salem (42.59% ownership), and Nine Mile Point Unit 2 (82% ownership), which are consolidated in our consolidated financial statements relative to our proportionate ownership interest in each unit. See ITEM 2. PROPERTIES for additional information on our nuclear facilities. On August 6, 2021, Constellation and EDF entered into a settlement agreement pursuant to which we, through a wholly owned subsidiary, purchased EDFs equity interest in CENG, a joint venture with EDF, which wholly owned the Calvert Cliffs and Ginna nuclear stations and Nine Mile Point Unit 1, in addition to the 82% undivided ownership interest in Nine Mile Point Unit 2. Prior to August 6, 2021, we had a 50.01% membership interest in CENG, however CENG is consolidated within our results for all periods presented. See Note 2 Mergers, Acquisitions, and Dispositions and Note 22 Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for additional information regarding the acquisition of EDF's equity interest in CENG and the CENG consolidation. We operate all of these nuclear generating stations, except for the two units at Salem, which are operated by PSEG Nuclear, LLC (an indirect, wholly owned subsidiary of PSEG), and we have consistently operated our nuclear plants at best-in-class levels. During 2022, 2021, and 2020, our nuclear generating facilities achieved capacity factors (a) of 94.8%, 94.5%, and 95.4%, respectively, at ownership percentage. The nuclear capacity factor has been approximately four percentage points better than the industry average annually since 2013. Capacity factors, which are significantly affected by the number and duration of refueling and non-refueling outages, can have a significant impact on our results of operations. In 2022, we achieved an average refueling outage duration of 21 days for units we operate. We achieved an average refueling outage duration of 22 days in both 2021 and 2020, against industry averages of 32 and 34 days, respectively. We manage our scheduled refueling outages to minimize their duration and to maintain high nuclear generating capacity factors, resulting in a stable supply position for our wholesale and retail power marketing activities. In 2022, 2021, and 2020, electric supply (in GWhs) generated from our nuclear generating facilities was 64%, 65%, and 62%, respectively, of our total electric supply, which also includes natural gas, oil, and renewable generation and electric supply purchased for resale. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information on electric supply sources. During scheduled refueling outages, we perform maintenance and equipment upgrades in order to maintain safe, reliable operations and to minimize the occurrence of unplanned outages. In addition to the maintenance and equipment upgrades performed by us during scheduled refueling outages, we have extensive operating and security procedures in place to ensure the safe operation of our nuclear units. We also have extensive safety systems in place to protect the plant, personnel, and surrounding area in the unlikely event of an accident or other incident. We have original 40-year operating licenses from the NRC for each of our nuclear units and have received 20-year operating license renewals from the NRC for all our nuclear units except Clinton. PSEG has received 20-year operating license renewals for Salem Units 1 and 2. Peach Bottom has previously received a second 20-year license renewal from the NRC, for a total 80-year term, for Units 2 and 3. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information. __________ (a) Capacity factor is defined as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at full average annual mean capacity for that time period. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information. The following table summarizes the current license expiration dates for our nuclear facilities currently in service: ##TABLE_START Station Unit In-Service Date (a) Current License Expiration Braidwood 1 1988 2046 2 1988 2047 Byron 1 1985 2044 2 1987 2046 Calvert Cliffs 1 1975 2034 2 1977 2036 Clinton (b) 1 1987 2027 Dresden (b) 2 1970 2029 3 1971 2031 FitzPatrick 1 1975 2034 LaSalle 1 1984 2042 2 1984 2043 Limerick 1 1986 2044 2 1990 2049 Nine Mile Point 1 1969 2029 2 1988 2046 Peach Bottom (c) 2 1974 2033 3 1974 2034 Quad Cities 1 1973 2032 2 1973 2032 Ginna 1 1970 2029 Salem 1 1977 2036 2 1981 2040 ##TABLE_END__________ (a) Denotes year in which nuclear unit began commercial operations. (b) We are currently seeking license renewals for Clinton and Dresden Units 2 and 3 to extend the operating licenses by an additional 20 years. (c) In February 2022, the NRC issued an order related to its review of our subsequent license renewal application for Peach Bottom and the NRC directed its staff to change the expiration dates for the licenses back to 2033 and 2034. We expect that the license expiration dates will be restored to 2053 and 2054, respectively, See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information. The operating license renewal process takes approximately four years from commencement, which includes approximately two years for us to develop the application and approximately two additional years for the NRC to review the application. Depreciation provisions are based on the estimated useful lives of the stations, which generally correspond with the term of the NRC operating licenses denoted in the table above as of December 31, 2022, except for Clinton, Dresden and Peach Bottom. We are currently seeking license renewals for our Clinton and Dresden units. Clinton depreciation provisions are based on an estimated useful life through 2047. Dresden Units 2 and 3 depreciation provisions are based on an estimated useful life through 2049 and 2051, respectively, in anticipation of the license renewals. Peach Bottom Units 2 and 3 depreciation provisions are based on an estimated useful life through 2053 and 2054 respectively, in anticipation of the license expiration dates being restored. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information. From August 27, 2020 through September 15, 2021, Byron and Dresden depreciation provisions were accelerated to reflect the previously announced shutdown dates of September 2021 and November 2021, respectively. On September 15, 2021, we updated the estimated useful lives for both facilities to reflect the end of the current NRC operating license for each unit consistent with the table above. See Note 3 Regulatory Matters and Note 7 Early Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information on Byron and Dresden and the Illinois CMC program. Natural Gas, Oil and Renewable Facilities (including Hydroelectric) We operate approximately 11 gigawatts of natural gas, oil, hydroelectric, wind, and solar generation assets, which provide a mix of baseload, intermediate, and peak power generation. We wholly own all our natural gas, oil and renewable generating stations, except for: (1) Wyman 4; (2) certain wind project entities; and (3) CRP, which is owned 49% by another unrelated party. We operate all of these facilities, except for Wyman 4, which is operated by the principal owner, NextEra Energy Resources LLC, a subsidiary of NextEra Energy, Inc. See ITEM 2. PROPERTIES for additional information regarding these generating facilities and Note 22 Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for additional information regarding CRP, which is a VIE. In 2022, 2021, and 2020, electric supply (in GWhs) generated from our owned natural gas, oil, and renewable generating facilities was 10%, 10%, and 9%, respectively, of our total electric supply. Much of this output was dispatched to support our wholesale and retail power customer-facing activities. Our natural gas, oil and renewable fleet has similarly demonstrated a track record of strong performance with a power dispatch match (a) of

98.4%, 72.4%, and 98.4% and renewables energy capture (b) of 95.8%, 95.7%, and 93.4% in 2022, 2021, and 2020, respectively. Our power dispatch match performance in 2021 was significantly impacted by the February 2021 extreme weather event in Texas, refer to Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information. Natural gas, oil, wind and solar generation plants are generally not licensed, and, therefore, the decision on when to retire plants is, fundamentally, a commercial one. FERC has the exclusive authority to license most non-federal hydropower projects located on navigable waterways or federal lands, or connected to the interstate electric grid, which include our Conowingo Hydroelectric Project (Conowingo) and Muddy Run Pumped Storage Facility Project (Muddy Run). Muddy Run's license expires on December 1, 2055 and is currently being depreciated over the estimated useful life, which corresponds with the available license term. In March 2021, FERC issued a new 50-year license for Conowingo, vacated in December 2022 on remand, however depreciation provisions continue to assume an estimated useful life through 2071 in anticipation of the license expiration date being restored. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on Conowingo. On March 31, 2021 and June 30, 2021, we completed the sale of a significant portion of our solar business and our interest in the Albany Green Energy biomass facility, respectively. Note 2 Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on these dispositions. __________ (a) Dispatch Match is used to measure the responsiveness of a unit to the market, expressed as the total actual energy revenue net of fuel cost relative to the total desired energy revenue net of fuel cost. Factors having an adverse effect on Dispatch Match include forced outages, derates, and failure to operate to the desired generation signal. (b) Energy capture is an indicator of how efficiently the installed assets capture the natural energy available from the wind and the sun. Energy capture represents an energy-based fraction, the numerator of which is the energy produced by the sum of the wind turbines/solar panels in the year, and the denominator of which is the total expected energy to be produced during the year, with adjustments made for certain events that are considered non-controllable, such as force majeure events, serial design-manufacturing equipment failures, and transmission curtailments. Energy capture for the combined wind and solar fleet is weighted by the relative site projected pre-tax variable revenue. Contracted Generation In addition to energy produced by owned generation assets, we source electricity from generators we do not own under long-term contracts. The following tables summarize our long-term contracts to purchase unit-specific physical power with an original term in excess of one year in duration, by region, in effect as of December 31, 2022: ##TABLE_START Region Number of Agreements Expiration Dates Capacity (MWs) Mid-Atlantic 6 2023 - 2035 279 Midwest 3 2026 - 2032 351 New York 4 2023 26 ERCOT 6 2026 - 2035 841 Other Power Regions 12 2023 - 2037 2,386 Total 31 3,883 ##TABLE_END##TABLE_START 2023 2024 2025 2026 2027 Thereafter Total Capacity Expiring (MW) 140 101 490 398

5 2,749 3,883 ##TABLE_ENDCustomer-Facing Business We are one of the nations largest energy suppliers, through our integrated business operations we sell electricity, natural gas, and other energy-related products and solutions to various types of customers, including distribution utilities, municipalities, cooperatives, and commercial, industrial, public sector, and residential customers in markets across multiple geographic regions. We serve approximately 2 million total customers, including three-fourths of Fortune 100 companies, and approximately 1.6 million unique residential customers. We are a leader in electric power supply, serving approximately 208 TWhs in 2022 through sales to retail customers and wholesale load auctions to a diverse geographic customer base. The following table illustrates these volumes across our five reportable segments: 2022 Electric Power Supply (TWhs) Served Across Regions (a) __________ (a) Includes retail load and wholesale load auction volumes only. Electric generation in excess of our total retail and wholesale load would be marketed to the respective ISO in which our facility is located. Other includes New England, South, and West. We are active in all domestic wholesale power and gas markets that span the entire lower 48 states and have complementary retail activity across many of those states. We largely obtain physical power supply from our owned and contracted generation located in multiple geographic regions. The commodity risks associated with the output from owned and contracted generation are managed using various commodity transactions including sales to retail customers, trades on commodity exchanges, and sales to wholesale counterparties in accordance with our ratable hedging program. See further discussion of the ratable hedging program in the Price and Supply Risk Management section below. The main objective is to obtain low-cost energy supply to meet physical delivery obligations to both our wholesale and retail customers. Wholesale Market Our wholesale channel-to-market involves the sale of electricity among electric utilities and electricity marketers before it is eventually sold to end-use consumers. In 2022, we served approximately 65 TWhs of power load across competitive utility load procurement and bilateral sales to municipalities, co-ops, banks, and other wholesale entities. Complementary to our national portfolio, we have several decades of relationships with wholesale counterparties across all domestic power markets as a means of both monetizing our own generation, as well as sourcing contracted generation to meet customer and portfolio needs. With increased customer demand for sustainability, our ability to source contracted generation has provided a capital-light way for us to provide customers with the sustainable solutions they are demanding to support a cleaner energy ecosystem. This creates durable customer relationships and repeatable business through the ability to respond to customer and marketplace trends. Similarly, this contracting acumen provides the ability to supplement our native generation with other non-renewable assets to meet changing portfolio needs in a financially efficient manner. In our wholesale gas business we participate across all parts of the gas value chain, including trading, transport and storage and physical supply. Retail Market Retail competition in states across the U.S. range from full competition of energy suppliers for all retail customers (commercial,

industrial and residential) to partial retail competition available up to a capped amount for CI customers only. We are a leader in retail markets, serving approximately 143 TWhs of electric power retail load and 800 Bcf of gas in 2022, primarily to CI customers across multiple geographic regions in the U.S. Constellation Retail has a Diverse Geographic Footprint Strong customer relationships are a key part of our customer-facing business strategy. Retail customer renewal rates have been strong over the last six years across CI power customer groups, with an average contract term of approximately two years and customer duration of more than six years, with many customers well beyond these metrics. Specifically, we enjoyed renewal rates of 79% for CI power customers and 90% for CI gas customers in 2022, higher than the previous five years, owing to both our competitive pricing as well as our strong customer relationships. Our consistently high renewal rates are driven by our ability to provide customized solutions and delivering focused attention to our customers needs, resulting in industry-leading customer satisfaction. We are also successful at acquiring new customers by offering innovative services and products that meet their needs. In addition to our high customer renewal rates, we have produced consistently high new win rates for CI power as well, acquiring nearly one out of every three new customers who have chosen to shop with us over the past four years. High customer satisfaction levels, market expertise, stability and scale drive growth and result in historically proven business consistency and margins. While providing customers with the best possible price is a key focus, we leverage our broad suite of electric and gas product structures, oftentimes customized, to provide customers with the commodity solution and information that best fits their needs. It is this attention to the customer that creates the durable, repeatable value highlighted in these statistics. Consumer purchasing strategies have trended from direct supply relationships to third-party relationships with a number of customers looking to third-party consultants and brokers to find suppliers like us to reduce costs and evaluate the increasing number of options available for expanding energy solutions beyond the commodity. In response, we have expanded our third-party capabilities, created scale through a comprehensive support structure, and enhanced digital applications providing tools, tracking, and measurement, as well as the ability to extend the reach of our sustainability services and products to drive additional market share. While this trend of customers using third parties to find suppliers has slowed in recent years, we have remained the market leader in direct sales with over 32% of the CI market share of direct customer business driven by our highly experienced and long-tenor direct sales team. Energy Solutions As one of the largest customer-facing platforms in the U.S., we benefit from significant economies of scale, that allow us to provide our customers with competitively priced energy and to structure highly tailored solutions targeted to a customers unique power needs and clean energy goals. We partner with our customers to provide options along the sustainability continuum, including renewable, efficiency and technology solutions to meet their carbon-free energy goals. Our energy efficiency products provide the ability to optimize performance and maximize efficiency across customer facilities and operations through contract structures that include implementation of energy efficiency upgrades with no upfront capital requirements. Additionally, these service offerings provide scalable solutions to meet sustainability goals through investment across the life of the facility or operations and allow for budget certainty. The ongoing ability to optimize energy consumption for customers allows us to support customer demands with the right combination of technology and efficiency program options. Our CORe product serves CI customers' sustainability needs by matching contracted, third-party new-build renewable generation with customer desire to add additional carbon-free generation to the grid with geographic preference. In addition to larger-scale CORe offerings, we offer a range of sustainability solutions to customers (RECs, EFECs, RINs, RNG, carbon offsets, hourly carbon-free energy matching, etc.) to support their energy needs during the transition to a carbon-free energy ecosystem. In addition to sustainability products and services, data and analytics have also become increasingly important for our customers. Our smart utility expense management platform helps customers proactively manage utility costs, understand trends, and develop strategies to optimize spend and drive sustainability objectives. This platform provides new avenues for incremental growth by coupling the opportunities for customer usage optimization with accompanying products and solutions that we can provide to customers. These types of data and analytical services allow us to grow our customer base in previously inaccessible regulated markets by offering non-commodity energy-related products. Our Constellation Technology Ventures commercialization team invests in, and collaborates with, portfolio companies to deploy products and technologies across our broad customer base to drive value for both us and portfolio companies. Portfolio company solutions have included EV and charging infrastructure, sustainability monitoring and reporting tools, distributed energy resources, financing solutions, and more. Price and Supply Risk Management We use a combination of wholesale and retail customer load sales, as well as non-derivative and derivative contracts, all with credit-approved counterparties, to hedge the commodity price risk of the generation portfolio. For merchant generation sales not already hedged via comprehensive state programs, such as the CMC program in Illinois, we typically utilize a three-year ratable sales plan to align our hedging strategy with our financial objectives. The prompt three-year merchant sales are hedged on an approximate rolling 90%/60%/30% basis, providing cash flow stability while still allowing commercial opportunities to generate value for the Company. We may also enter transactions that are outside of this ratable hedging program. We are exposed to commodity price risk for the portions of our electricity portfolio that are unhedged. As of December 31, 2022, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York, and ERCOT reportable segments is 94%-97% and 75%-78% for 2023 and 2024, respectively. Similarly, the scale and scope of the portfolio provides risk-mitigating technology, product, and geographical diversification. We will continue to be proactive in using hedging strategies to mitigate commodity price volatility. The percentage of expected generation hedged is the number of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted generation based on a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all wholesale and retail load sales, as well as hedging products, which include economic hedges and certain non-derivative contracts. A portion of our hedging strategy may be implemented using fuel products based on assumed correlations between power and fuel prices. Our risk management group monitors the financial risks of the wholesale and retail power marketing activities. We also use financial and commodity contracts for proprietary trading purposes, but this activity accounts for only a small portion of our efforts and is not material to our results. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information. The cycle of production and utilization of nuclear fuel includes the mining and milling of uranium ore into uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride, the enrichment of the uranium hexafluoride, and the fabrication of fuel assemblies. Nuclear fuel assemblies are obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, including contracts sourced from Russia, and contracted fuel fabrication services. We have inventory in various forms and engage a diverse set of suppliers to ensure we can secure the nuclear fuel needed to continue to operate our nuclear fleet long-term and do not anticipate difficulty in obtaining the necessary uranium concentrates or conversion, enrichment, or fabrication services to meet the nuclear fuel requirements of our nuclear units. We manage various risks around our nuclear fuel requirements in accordance with our fuel procurement policy. The size of our inventory holdings and forward contractual coverage considers our refueling needs across multiple years to protect against supply disruptions and near-term price volatility, while allowing for capital flexibility. We engage a diverse set of domestic and international suppliers and limit our transactions with each supplier to mitigate concentration of risk. Refer to ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information. Natural gas is procured through long-term and short-term contracts, as well as spot-market purchases. Fuel oil inventories are managed so that in the winter months sufficient volumes of fuel are available in the event of extreme weather conditions and during the remaining months to take advantage of favorable market pricing. See ITEM 1A. RISK FACTORS, ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Critical Accounting Policies and Estimates and Note 16 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding derivative financial instruments. Seasonality Our operations are affected by weather, which affects demand for electricity and natural gas, as well as operating conditions. The market price for electricity is also affected by changes in the demand for electricity and the available supply of electricity. With respect to the electric business, very warm weather in summer months and, with respect to the electric and natural gas businesses, very cold weather in winter months is referred to as favorable weather conditions because those weather conditions result in increased deliveries of electricity and natural gas. Conversely, mild weather reduces demand. As a result, our operating results in the future may fluctuate substantially on a seasonal basis, especially when more severe weather conditions such as heat waves or extreme winter weather make such fluctuations more pronounced. The pattern of this fluctuation may change depending on the type and location of the facilities owned, the retail load served and the terms of contracts to purchase or sell electricity. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information. Insurance We are subject to liability, property damage, and other risks associated with major incidents at our generating stations. We have reduced our financial exposure to these risks through insurance, both property damage and liability, and other industry risk-sharing provisions. We also maintain business interruption insurance for our renewable projects, but not for our other generating stations unless required by contract or financing agreements. We are self-insured to the extent that any losses may exceed the amount of insurance maintained or are within the policy deductible for our insured losses. For additional information regarding property insurance, see ITEM 2. PROPERTIES, Note 17 Debt and Credit Agreements for additional information on financing agreements, and Note 19 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for insurance specific to our nuclear facilities. Regulation We are a public utility as defined under the Federal Power Act and are subject to FERCs exclusive ratemaking jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Under the Federal Power Act, FERC has the authority to grant or deny market-based rates for sales of energy, capacity, and ancillary services to ensure that such sales are just and reasonable. FERCs jurisdiction over ratemaking includes the authority to suspend the market-based rates of utilities and set cost-based rates should FERC find that its previous grant of market-based rates authority is no longer just and reasonable. Other matters subject to FERC jurisdiction include, but are not limited to, third-party financings; review of mergers; dispositions of jurisdictional facilities and acquisitions of securities of another public utility or an existing operational generating facility; affiliate transactions; intercompany financings and cash management arrangements; certain internal corporate reorganizations; and certain holding company acquisitions of public utility and holding company securities. RTOs and ISOs are FERC regulated entities that exist in several regions to provide transmission service across multiple transmission systems. FERC has approved PJM, MISO, ISO-NE, and SPP as RTOs and CAISO and NYISO as ISOs. These entities are responsible for regional planning, managing transmission congestion, developing wholesale markets for energy and capacity, maintaining reliability, market monitoring, the scheduling of physical power sales brokered through ICE and NYMEX, and the elimination or reduction of redundant transmission charges imposed by multiple transmission providers when wholesale customers take transmission service across several transmission systems. ERCOT is not subject to regulation by FERC but performs a similar function in Texas to that performed by RTOs in markets regulated by FERC. We are subject to the jurisdiction of the NRC with respect to the operation of our nuclear generating facilities, including the licensing for operation of each unit. The NRC subjects nuclear generating stations to continuing review and regulation covering, among other things, operations, maintenance, emergency planning, security, and environmental and radiological aspects of those stations. As part of its reactor oversight process, the NRC continuously assesses unit performance indicators and inspection results and communicates its assessment on a semi-annual basis. All nuclear generating stations operated by us are categorized by the NRC in the Licensee Response Column, which is the highest of five performance bands. The NRC may modify, suspend, or revoke operating licenses and impose civil penalties for failure to comply with the Atomic Energy Act or the terms of the operating licenses. Changes in regulations by the NRC may require a substantial increase in capital expenditures and/or operating costs for our nuclear generating facilities. NRC regulations also require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts at the end of the life of the facility to decommission the facility. The ultimate decommissioning obligation is expected to be funded by the NDT funds. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS Liquidity and Capital Resources; Critical Accounting Policies and Estimates, Nuclear Decommissioning Asset Retirement Obligations; and Note 3 Regulatory Matters, Note 10 Asset Retirement Obligations, and Note 18 Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial statements for additional information regarding our NDT funds and decommissioning obligations. Our operations are also subject to the jurisdiction of various other federal, state, regional, and local agencies, and federal and state environmental protection agencies. Additionally, we are subject to NERC mandatory reliability standards, which protect the nations bulk power system against potential disruptions from cyber and physical security breaches. Constellation's Strategy and Outlook Strategy We believe shareholder value is built on a foundation of operational excellence and the pairing of our majority carbon-free energy fleet with our customer-facing platform. We are committed to maintaining investment grade credit ratings. We are focused on optimizing cash returns through a disciplined approach to safe and efficient operations and cost management, underpinned by stable and durable margins from our customer-facing businesses and coupled with distinct payments to our generation plants for the clean energy attributes. We may pursue future growth opportunities that provide additional value building on our core businesses, or expanding our competitive advantages. We are committed to maintaining a strong balance sheet, returning value to our shareholders, and investing in clean energy and sustainable solutions. As environmental sustainability continues to build momentum for businesses across the country, the demand for carbon-free and sustainability solutions increases. We are committed to a carbon-free energy future and aim to serve as a partner to businesses and the federal, state and local governments that are setting ambitious carbon-reduction goals and seeking long-term solutions to the climate crisis. We will be a leading advocate at the federal level and in our states for policies that will reduce GHG emissions and preserve and grow clean energy. We are committed to reducing our GHG emissions and enabling our CI customers through the following: 1. Achieving a generation portfolio mix with 100% of our owned generation carbon-free by 2040, including an interim goal of 95% carbon-free by 2030, subject to policy support and technology advancements, 2. A 100% reduction of our operations-driven emissions by 2040, including an interim goal to reduce carbon emissions by 65% from 2020 levels by 2030 and reduce methane emissions 30% from 2020 by 2030, and 3. Providing 100% of CI customers with specific information about their GHG impact. The principles of our sustainable business strategy demonstrate our commitment to a carbon-free future while maintaining a strong balance sheet, advancing our ESG initiatives and investing in clean energy solutions. Power America's Clean Energy Future. We will operate and grow the nations largest fleet of clean, zero-emissions generation facilities, with world-class levels of safety, reliability and resiliency. Expand America's Largest Fleet of Clean Energy Centers. We will leverage and expand our state-of-the-art clean energy assets by exploring co-location of customer load, direct air capture of CO2, and producing clean hydrogen and other sustainable fuels to reduce industrial emissions. Uplift and Strengthen our Communities. We will advance respect, belonging, diversity and equity by driving community investment and creating family-sustaining clean energy jobs. Provide Energy and Sustainability Solutions for Customers. We will provide reliable, resilient energy and deliver innovative sustainability solutions that help customers achieve their clean energy goals. We are committed to maintaining sufficient financial liquidity and an appropriate capital structure to support safe, secure and reliable operations, even in volatile market conditions. We believe our investment grade credit rating is a competitive advantage and we intend to maintain our credit position and best-in-class balance sheet. In line with that commitment, available cash flow will first be used to meet investment grade credit targets, with incremental capital allocated towards disciplined growth and shareholder return. We will build upon a strong compliance and risk management foundation and recognize the critical role this serves in maximizing operational results. We will continue to manage cash flow volatility through prudent risk management strategies across our business. Growth Opportunities. We continually evaluate growth opportunities aligned with our businesses, assets, and markets leveraging our expertise in those areas and offering durable returns. We may pursue growth opportunities that optimize our core business or expand upon our strengths, including, but not limited to the following: Opportunistic carbon-free energy acquisitions, particularly nuclear plants with supportive policy, Create new value from the existing fleet through repowering, co-location and other opportunities, Grow sustainability products and services for our customers focused on clean energy, efficiency, storage and electrification; help our CI customers develop and meet sustainability targets, Produce clean hydrogen using our carbon-free fleet, Engagement with the technology and innovation ecosystem through continued partnerships with national labs, universities, startups, and research institutions, and Explore advanced nuclear technology for investment and participation via advisory services to maintain our leadership position as stewards of a carbon-free energy future. We will employ a disciplined approach to acquisitions that grow future cash flow and support strategic initiatives. We will also continue to evaluate asset and business divestitures to rationalize the portfolio and optimize cash proceeds. Various market, financial, regulatory, legislative and operational factors could affect our success in pursuing these strategies. We continue to assess infrastructure, operational, policy, and legal solutions to these issues. See ITEM 1A. RISK FACTORS for additional information. Outlook The U.S. energy sector is experiencing unprecedented changes that we believe will increase the demand for reliable, clean power generation and benefit our business. We believe our generation fleet, including our nuclear assets, is well-positioned to deliver reliable, clean power and benefit from growing demand for carbon-free electricity. Key drivers of increased demand for clean energy include: Governmental and corporate policies designed to accelerate the decarbonization of the economy, Policy support for nuclear energy sources that also enable energy security, reliability and diversification, Rapid electrification of the U.S. economy, and Evolving customer preferences favoring clean energy, choice and digitization. Policy Support for Decarbonization and Emerging Carbon-Free Technologies. Driven by societal concerns about climate change, governments, corporations, and investors are increasingly advocating for the reduction of GHG emissions across all sectors of the economy, with reduction of GHG emissions by the energy sector being a key focus. Governments at the international, national and state levels have established or are currently contemplating increasingly stringent policies that require the reduction of GHG emissions over time. Corporations have also adopted targets to reduce the carbon emissions in their business operations, spurred in part by demand from investors and customers for sustainable, environment-friendly business practices. These governmental and corporate policies support the retention and expansion of carbon-free generation and the development and use of clean fuels like hydrogen. We are committed to a clean energy future and we believe our business is well-positioned to benefit from growing policy support for decarbonization as our generation fleet is essential to helping meet climate goals at both the state and federal levels. Policy Support for Nuclear Energy. As decarbonization accelerates, we expect our generation fleet will continue to play a critical role in meeting baseload power needs. Nuclear energy is currently the largest source of zero emissions electricity in the U.S., accounting for over 50% of the nations carbon-free power and our nuclear plants are meaningful contributors to the clean energy mix in the states in which they operate. Through enactment of the nuclear PTC in the IRA, federal policymakers have recognized the need to ensure the continued operation of the nations nuclear power plants. This federal support builds on actions taken by states to support nuclear generation, driven by factors that include recognition by governments and policy makers that existing nuclear generation facilities are essential to meeting policy objectives on reduction of GHG emissions, the desire to support jobs and regional economies, and the need to ensure reliability and security of the electrical grid through resource diversity. A 2018 study by the Massachusetts Institute of Technology, The Future of Nuclear Energy in a Carbon-Constrained World, found that the costs of achieving transformational decarbonization targets would increase significantly without the contribution of nuclear power. As such, we plan to file applications to extend the licenses of our nuclear fleet to 80 years for our units that receive continued policy support for their long-term operation. Electrification of the U.S Economy. The push to significantly reduce or eliminate GHG emissions could lead to acceleration of the electrification of the U.S. economy, including electrification of transportation, industrial operations, heating and cooling, and appliances, which could materially increase demand for electricity. We expect widespread electrification, hydrogen production, and direct air capture could result in U.S. electricity demand to more than double from what it is today by 2050. Although EV sales in North America are well behind Europe and China, increased policy support through the IRA and other federal and state policies, together with an increasing number of EV offerings hitting the market over the next five years, will drive market share gains in the U.S. market. A 2022 Rhodium Group study forecasts that as much as 57% of light duty vehicles sold in 2030 will be electric. Electrification of industrial processes, commercial equipment and residential appliances that currently utilize gas and oil as a fuel source will also play a role in increasing the net demand for electricity. According to the International Energy Agency, heat makes up two-thirds of industrial energy demand, and almost one-fifth of global energy consumption, prompting efforts by energy companies and industrial manufacturers to electrify their thermal processes. For companies like us whose core competency is safely generating and serving electricity and related products to its customers, the increasing demand from electrification provides natural growth opportunities. Evolving Customer Preferences. Consumers are increasingly purpose-driven and knowledgeable of services that drive decarbonization, leading them to value the ability to be connected to and trace the source of their clean energy choices. Growing awareness of climate change and green energy helps drive customer interest in value-add services and products around their energy usage, such as residential rooftop solar, EV charging, smart, energy-efficient home technologies, and the ability to choose 100 percent clean power 24 hours a day, 365 days a year in competitive retail energy markets. Continuing innovation in the digitization of the broader economy will facilitate greater control and opportunities for customers and businesses to more frequently engage with their energy providers and become more knowledgeable of their energy choices, including the solutions we provide. Employees Engaged Workforce Our employees are our greatest assets. We strive to create a workplace that is diverse, inclusive, innovative, and safe for our employees. In order to provide the services and products that our customers expect, we must create the best teams and these teams must reflect the diversity of the communities that we serve. Therefore, we strive to attract highly qualified and diverse talent and routinely review our hiring, development and promotion practices to ensure we maintain equitable and bias free processes. We have undertaken our first employee engagement survey as a company and will use it and future surveys to help identify our successes and opportunities for growth. The survey results are shared with leaders at all levels and they are also part of action planning to increase engagement. Career Development We provide our employees with growth opportunities, competitive compensation and benefits, and a variety of education and development programs. We are committed to helping employees advance their skills and careers, largely through educational opportunities in technical, safety and business acumen areas. Additionally, we develop our employees through individual discussions, mentorship programs, continuous feedback, and evaluations. We understand that continued education leads to a more engaged, skilled, and productive workforce and we support our employees in their educational endeavors to attract and retain people who are committed to personal and professional development by offering tuition reimbursement for approved higher education, certification or licensing courses. Well-Being and Benefits We are committed to helping our employees maintain and improve their health and wellness, and we offer a wide range of benefits designed to help our employees thrive professionally and personally. We take a holistic approach to health and wellness, providing support for our employees physical health, mental well-being, family, as well as financial and legal strength. Community We are also committed to helping improve the quality of life for people in the communities where we live, work and serve. We provide opportunities for company-sponsored volunteerism and charitable matching gifts programs. Our employees donated $4.6 million to non-profit organizations and provided just over 80,000 volunteer hours in 2022. Next Generation of Talent We are also committed to exposing underrepresented and underserved individuals within our communities to career opportunities in the energy industry. Through internships and scholarships, university and veteran recruiting, STEM education and training programs, and partnerships with diverse talent organizations such as the Society of Women Engineers and the National Society of Black Engineers, we are committed to providing equitable access to professional development and opportunities for the next generation of our workforce. Major focus areas include: Creating educational and awareness opportunities within STEM and the trades through curriculum development, early engagement, and educational partnerships, Reducing or removing access and opportunity barriers faced by young people and underrepresented and underserved members of the community, and Deepening current and executing new approaches and partnerships with industry employers, nonprofits, and community groups to provide entry and advancement opportunities for work-ready adults and youth through upskilling and reskilling training efforts. Diversity Metrics The following table shows diversity metrics for all employees and management as of December 31, 2022: ##TABLE_START Metric All Employees Management (d) Female (a)(b) 2,889 474

People of Color (a)(b) 2,569 331 Aged 30 1,680 50 Aged 30-50 7,420 1,474 Aged 50 4,270 855 Within 10 years of retirement eligibility 5,724 1,197 Total Employees (c) 13,370 2,379 ##TABLE_END__________ (a) We conduct an annual analysis on gender and racial pay equity. We also review hiring and promotion processes to neutralize any unconscious bias and embed equal pay efforts into broader company-wide equity initiatives. These actions reflect our commitment to create an environment where all employees can thrive and advance as equal members of the workforce. (b) This is based on self-disclosed information. (c) Total employees represents the sum of the aged categories. (d) Management is defined as executive/senior level officials and managers as well as all employees who have direct reports and supervisory responsibilities. Turnover Rates As turnover is inherent, management succession planning is performed and tracked for all executives and critical key manager positions. Management frequently reviews succession planning to ensure we are prepared when positions become available. The table below shows the average turnover rate for all employees for the last three years of 2020 to 2022: ##TABLE_START All Retirement Age 4.30 % Voluntary 6.00 % Non-Voluntary 1.20 % ##TABLE_ENDCollective Bargaining Agreements Approximately 25% of employees participate in CBAs. The following table presents employee information, including information about CBAs, as of December 31, 2022: ##TABLE_START Total Employees Covered by CBAs Number of CBAs CBAs New and Renewed in 2022 (a) Total Employees Under CBAs New and Renewed in 2022 3,342 21 1 74 ##TABLE_END__________ (a) Does not include CBAs that were extended in 2022 while negotiations are ongoing for renewal. Environmental Matters and Regulation We are subject to comprehensive and complex environmental legislation and regulation at the federal, state, and local levels, including requirements relating to climate change, air and water quality, solid and hazardous waste, and impacts on species and habitats. Our Board of Directors is responsible for overseeing the management of environmental matters. We have a management team to address environmental compliance and strategy, including the CEO, our Sustainability and Climate Strategy team, and other members of senior management. Performance of those individuals directly involved in environmental compliance and strategy is reviewed and affects compensation as part of the annual individual performance review process. Our Board of Directors has delegated to its Nuclear Oversight Committee and the Corporate Governance Committee the authority to oversee our compliance with health, environmental, and safety laws and regulations and its strategies and efforts to protect and improve the quality of the environment, including our internal climate change and sustainability policies and programs, as discussed in further detail below. Climate Change Driven by societal concerns about climate change, governments, corporations, and investors are increasingly advocating for the reduction of GHG emissions across all sectors of the economy, with reduction of GHG emissions by the energy sector being a key focus. Governments at the international, national and state levels have established or are currently contemplating increasingly stringent policies that require the reduction of GHG emissions over time. Corporations have also adopted targets to reduce the carbon emissions in their business operations, spurred in part by demand from investors and customers for sustainable, environment-friendly business practices. Emerging technologies like storage and hydrogen are also helping to advance decarbonization. We believe our business is well-positioned to benefit from growing policy support for decarbonization. However, as detailed below, we also face climate change mitigation and transition risks as well as adaptation risks. Mitigation and transition risks include changes to the energy systems as a result of new technologies, changing customer expectations and/or voluntary GHG reduction goals, as well as local, state or federal regulatory requirements intended to reduce GHG emissions. Adaptation risk refers to risks to our facilities or operations that may result from changes in the physical climate, such as changes to temperatures, weather patterns and sea level rise. See ITEM 1A. RISK FACTORS for additional information. Climate Change Mitigation and Transition We support comprehensive federal climate legislation that addresses the climate crisis and would ensure the country meets the targets set by the Paris Climate Accord. Independent of additional legislation, we support the EPA moving forward with meaningful regulation of GHG emissions under the Clean Air Act. We currently are subject to, and may become subject to additional, federal and/or state legislation and/or regulations addressing GHG emissions. We are deliberately positioned as a low-carbon generation company. We have minimized GHG emitting assets in our portfolio and maximized carbon-free electric production such that our generation emissions intensity is already 80% less than 2005 levels in support of achieving economy-wide GHG emissions reduction goals. Our Scope 1 and 2 GHG emissions in 2021 were 8.3 million metric tons carbon dioxide equivalent, of which 8.0 million metric tons were from our natural gas and oil fueled generation fleet, significantly less than our peers with similar volume of power generation. We produce electricity predominantly from low and carbon-free generating facilities (such as nuclear, hydroelectric, natural gas, wind, and solar) and neither own nor operate any coal-fueled generating assets. Our natural gas and oil generating plants produce GHG emissions, most notably CO2. In addition, we sell natural gas t hrough our customer-facing business; and consumers use of such natural gas produces GHG emissions. However, our owned-asset emission intensity, or rate of carbon dioxide equivalent (CO2e) emitted per unit of electricity generated, is among the lowest in the industry. In 2022, we achieved a 94.8% percent capacity factor across our nuclear fleet and our ownership of 21 gigawatts of carbon-free generation capacity at 23 nuclear units produced 173 TWhs of electricity in 2022. The electric sector plays a key role in lowering GHG emissions across the rest of the economy. Electrication of other sectors such as transportation and buildings coupled with simultaneous decarbonization of electric generation is a key lever for emissions reductions. To support this transition, we are advocating for public policy supportive of vehicle electrification, investing in enabling infrastructure and technology, and supporting customer education and adoption. We also continue to explore other decarbonization opportunities, supporting pilots of emerging energy technologies and development of clean fuels. International Climate Change Agreements. At the international level, the United States is a party to the United Nations Framework Convention on Climate Change (UNFCCC). The Parties to the UNFCCC adopted the Paris Agreement at the 21st session of the UNFCCC Conference of the Parties (COP 21) on December 12, 2015. Under the Agreement, which became effective on November 4, 2016, the parties committed to try to limit the global average temperature increase and to develop national GHG reduction commitments. On November 4, 2020, the United States formally withdrew from the Paris Agreement, retracting its commitment to reduce domestic GHG emissions by 26%-28% by 2025 compared with 2005 levels. However, on January 20, 2021, President Biden accepted the Paris Agreement, which resulted in the United States formal re-entry on February 19, 2021. The United States has now set an economy-wide target of reducing its net GHG emissions by 50-52% below 2005 levels by 2030. The 2021 UNFCCC Conference of the Parties (COP26) and resulting Glasgow Climate Pact indicated important global support for the Paris Agreement and continued progress toward decarbonization. The most recent Conference of Parties (COP27) held in Sharm el-Sheikh, Egypt recommitted countries to their pledges in the Glasgow Climate Pact. Federal Climate Change Legislation. On August 16, 2022, the U.S. Congress passed and President Biden signed into law the Inflation Reduction Act of 2022, which, among other things, includes federal tax credits, certain of which are transferable or fully refundable, for clean energy technologies including existing nuclear plants and hydrogen production facilities. The Nuclear PTC recognizes the contributions of carbon-free nuclear power by providing a federal tax credit of up to $15 per MWh, subject to phase-out, beginning in 2024 and continuing through 2032. The Hydrogen PTC provides a 10-year federal tax credit of up to $3 per kilogram for clean hydrogen produced after 2022 from facilities that begin construction prior to 2033. Both the Nuclear and Hydrogen PTCs include adjustments for inflation. The Hydrogen PTC creates additional opportunities for our nuclear fleet to enable decarbonization of other industries through the production of clean hydrogen. With this policy support, we expect that many of our nuclear assets will operate through the end of the Nuclear PTC period. The U.S. Department of Treasury has begun the process of issuing guidance on the relevant tax provisions included in the legislation. Regulation of GHGs from Power Plants under the Clean Air Act. The EPAs 2015 Clean Power Plan (CPP) established regulations addressing carbon dioxide emissions from existing fossil-fired power plants under Clean Air Act Section 111(d). The CPPs carbon pollution limits could be met through shifting generation from higher-emitting units to lower- or zero-emitting units. In July 2019, the EPA published the Affordable Clean Energy rule, which repealed the CPP and replaced it with less stringent emissions guidelines based on heat rate improvement measures. We, as part of Exelon, together with a coalition of other electric utilities, filed a lawsuit in the U.S. Court of Appeals for the D.C. Circuit on September 6, 2019, challenging the Affordable Clean Energy rule as unlawful. On January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the Affordable Clean Energy Rule. On October 29, 2021, the U.S.

Supreme Court granted certiorari to examine the extent of the EPAs authority to regulate GHGs from power plants. The electric utilities coalition filed a brief and participated in oral argument before the U.S. Supreme Court. On June 30, 2022, the U.S. Supreme Court issued a decision holding that the EPA did not have the authority to require generation shifting from coal to natural gas and renewables to reduce sector-wide emissions, as it had done in CPP. The remainder of the litigation was remanded to the U.S. Court of Appeals for the D.C. Circuit and held in abeyance in light of forthcoming actions from the EPA. The EPA has indicated it will propose new GHG limits for power plants in April 2023 and finalize them in 2024. State Climate Change Legislation and Regulation. Many states in which we operate have state and regional programs to reduce GHG emissions and renewable and other portfolio standards, which impact the power sector and other sectors as well. 25 states and the District of Columbia have 100% clean energy targets, deep GHG reductions, or both, encompassing 53% of U.S residential electricity customers. See discussion below for additional information on renewable and other portfolio standards. As the nations largest generator of carbon-free electricity, our fleet supports these efforts to produce safe, reliable electricity with minimal GHGs. In 2019, New York enacted the Climate Leadership and Community Protection Act, which commits the state to achieving net zero emissions by 2050, with interim emission reduction and renewable energy requirements in 2030 and 2040. New Jerseys Energy Master Plan, released in 2020, provides a comprehensive roadmap for achieving the states goal of a 100% clean energy economy by 2050 and its Global Warming Response Acts stated GHG emissions reductions of 80% below 2006 levels by 2050. On September 15, 2021, Illinois Public Act 102-0662 was signed into law by the Governor of Illinois. The Clean Energy Law is designed to achieve 100% carbon-free power by 2045 to enable the states transition to a clean energy economy. The Clean Energy Law establishes decarbonization requirements for Illinois as well as programs to support the retention and development of emissions-free sources of electricity. Our nuclear plants are meaningful contributors to the clean energy mix in the states in which they operate. States may not be able to meet their zero-carbon goals without our nuclear plants, as our plants provide a significant portion of the current carbon-free power. Several states in which our nuclear facilities operate have established policies to support nuclear generation. The supportive policies are driven by several factors, including recognition by governments and policy makers that existing nuclear generation facilities are essential to meeting policy objectives on reduction of GHG emissions, the desire to support jobs and regional economies, and the need to ensure reliability and security of the electrical grid through resource diversity. These state-specific policies preserve the environmental attributes of our nuclear facilities, and include the following: ##TABLE_START Policy Name Year Enacted Nuclear Facilities Impacted Type of Program Year of Expiration New York Clean Energy Standard 2016 FitzPatrick, Ginna, and NMP ZEC 2029 Illinois Zero Emission Standard 2016 Clinton and Quad Cities ZEC 2027 New Jersey Clean Energy Legislation 2018 Salem ZEC 2025 Illinois Clean Energy

Law 2021 Byron, Braidwood, and Dresden CMC 2027 ##TABLE_ENDSee Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the New Jersey Clean Energy Legislation and the Illinois Clean Energy Law. Regional Greenhouse Gas Initiative. On July 1, 2022, Pennsylvania formally began participation in RGGI, joining Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont, and Virginia. The program requires most fossil fuel-fired power plants in the region to hold allowances, sold at auction or on the secondary market, for each ton of CO2 emissions. Non-emitting resources do not have to purchase or hold these allowances. Pennsylvanias participation in RGGI was accomplished through a PA DEP regulation that became effective on July 1, 2022 that was challenged in the Commonwealth Court of Pennsylvania, which has enjoined the state from implementing the regulation pending resolution of the proceeding. The Commonwealth Court of Pennsylvania heard oral arguments in November 2022 on the merits of the challenges to Pennsylvania entering RGGI. In the interim, the state has petitioned the Pennsylvania Supreme Court to vacate the lower courts injunction order. Briefing of the appeal was completed on December 4, 2022. On January 15, 2022, Governor Youngkin directed the Virginia Department of Environmental Quality to reevaluate the states participation in RGGI and begin a regulatory process to consider repeal of the regulations providing for RGGI participation. On September 26, 2022, the Virginia State Air Pollution Control Board published a Notice of Intended Regulatory Action seeking public comment on the proposed repeal of the states regulations implementing its participation in RGGI. This matter remains pending. Renewable and Clean Energy Standards. 31 states and the District of Columbia, incorporating most of the states where we operate, have adopted some form of renewable or clean energy procurement requirement. These standards impose varying levels of mandates for procurement of renewable or clean electricity (the definition of which varies by state) and/or energy efficiency. These are generally expressed as a percentage of annual electric load, often increasing by year. Load serving entities comply with these various requirements through purchasing qualifying renewables, acquiring sufficient certificates (e.g., RECs), paying an alternative compliance payment, and/or a combination of these compliance alternatives. While we cannot predict the nature of future regulations or how such regulations might impact future financial statements, we have a low emission portfolio, and GHG restrictions would likely benefit our zero- and low-emission generating units relative to other higher-emission fossil fuel-fired generating units. Corporate Clean Energy Targets. Corporations are facing increasing pressure from their customers and investors to align their businesses with international and national environmental and sustainability objectives, including supporting goals to reduce GHG emissions in their business operations. Leading institutional investors and money managers are increasingly considering sustainability as a key factor in investment decisions and are increasingly advocating for more transparency in disclosure on climate-related matters and pledging to align proxy voting to climate-rated proposals with its fiduciary duty. An increasing number of corporations are also proactively making commitments to reducing their GHG emissions footprint, either through procuring increasing amounts of clean energy or RECs to offset their carbon footprint over time. As the nations largest producer of carbon-free energy, we support taking bold action to address the climate crisis and reestablish leadership in both emerging technologies and existing clean infrastructure that together will power the future. Emerging Carbon-Free Technologies. Emerging carbon-free technologies like storage and hydrogen are expected to help accelerate the economys decarbonization. Lower costs, state-directed mandates, a backlog of storage projects in the interconnection queue, and utilities seeking large-scale storage capacity to support higher renewables penetration have created conditions for rapid growth of this technology in the U.S. Clean hydrogen also has the potential to drive decarbonization, particularly as it relates to more challenging sectors like long-haul transportation, steel, chemicals, heating, agriculture, and long-term power storage. Nuclear power can be used to produce clean hydrogen, and our nuclear fleet positions us well to explore this emerging space. Both energy storage and clean hydrogen continue to gain political and business support and are expected to help support net-zero carbon goals. Climate Change Adaptation Our facilities and operations are subject to the global impacts of climate change. Long-term shifts in climactic patterns, such as sustained higher temperatures and sea level rise, may present challenges for our facilities and services. We believe our operations could be significantly affected by the physical risks of climate change. See ITEM 1A. RISK FACTORS, for additional information. We conduct seasonal readiness reviews at our power plants to ensure availability of fuel supplies and equipment performance before entering the summer and winter seasons and we consider and review national climate assessments to inform our longer-term planning. Our nuclear fleet is resilient to weather extremes and generates emissions-free electricity 24 hours a day even during unexpectedly cold winter events and hot summer events. Other Environmental Regulation Air Quality Mercury and Air Toxics Standards (MATS). In 2011, the EPA signed a final rule, known as MATS, to reduce emissions of hazardous air pollutants from power plants. MATS requires coal-fired power plants to achieve high removal rates of mercury, acid gases, and other metals, and to make capital investments in pollution control equipment and incur higher operating expenses. In 2016, in response to a U.S. Supreme Court decision requiring the EPA to consider costs in determining whether it was appropriate and necessary to regulate power plant emissions of hazardous air pollutants, the EPA issued a supplemental finding that, after considering costs, it remained appropriate and necessary. On May 22, 2020, the EPA reversed course, publishing a final rule revoking the "appropriate and necessary" finding underpinning MATS. A lawsuit in the D.C. Circuit sought vacatur of MATS based on the EPAs May 22, 2020 finding; on September 11, 2020, the Court granted a motion by Exelon and two other entities to intervene in that lawsuit to defend MATS, and on September 28, 2020, the Court held this portion of the litigation in abeyance. On July 21, 2020, we, as part of Exelon, and two other entities filed a lawsuit in the D.C. Circuit challenging the EPAs May 22, 2020 rescission of the appropriate and necessary finding. On January 20, 2021, President Biden issued an Executive Order directing the EPA to reconsider its May 22, 2020, revised supplemental finding, and the EPA subsequently moved for the D.C. Circuit to place the cases challenging that finding in abeyance pending its reconsideration, which the court did on February 21, 2021. On February 9, 2022 the EPA published a proposal to revoke the 2020 revised supplemental finding and reaffirm that it is "appropriate and necessary" to regulate hazardous air pollutant emissions from coal- and oil-fired power plants. Additionally, in February 2022, the D.C. Circuit granted unopposed motions to substitute Constellation in place of Exelon in these cases. The EPA has indicated that they will issue the final regulation in March 2023. If the EPA promulgates a final rule revoking the 2020 revised supplemental finding determination, then the cases currently before the D.C. Circuit concerning MATS may be dismissed as moot or placed in abeyance pending the disposition of any petitions for review that may be filed challenging that final rule. We cannot reasonably predict the outcome of this matter. Good Neighbor Rule. On April 6, 2022, the EPA published a proposed rule called Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards also known as the "Good Neighbor Rule" or the "Transport Rule". The proposed rule, among other things, established nitrogen oxides emissions budgets requiring fossil fuel-fired power plants in 25 states to participate in an allowance-based ozone season trading program beginning in 2023. Comments on the proposed rule were due June 6, 2022 and the EPA has indicated it will issue a final rule in early 2023. When the EPA finalizes this proposed rule, there may be impacts on the electric power market. We cannot reasonably predict the outcome of this rule. Oil and Gas Methane Rule . On December 6, 2022, the EPA published a supplemental proposed rule setting methane emissions standards for certain new and existing oil and gas facilities. The supplemental proposal updates the proposed regulation issued in November 2021. Comments on the proposed regulation were due on February 13, 2023. When the EPA finalizes this proposed rule, there may be indirect impacts on the electric power market through the supply of gas. We cannot reasonably predict the outcome of this rule. Water Quality Under the federal Clean Water Act, NPDES permits for discharges into waterways are required to be obtained from the EPA or from the state environmental agency to which the permit program has been delegated, and permits must be renewed periodically. Certain of our facilities discharge water into waterways and are therefore, subject to these regulations and operate under NPDES permits. Clean Water Act Section 316(b) is implemented through the NDPES program and requires that the cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts. Our power generation facilities with cooling water intake systems are subject to the EPAs Section 316(b) regulations finalized in 2014; the regulations requirements have been or will be addressed through renewal of these facilities NPDES permits. Until the compliance requirements are determined by the applicable state permitting director on a site-specific basis for each plant, we cannot estimate the effect that compliance with the

EPAs 2014 rule will have on the operation of our generating facilities and our consolidated financial statements. Should a state permitting director determine that a facility must install cooling towers to comply with the rule, that facilitys economic viability could be called into question. However, the final rule does not mandate cooling towers and allows state permitting directors to require alternative, less costly technologies and/or operational measures, based on a site-specific assessment of the feasibility, costs, and benefits of available options. On July 28, 2016, the NJDEP issued a final permit for Salem that did not require the installation of cooling towers and allows Salem to continue to operate utilizing the existing cooling water system with certain required system modifications. However, the permit is being challenged by an environmental organization, and if successful, could result in additional costs for Clean Water Act compliance. Potential cooling water system modification costs could be material and could adversely impact the economic competitiveness of this facility. Under Clean Water Act Section 404 and state laws and regulations, we may be required to obtain permits for projects involving dredge or fill activities in Waters of the United States. Where our facilities are required to secure a federal license or permit for activities that may result in a discharge to covered waters, we may be required to obtain a state water quality certification for those facilities under Clean Water Act section 401. We are also subject to the jurisdiction of the Delaware River Basin Commission and the Susquehanna River Basin Commission, regional agencies that primarily regulate water usage. Solid and Hazardous Waste and Environmental Remediation CERCLA authorizes response to releases or threatened releases of hazardous substances into the environment. CERCLA authorities complement those of the RCRA, which primarily regulates ongoing hazardous waste handling and disposal. Under CERCLA, generators and transporters of hazardous substances, as well as past and present owners and operators of hazardous waste sites, are strictly, jointly and severally liable for the cleanup costs of hazardous substances at sites, many of which are listed by the EPA on the National Priorities List. These PRPs can be ordered to perform a cleanup, can be sued for costs associated with an EPA-directed cleanup, may voluntarily settle with the EPA concerning their liability for cleanup costs, or may voluntarily begin a site investigation and site remediation under state oversight. Most states have also enacted statutes that contain provisions substantially like CERCLA. Such statutes apply in many states where we currently own or operate, or previously owned or operated facilities, including Illinois, Maryland, New Jersey, and Pennsylvania. In addition, RCRA governs treatment, storage and disposal of solid and hazardous wastes and cleanup of sites where such activities were conducted. Our operations have in the past, and may in the future, require substantial expenditures in order to comply with these federal and state environmental laws. Under these laws, we may be liable for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances generated or transported by us. We own or lease several real estate parcels, including parcels on which our operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. We are, or could become in the future, parties to proceedings initiated by the EPA, state agencies, and/or other responsible parties under CERCLA and RCRA or similar state laws with respect to several sites or may undertake to investigate and remediate sites for which we may be subject to enforcement actions by an agency or third-party. As of December 31, 2022, we have established appropriate contingent liabilities for environmental remediation requirements. In addition, we may be required to make significant additional expenditures not presently determinable for other environmental remediation costs. See Note 3 Regulatory Matters and Note 19 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding our environmental matters, remediation efforts, and related impacts to our Consolidated Financial Statements. Nuclear Waste Storage and Disposal There are no facilities for the reprocessing or permanent disposal of SNF currently in operation in the United States, nor has the NRC licensed any such facilities. We currently store all SNF generated by our nuclear generating facilities on-site in storage pools or in dry cask storage facilities. Since our SNF storage pools generally do not have sufficient storage capacity for the life of the respective plant, we have developed dry cask storage facilities to support operations. As of December 31, 2022, we had approximately 91,500 SNF assemblies (22,400 tons) stored on site in SNF pools or dry cask storage that includes SNF assemblies at Zion Station, for which we retain ownership and responsibility for the decommissioning of the Zion Independent Spent Fuel Storage Installation. All our nuclear sites have on-site dry cask storage. On-site dry cask storage in concert with on-site storage pools will be capable of meeting all current and future SNF storage requirements at each of our sites for the duration of both current and subsequent license periods of all stations and through decommissioning. For a discussion of matters associated with our contracts with the DOE for the disposal of SNF, see Note 19 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements. As a by-product of their operations, nuclear generating units produce LLRW. LLRW is accumulated at each generating station and permanently disposed of at licensed disposal facilities. The Federal Low-Level Radioactive Waste Policy Act of 1980 provides that states may enter into agreements to provide regional disposal facilities for LLRW and restrict use of those facilities to waste generated within the region. Illinois and Kentucky have entered into such an agreement, although neither state currently has an operational site, and none is anticipated to be operational for the next ten years. We ship our Class A LLRW, which represents 93% of LLRW generated at our stations, to disposal facilities in Utah and South Carolina, which have enough storage capacity to store all Class A LLRW for the duration of both current and subsequent license periods for all the stations in our nuclear fleet. The disposal facility in South Carolina at present is only receiving LLRW from LLRW generators in South Carolina, New Jersey (which includes Salem), and Connecticut. We utilize on-site storage capacity at all our stations to store and stage for shipping Class B and Class C LLRW. We have a contract through 2040 to ship Class B and Class C LLRW to a disposal facility in Texas. The agreement provides for disposal of all Class B and Class C LLRW currently stored at each station as well as the Class B and Class C LLRW generated during the term of the agreement. However, because the production of LLRW from our nuclear fleet will exceed the capacity at the Texas site (3.9 million curies for 15 years beginning in 2012), we will still be required to utilize on-site storage at our stations for Class B and Class C LLRW. We currently have enough storage capacity to store all Class B and Class C LLRW for the duration of both current and subsequent license periods for of all the stations in our nuclear fleet and, we continue to pursue alternative disposal strategies for LLRW, including an LLRW reduction program to minimize on-site storage and cost impacts. Corporate Information CEG Parents principal executive office is located at 1310 Point Street, Baltimore, Maryland 21231-3380. Constellations principal executive office is located at 200 Exelon Way, Kennett Square, Pennsylvania 19348-2473. The telephone number for our principal executive offices is (833) 883-0162. We maintain a website located at www.ConstellationEnergy.com. The information contained on, or accessible from, our website is not part of this annual report by reference or otherwise. Available Information We file our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and all amendments to those reports with the SEC. You may obtain copies of these documents by accessing the SECs website at www.sec.gov. In addition, as soon as reasonably practicable after such materials are furnished to the SEC, we make copies of these documents available to the public free of charge through our website or by contacting our corporate secretary at the applicable address set forth above under "Corporate Information." ITEM 1A. RISK FACTORS ##TABLE_ENDWe operate in a complex market and regulatory environment that involves significant risks, many of which are beyond our direct control. Such risks, which could negatively affect our consolidated financial statements, fall primarily under the categories below: Risks related to market and financial factors primarily include: the price of fuels, in particular the price of natural gas, which affects power prices, the generation resources in the markets in which we operate, our ability to operate our generating assets, our ability to access capital markets, the impacts of on-going competition, and emerging technologies and business models, including those related to climate change mitigation and transition to a low-carbon economy. Risks related to legislative, regulatory, and legal factors primarily include changes to, and compliance with, the laws and regulations that govern: the design of power markets, the renewal of permits and operating licenses, environmental and climate policy, and tax policy. Risks related to operational factors primarily include: changes in the global climate could produce extreme weather events, which could put our facilities at risk, and such changes could also affect the levels and patterns of demand for energy and related services, the safe, secure and effective operation of our nuclear facilities and the ability to effectively manage the associated decommissioning obligations, the ability of energy transmission and distribution companies to maintain the reliability, resiliency and safety of their energy delivery systems, which could affect our ability to deliver energy to our customers and affect our operating costs, and physical and cyber security risks for us as an owner-operator of generation facilities and as a participant in commodities trading. Risks related to our separation from Exelon primarily include: challenges to achieving the benefits of separation, including the need to replicate certain services provided by Exelon (e.g. information technology), which will require additional resources and expense, performance by Exelon and us under the transaction agreements, including indemnification responsibilities tied to the allocation of businesses and liabilities, and limitations on future capital-raising or strategic transactions during the two-year period following the distribution arising from the need to protect the tax-free treatment of the distribution. Risks Related to Market and Financial Factors We are exposed to price volatility associated with both the wholesale and retail power markets and the procurement of nuclear, natural gas and oil. We are exposed to commodity price risk for natural gas and the unhedged portion of our generation portfolio. Our earnings and cash flows are therefore exposed to variability of spot and forward market prices in the markets in which we operate. Price of Fuels. The spot market price of electricity for each hour is generally determined by the marginal cost of supplying the next unit of electricity to the market during that hour. Thus, the market price of power is affected by the market price of the marginal fuel used to generate the electricity unit. Cost of Fuel. We depend on nuclear fuel, natural gas and oil to operate most of our generating facilities. The supply markets for nuclear fuel, natural gas and oil are subject to price fluctuations, availability restrictions, counterparty default, and geopolitical risk, including the current Russia and Ukraine conflict and the potential for additional United States sanctions against Russia. The cycle of production and utilization of nuclear fuel is complex, and we engage a diverse set of suppliers to ensure we can secure the nuclear fuel needed to continue to operate our nuclear fleet long-term. Non-performance by these suppliers could have a material adverse impact on our consolidated financial statements. See ITEM 1. BUSINESS Price and Supply Risk Management and See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information on the nuclear fuel cycle and procurement. Demand and Supply. The market price for electricity is also affected by changes in the demand for electricity and the available supply of electricity. Unfavorable economic conditions, milder than normal weather, and the growth of energy efficiency and demand response programs can depress demand. In addition, in some markets, the supply of electricity can exceed demand during some hours of the day, resulting in loss of revenue for base-load generating plants such as our nuclear plants. Conversely, new demand sources such as electrification of transportation could increase demand and change demand patterns. Retail Competition. Our retail operations compete for customers in a competitive environment, which affects the margins we can earn and the volumes we are able to serve. In periods of sustained low natural gas and power prices and low market volatility, retail competitors can aggressively pursue market share because the barriers to entry can be low and wholesale generators (including us) use their retail operations to hedge generation output. Market Designs. The wholesale markets vary from region to region with distinct rules, practices and procedures. Changes in these market rules, problems with rule implementation, or failure of any of these markets could adversely affect our business. In addition, a significant decrease in market participation could affect market liquidity and have a detrimental effect on market stability. We may be adversely affected by the effects of sustained inflation. The existence of inflation in the economy has resulted in, or may result in, higher interest rates and capital costs, increased costs of labor, and other similar effects. If inflation rates continue to rise or remain elevated for a sustained period, they could have a material adverse effect on our business, financial condition, results of operations and liquidity. Although we may take measures to mitigate the impact of inflation, those measures may not be effective. We are potentially affected by emerging technologies that could over time affect or transform the energy industry. Advancements in power generation technology, including commercial and residential solar generation installations and commercial micro turbine installations, are improving the cost-effectiveness of customer self-supply of electricity. Improvements in energy storage technology, including batteries and fuel cells, could also better position customers to meet their around-the-clock electricity requirements. Improvements in energy efficiency of lighting, appliances, equipment and building materials will also affect energy consumption by customers. Changes in power generation, storage, and use technologies could have significant effects on customer behaviors and their energy consumption. These developments could affect the price of energy, levels of customer-owned generation, customer expectations and current business models and make portions of our generation facilities uneconomic prior to the end of their useful lives. These technologies could also result in further declines in commodity prices or demand for delivered energy. Each of these factors could affect our consolidated financial statements through, among other things, reduced operating revenues, increased operating and maintenance expenses, increased capital expenditures, and potential asset impairment charges or accelerated depreciation and decommissioning expenses over shortened remaining asset useful lives. Market performance and other factors could decrease the value of our NDT funds and employee benefit plan assets, which then could require significant additional funding. Disruptions in the capital markets and their actual or perceived effects on particular businesses and the broader economy could adversely affect the value of the investments held within our NDTs and employee benefit plan trusts. We have significant obligations in these areas and hold substantial assets in these trusts to meet those obligations. The asset values are subject to market fluctuations and will yield uncertain returns, which could fall below our projected return rates. A decline in the market value of the NDT fund investments could increase our funding requirements to decommission our nuclear plants. A decline in the market value of the pension and OPEB plan assets would increase the funding requirements associated with our pension and OPEB plan obligations. Additionally, our pension and OPEB plan liabilities are sensitive to changes in interest rates. As interest rates decrease, the liabilities increase, potentially increasing benefit costs and funding requirements. Changes in demographics, including increased numbers of retirements or changes in life expectancy assumptions or changes to Social Security or Medicare eligibility requirements could also increase the costs and funding requirements of the obligations related to the pension and OPEB plans. See Note 10 Asset Retirement Obligations and Note 15 Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information. We could be negatively affected by unstable capital and credit markets and increased volatility in commodity markets. We rely on the capital markets, particularly for publicly offered debt, as well as the banking and commercial paper markets, to meet our financial commitments and short-term liquidity needs. Disruptions in the capital and credit markets in the United States or abroad could negatively affect our ability to access the capital markets or draw on our bank revolving credit facilities. The banks may not be able to meet their funding commitments to us if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests within a short period of time. The inability to access capital markets or credit facilities, and longer-term disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could result in the deferral of discretionary capital expenditures, affect our ability to effectively hedge our generation portfolio, require changes to our hedging strategy in order to reduce collateral posting requirements, or require a reduction in discretionary uses of cash. In addition, we have exposure to worldwide financial markets, including Europe, Canada and Asia. Disruptions in these markets could reduce or restrict our ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of December 31, 2022, approximately 38%, 13%, and 19% of our available credit facilities were with European, Canadian and Asian banks, respectively. The strength and depth of competition in energy markets depend heavily on active participation by multiple trading parties, which could be negatively affected by disruptions in the capital and credit markets and legislative and regulatory initiatives that could affect participants in commodities transactions. Reduced capital and liquidity and failures of significant institutions that participate in the energy markets could diminish the liquidity and competitiveness of energy markets that are important to our business. Perceived weaknesses in the competitive strength of the energy markets could lead to pressures for greater regulation of those markets or attempts to replace market structures with other mechanisms for the sale of power, including the requirement of long-term contracts. If we were to experience a downgrade in our credit ratings to below investment grade or otherwise fail to satisfy the credit standards in our agreements with our counterparties or regulatory financial requirements, we would be required to provide significant amounts of collateral that could affect our liquidity and we could experience higher borrowing costs. Our business is subject to credit quality standards that could require market participants to post collateral for their obligations upon a decline in ratings. We are also subject to certain financial requirements under NRC regulations as a result of our operation of nuclear power plants that could require us to provide cash collateral or surety bonds if those requirements are not met. One or both events could adversely affect available liquidity and, in the case of a rating downgrade, borrowing and credit support costs. See ITEM 7.MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS Liquidity and Capital Resources Credit Matters and Cash Requirements Security Ratings for additional information regarding the potential impacts of credit downgrades on our cash flows. If we fail to meet project-specific financing agreement requirements, we could experience an impairment or loss of the financed project. We have project-specific financing arrangements and must meet the requirements of various agreements relating to those financings. Failure to meet those arrangements could give rise to a project-specific financing default which, if not cured or waived, could result in the specific project being required to repay the associated debt or other borrowings earlier than otherwise anticipated, and if such repayment were not made, the lenders or security holders would generally have broad remedies, including rights to foreclose against the project assets and related collateral or to force our subsidiaries in the project-specific financings to enter into bankruptcy proceedings. The impact of bankruptcy could result in the impairment of certain project assets. See Note 17 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information. Our risk management policies cannot fully eliminate the risk associated with our commodity trading activities. Our asset-based power position as well as our power marketing, fuel procurement and other commodity trading activities expose us to risks of commodity price movements. We buy and sell energy and other products and enter financial contracts to manage risk and hedge various positions in our portfolio. We are exposed to volatility in financial results for unhedged positions as well as the risk of ineffective hedges. We attempt to manage this exposure through enforcement of established risk limits and risk management procedures. These risk limits and risk management procedures may not work as planned and cannot eliminate all risks associated with these activities. Even when our policies and procedures are followed, and decisions are made based on projections and estimates of future performance, results of operations could be diminished if the judgments and assumptions underlying those decisions prove to be incorrect. Factors, such as future prices and demand for power, natural gas and other energy-related commodities, become more difficult to predict and the calculations become less reliable the further into the future estimates are made. As a result, we cannot predict the impact that our commodity trading activities and risk management decisions could have on our consolidated financial statements. Financial performance and load requirements could be negatively affected if we are unable to effectively manage our power portfolio. A significant portion of our power portfolio is used to provide power under procurement contracts with load serving entities and other customers. To the extent portions of the power portfolio are not needed for that purpose, our output is sold in the wholesale power markets. To the extent our power portfolio is not sufficient to meet the requirements of our customers under the related agreements, we must purchase power in the wholesale power markets. Our financial results could be negatively affected if we are unable to cost-effectively meet the load requirements of our customers, manage our power portfolio or effectively address the changes in the wholesale power markets. The impacts of significant economic downturns (i.e. recession) could lead to decreased volumes delivered and increased expense for uncollectible customer balances. The impacts of significant economic downturns on our retail customers, such as less demand for products and services provided by commercial and industrial customers, could result in an increase in the number of uncollectible customer balances and related expense. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information on our credit risk. Our results were negatively affected by the impacts of COVID-19 in 2020 and future pandemics or other significant health issues could also adversely affect our results. COVID-19 has previously disrupted economic activity in our markets and negatively affected our results of operations. The estimated impact of COVID-19 to our Net income was approximately $170 million for the year ended December 31, 2020 and was not material for the years ended December 31, 2021 and 2022. Any future widespread pandemic or other local or global health issue could adversely affect customer demand and our ability to operate our generation assets. We could be negatively affected by the impacts of weather. Our operations are affected by weather, which impacts demand for electricity and natural gas, the price of energy commodities, as well as operating conditions. To the extent that weather is warmer in the summer or colder in the winter than assumed, we could require greater resources to meet our contractual commitments. Extreme weather conditions or storms have affected the availability of generation and its transmission, limiting our ability to source or send power to where it is sold, and have also impaired the transportation of natural gas to our generating assets and our ability to supply natural gas to our customers. In addition, drought-like conditions limiting water usage could impact our ability to run certain generating assets at full capacity. These conditions, which cannot be accurately predicted, could cause us to seek additional capacity at a time when markets are weak. Climate change projections suggest increases to summer temperature and humidity trends, as well as more erratic precipitation and storm patterns over the long term in the areas where we have generation assets. The frequency in which weather conditions emerge outside the current expected climate norms could contribute to the weather-related impacts discussed above. Beginning on February 15, 2021, our Texas-based generating assets within the ERCOT market, specifically Colorado Bend II, Wolf Hollow II, and Handley, experienced periodic outages as a result of historically severe cold weather conditions. As a result of this weather event, we incurred a loss of approximately $800 million for the year ended December 31, 2021. By comparison, the estimated impact reduced our overall Net loss by approximately $50 million for the year ended December 31, 2022, see Note 3 Regulatory Matters and Note 19 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information. Long-lived assets and other assets could become impaired. Long-lived assets principally, generation assets represent the single largest asset class on our Consolidated Balance

Sheets. We evaluate the recoverability of the carrying value of long-lived assets to be held and used whenever events or circumstances indicating a potential impairment may exist. Factors such as, but not limited to, the business climate, including current and future energy and market conditions, environmental regulation, and the condition of assets are considered. An impairment would require us to reduce the carrying value of the long-lived asset to fair value through a non-cash charge to expense by the amount of the impairment. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS Critical Accounting Policies and Estimates, Note 8 Property, Plant, and Equipment and Note 12 Asset Impairments of the Combined Notes to Consolidated Financial Statements for additional information on long-lived asset impairments. We could incur substantial costs in the event of non-performance by third-parties under indemnification agreements. We are exposed to other credit risks in the power markets that are beyond our control. We have entered into various agreements with counterparties that require those counterparties to reimburse us and hold us harmless against specified obligations and claims. To the extent that any of these counterparties are affected by deterioration in their creditworthiness or the agreements are otherwise determined to be unenforceable, we could be held responsible for the obligations. We have issued indemnities to third parties regarding environmental or other matters in connection with purchases and sales of assets, including several of the Exelon utilities in connection with our absorption of their former generating assets. We could incur substantial costs to fulfill our obligations under these indemnities. In the bilateral markets, we are exposed to the risk that counterparties that owe us money or are obligated to purchase energy or fuel from us, will not perform under their obligations for operational or financial reasons. In the event the counterparties to these arrangements fail to perform, we could be forced to purchase or sell energy or fuel in the wholesale markets at less favorable prices and incur additional losses, to the extent amounts, if any, were already paid to the counterparties. In the spot markets, we are exposed to risk as a result of default sharing mechanisms that exist within certain markets, primarily RTOs and ISOs. We are also a party to agreements with entities in the energy sector that have experienced rating downgrades or other financial difficulties. In addition, our retail sales subject us to credit risk through competitive electricity and natural gas supply activities to serve commercial and industrial companies, governmental entities and residential customers. Retail credit risk results when customers default on their contractual obligations. This risk represents the loss that could be incurred due to the nonpayment of a customers account balance, as well as the loss from the resale of energy previously committed to serve the customer. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the February 2021 extreme cold weather event and Texas-based generating asset outages. Risks Related to Legislative, Regulatory, and Legal Factors Federal or state legislative or regulatory actions could negatively affect the scope and functioning of the wholesale markets. Approximately 70% of our generating resources, which include directly owned assets and capacity obtained through long-term contracts, are in the area encompassed by PJM. Our future results of operations are impacted by (1) FERCs and PJM's level of support for policies that favor the preservation of competitive wholesale power markets and recognize the value of carbon-free electricity and resiliency and for states' energy objectives and policies and (2) the absence of material changes to market structures that would limit or otherwise negatively affect us. Market rules in other regions could affect us in a similar fashion. We could also be affected by state laws, regulations or initiatives to subsidize existing or new generation. FERCs requirements for market-based rate authority could pose a risk that we may no longer satisfy FERCs tests for market-based rates. A loss of market-based rate authority would mean that we would sell power at cost-based rates. Our business is highly regulated and could be negatively affected by legislative and/or regulatory actions. Substantial aspects of our business are subject to comprehensive federal or state legislation and/or regulation. Our consolidated financial statements are significantly affected by our sales and purchases of commodities at market-based rates, as opposed to cost-based or other similarly regulated rates and federal and state regulatory and legislative developments related to emissions, climate change, capacity market mitigation, energy price information, resilience, fuel diversity and RPS. Federal or state legislative and regulatory efforts to preserve the environmental attributes and reliability benefits of zero-emission nuclear-powered generating facilities could be subject to legal and regulatory challenges and, if overturned, could result in the early retirement of certain of our nuclear plants. See Note 3 Regulatory Matters and Note 7 Early Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information. Fundamental changes in regulations or other adverse legislative actions affecting our business would require changes in our business planning models and operations. We cannot predict when or whether legislative and regulatory proposals could become law or what their effect would be. NRC actions could negatively affect the operations and profitability of our nuclear generating fleet. Regulatory Risk. A change in the Atomic Energy Act or the applicable regulations or licenses could require a substantial increase in capital expenditures or could result in increased operating or decommissioning costs. Events at nuclear plants owned by others, as well as those owned by us, could cause the NRC to initiate such actions. Spent Nuclear Fuel Storage. The approval of a national repository for the storage of SNF and the timing of that facility opening, will significantly affect the costs associated with storage of SNF and the ultimate amounts received from the DOE to reimburse us for these costs. Any regulatory action relating to the timing and availability of a repository for SNF could adversely affect our ability to decommission fully our nuclear units. We cannot predict whether a fee may be established or to what extent, in the future for SNF disposal. See Note 19 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information. We could be subject to higher costs and/or penalties related to mandatory reliability standards. We, as a user of the bulk power transmission system, are subject to mandatory reliability standards promulgated by NERC and enforced by FERC. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with or changes in the reliability standards could subject us to higher operating costs and/or increased capital expenditures. If we were found in non-compliance with the federal and state mandatory reliability standards, we could be subject to remediation costs as well as sanctions, which could include substantial monetary penalties. We could incur substantial costs to fulfill our obligations related to environmental and other matters. We are subject to extensive environmental regulation and legislation by local, state and federal authorities. These laws and regulations affect the way we conduct our operations and make capital expenditures, including how we handle air and water emissions, hazardous and solid waste, and activities affecting surface waters, groundwater, and aquatic and other species. Violations of these requirements could subject us to enforcement actions, capital expenditures to bring existing facilities into compliance, additional operating costs for remediation and clean-up costs, civil penalties and exposure to third parties claims for alleged health or property damages or operating restrictions to achieve compliance. In addition, we are subject to liability under these laws for the remediation costs for environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances we generated or released. Also, we are currently involved in several proceedings relating to sites where hazardous substances have been deposited and could be subject to additional proceedings in the future. See ITEM 1. BUSINESS Environmental Matters and Regulation and Note 19 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information. We could be negatively affected by federal and state RPS and/or energy conservation legislation, along with energy conservation by customers. Changes to current state legislation or the development of federal legislation that requires the use of clean, renewable and alternate fuel sources could significantly impact us. The impact could include reduced use of some of our generating facilities with effects on our operating revenues and costs. Federal and state legislation mandating the implementation of energy conservation programs and new energy consumption technologies could cause declines in customer energy consumption and lead to a decline in our operating revenues. See ITEM 1. BUSINESS Environmental Matters and Regulation Renewable and Clean Energy Standards and We are potentially affected by emerging technologies that could over time affect or transform the energy industry above for additional information. Our financial performance could be negatively affected by risks arising from our ownership and operation of hydroelectric facilities. FERC has the exclusive authority to license most non-federal hydropower projects located on navigable waterways, federal lands or connected to the interstate electric grid. If FERC does not issue new operating licenses for our hydroelectric facilities in the future or a station cannot be operated through the end of its current operating license, our results of operations could be adversely affected by increased depreciation rates and accelerated future decommissioning costs, since depreciation rates and decommissioning cost estimates are currently based on the available license term for each facility. We could also lose operating revenues and incur increased purchased power and fuel expense to meet our supply commitments. In addition, conditions could be imposed as part of the license renewal process that could adversely affect operations, require a substantial increase in capital expenditures, result in increased operating costs or render the project uneconomic. Similar effects could result from a change in the Federal Power Act or the applicable regulations due to events at hydroelectric facilities owned by others, as well as those owned by us. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding the license renewal for the Conowingo hydroelectric project. We could be negatively affected by challenges to tax positions taken, tax law changes and the inherent difficulty in quantifying potential tax effects of business decisions. We are required to make judgments in order to estimate our obligations to taxing authorities. These tax obligations include income, real estate, sales and use and employment-related taxes and ongoing appeal issues related to these tax matters. These judgments include reserves established for potential adverse outcomes regarding tax positions that have been taken that could be subject to challenge by the tax authorities. See Note 1 Basis of Presentation and Note 14 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information. Legal proceedings could result in a negative outcome, which we cannot predict. We are involved in legal proceedings, claims and litigation arising from our business operations. The material ones are summarized in Note 3 Regulatory Matters and Note 19 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements. Adverse outcomes in these proceedings could require significant expenditures, result in lost revenue, or restrict existing business activities. We could be subject to adverse publicity and reputational risks, which make us vulnerable to negative customer perception and could lead to increased regulatory oversight or other consequences. We could be the subject of public criticism. Adverse publicity of this nature could render public service commissions and other regulatory and legislative authorities less likely to view energy companies in a favorable light, and could cause those companies, including us, to be susceptible to less favorable legislative and regulatory outcomes, as well as increased regulatory oversight and more stringent legislative or regulatory requirements. Risks Related to Operational Factors We are subject to risks associated with climate change. Climate adaptation risk refers to risks to our facilities or operations that may result from changes in the physical climate, such as changes to temperatures, weather patterns and sea level rise. We periodically perform analyses to better understand how climate change could affect our facilities and operations. We primarily operate in the Midwest and East Coast of the United States, areas that have historically been prone to various types of severe weather events, and as such we have well-developed response and recovery programs based on these historical events. However, our physical facilities could be placed at greater risk of damage should changes in the global climate impact temperature and weather patterns, and result in more intense, frequent and extreme weather events, unprecedented levels of precipitation, sea level rise, increased surface water temperatures, and/or other effects. Over time, we may need to make additional investments to protect our facilities from physical climate-related risks. In addition, changes to the climate may impact levels and patterns of demand for energy and related services, which could affect our operations. Over time, we may need to make additional investments to adapt to changes in operational requirements as a result of climate change. Climate mitigation and transition risks include changes to the energy systems as a result of new technologies, changing customer expectations and/or voluntary GHG goals, as well as local, state or federal regulatory requirements intended to reduce GHG emissions. We also periodically perform analyses of potential pathways to reduce power sector and economy-wide GHG emissions to mitigate climate change. To the extent additional GHG reduction regulation or legislation becomes effective at the federal and/or state levels, we could incur costs to further limit the GHG emissions from our operations or otherwise comply with applicable requirements. To the extent such additional regulation or legislation does not become effective, the potential competitive advantage offered by our low-carbon emission profile may be reduced. See ITEM 1. BUSINESS Environmental Matters and Regulation Climate Change for additional information. Our financial performance could be negatively affected by matters arising from our ownership and operation of nuclear facilities. Nuclear capacity factors. Capacity factors for nuclear generating units significantly affect our results of operations. Lower capacity factors could decrease our revenues and increase operating costs by requiring us to produce additional energy from our natural gas and oil fueled facilities or purchase additional energy in the spot or forward markets in order to satisfy our supply obligations to committed third-party sales. These sources generally have higher costs than we incur to produce energy from our nuclear stations. Nuclear refueling outages. In general, refueling outages are planned to occur once every 18 to 24 months. The total number of refueling outages, along with their duration, could have a significant impact on our results of operations. When refueling outages last longer than anticipated or we experience unplanned outages, capacity factors decrease, and we face lower margins due to higher energy replacement costs and/or lower energy sales and higher operating and maintenance costs. Nuclear fuel quality. The quality of nuclear fuel utilized by us could affect the efficiency and costs of our operations. Remediation actions could result in increased costs due to accelerated fuel amortization, increased outage costs and/or increased costs due to decreased generation capabilities. Operational risk. Operations at any of our nuclear generation plants could degrade to the point where we must shut down the plant or operate at less than full capacity. If this were to happen, identifying and correcting the causes could require significant time and expense. We could choose to close a plant rather than incur the expense of restarting it or returning the plant to full capacity. In either event, we could lose revenue and incur increased purchased power and fuel expense to meet supply commitments. Further, our nuclear operations produce various types of nuclear waste materials, including SNF. The approval of a national repository for the storage of SNF and the timing of that facility opening, will significantly affect the costs associated with storage of SNF and the ultimate amounts received from the DOE to reimburse us for these costs. Any regulatory action relating to the timing and availability of a repository for SNF could adversely affect our ability to decommission fully our nuclear units. We cannot predict whether in the future a fee for SNF disposal may be reestablished or to what extent. If we are required to arrange for the safe and permanent disposal of spent fuel beyond current expectations, this could lead to substantial expense or capital expenditures. For plants operated but not wholly owned by us, we could also incur liability to our co-owners. For nuclear plants not operated and not wholly owned by us, from which we receive a portion of the plants output, our results of operations are dependent on the operational performance of the operators and could be adversely affected by a significant event at those plants. Additionally, poor operating performance at nuclear plants not owned by us could result in increased regulation and reduced public support for nuclear-fueled energy. Closure of generating plants owned by others, or extended interruptions of generating plants or failure of transmission lines, could adversely affect transmission systems and the sale and delivery of electricity in markets served by us. Nuclear major incident risk and insurance. The consequences of a major incident could be severe and include loss of life and property damage. Any resulting liability from a nuclear plant major incident within the United States, owned or operated by us or owned by others, could exceed our resources, including insurance coverage. We are a member of an industry mutual insurance company, NEIL, which provides property and accidental outage insurance for our nuclear operations. Uninsured losses and other expenses, to the extent not recovered from insurers or the nuclear industry, could be borne by us. Additionally, an accident or other significant event at a nuclear plant within the United States or abroad, whether owned by us or others, could result in increased regulation and reduced public support for nuclear-fueled energy. As required by the Price-Anderson Act, we carry the maximum available amount of nuclear liability insurance, $450 million for each operating site. Claims exceeding that amount are covered through mandatory participation in a financial protection pool. In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay claims exceeding the $13.7 billion limit for a single incident. See Note 19 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information of nuclear insurance. Decommissioning obligation and funding. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in certain minimum amounts at the end of the life of the facility to decommission the facility. Actual costs to decommission our nuclear facilities may substantially exceed our estimates as a result of changes in the approach and timing of decommissioning activities, changes in decommissioning costs, changes in federal or state regulatory requirements, other changes in our estimates or ability to effectively execute on our planned decommissioning activities. We make contributions to certain trust funds of the former PECO units based on amounts being collected by PECO from its customers and remitted to us. While we, through PECO, have recourse to collect additional amounts from PECO customers (subject to certain limitations and thresholds), we have no recourse to collect additional amounts from utility customers for any of our other nuclear units if there is a shortfall of funds necessary for decommissioning. If circumstances changed such that there was an inability to continue to make contributions to the trust funds of the former PECO units based on amounts collected from PECO customers, or if we no longer had recourse to collect additional amounts from PECO customers if there was a shortfall of funds for decommissioning, the adequacy of the trust funds related to the former PECO units could be negatively affected. Any changes to the PECO regulatory agreements could impact our ability to offset decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income, and the impact to our consolidated financial statements could be material. Should the expected value of the NDT fund for any former ComEd unit fall below the amount of the expected decommissioning obligation for that unit, the accounting to offset decommissioning-related activities for that unit may be temporarily suspended or discontinued, and the decommissioning-related activities would be recognized in the Consolidated Statements of Operations and Comprehensive Income, the impact of which could be material. For the year ended December 31, 2021, a pre-tax charge of $193 million was recorded in the Consolidated Statements of Operations and Comprehensive Income for decommissioning-related activities that were not offset for the Byron units due to contractual offset being temporarily suspended. Forecasting trust fund investment earnings and costs to decommission nuclear generating stations requires significant judgment, and actual results could differ significantly from current estimates. If the investments held by our NDT funds are not sufficient to fund the decommissioning of our nuclear units, we could be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that current and future NRC minimum funding requirements are met. See Note 10 Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information. We are subject to physical security and cybersecurity risks. We face physical security and cybersecurity risks. Threat sources continue to seek to exploit potential vulnerabilities in the electric generation and natural gas industry associated with protection of sensitive and confidential information, grid infrastructure and other energy infrastructures. These attacks and disruptions, both physical and cyber, are becoming increasingly sophisticated and dynamic. Continued implementation of advanced digital technologies increases the potentially unfavorable impacts of such attacks. We expect these attacks and disruptions to continue to occur in the future and we are constantly managing efforts to infiltrate and compromise our physical assets and information technology systems and data. A security breach, including physical or electronic break-ins, computer viruses, malware, attacks by hackers, ransomware attacks, phishing attacks, supply chain attacks, breaches due to employee error or misconduct and other similar breaches, of our physical assets or information systems, or those of our competitors, vendors, business partners and interconnected entities in RTOs and ISOs, or regulators could impact the operation of the generation fleet and/or reliability of the transmission and distribution system or result in the theft or inappropriate release of certain types of information, including critical infrastructure information, sensitive customer, vendor and employee data, trading or other confidential data. The risk of these system-related events and security breaches occurring continues to intensify, and while we have not directly experienced a material breach or disruption to our network or information systems or our operations to-date, such attacks continue to increase in sophistication and frequency, and we may be unable to prevent all such attacks in the future. If a significant breach were to occur, our reputation could be negatively affected, customer confidence in us or others in the industry could be diminished, or we could be subject to legal claims, loss of revenues, increased costs or operations shutdown. Moreover, the amount and scope of insurance maintained against losses resulting from any such events or security breaches may not be sufficient to cover losses or otherwise adequately compensate for any disruptions to business that could result. Furthermore, in the future, such insurance may not be available on commercially reasonable terms, or at all. In addition, new or updated security regulations or unforeseen threat sources could require changes in current measures taken by us or our business operations and could adversely affect our consolidated financial statements. Our employees, contractors, customers and the general public could be exposed to a risk of injury due to the nature of the energy industry. Employees and contractors throughout the organization work in, and the general public could be exposed to, potentially dangerous environments near our operations. As a result, employees, contractors and the general public are at some risk for serious injury, including loss of life. These risks include, but are not limited to, nuclear accidents, dam failure, gas explosions, and electric contact cases. Natural disasters, war, acts and threats of terrorism, pandemic and other significant events could negatively impact our results of operations, ability to raise capital and future growth. Our fleet of power plants and the transmission infrastructure to which they are connected could be affected by natural disasters and extreme weather events, which could result in increased costs, including supply chain costs. Natural disasters and other significant events increase our risk that the NRC or other regulatory or legislative bodies could change the laws or regulations governing, among other things, operations, maintenance, operating licenses, decommissioning, SNF storage, insurance, emergency planning, security and environmental and radiological matters. In addition, natural disasters could affect the availability of a secure and economical supply of water in some locations, which is essential for our continued operation, particularly the cooling of generating units. The impact that potential terrorist attacks could have on the industry and on us is uncertain. We face a risk that our operations would be direct targets or indirect casualties of an act of terror. Any retaliatory military strikes or sustained military campaign could affect our operations in unpredictable ways, such as changes in insurance markets and disruptions of fuel supplies and markets, particularly uranium and oil. Furthermore, these catastrophic events could compromise the physical or cybersecurity of our facilities, which could adversely affect our ability to manage our business effectively. Instability in the financial markets as a result of terrorism, war, natural disasters, pandemic, credit crises, recession or other factors also could result in a decline in energy consumption or interruption of fuel or the supply chain. In addition, the implementation of security guidelines and measures has resulted in and is expected to continue to result in increased costs. We could be significantly affected by the outbreak of a pandemic. We have plans in place to respond to a pandemic. However, depending on the severity of a pandemic and the resulting impacts to workforce and other resource availability, the ability to operate our generating assets could be adversely affected. In addition, we maintain a level of insurance coverage consistent with industry practices against property, casualty and cybersecurity losses subject to unforeseen occurrences or catastrophic events that could damage or destroy assets or interrupt operations. However, there can be no assurance that the amount of insurance will be adequate to address such property and casualty losses. Our business is capital intensive, and our assets could require significant expenditures to maintain and are subject to operational failure, which could result in potential liability. Our business is capital intensive and requires significant investments in electric generating facilities. Equipment, even if maintained in accordance with good utility practices, is subject to operational failure, including events that are beyond our control, and could require significant expenditures to remedy. Our consolidated financial statements could be negatively affected if we were unable to effectively manage our capital projects or raise the necessary capital. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS Liquidity and Capital Resources for additional information regarding our potential future capital expenditures. Our performance could be negatively affected if we fail to attract and retain an appropriately qualified workforce. Certain events, such as the separation transaction, an employee strike, loss of employees, loss of contract resources due to a major event, and an aging workforce without appropriate replacements, could lead to operating challenges and increased costs for us. The challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, could arise. We are particularly affected due to the specialized knowledge required of the technical and support employees for generation operations. We could make acquisitions or investments in new business initiatives and new markets, which may not be successful or achieve the intended financial results. We could continue to pursue growth in our existing businesses and markets and further diversification across the competitive energy value chain. This could include opportunistic carbon-free energy acquisitions, creating new value from our existing fleet through repowering, co-location and the production of hydrogen, growing sustainability products and services for our customers, and investment opportunities in other emerging technologies and innovation. Such initiatives could involve significant risks and uncertainties, including distraction of management from current operations, inadequate return on capital, and unidentified issues not discovered during diligence performed prior to launching an initiative or entering a market. Additionally, it is possible that FERC, state public utility commissions or others could impose certain other restrictions on such transactions. All these factors could result in higher costs or lower revenues than expected, resulting in lower than planned returns on investment. Risks Related to Our Separation from Exelon We may not achieve some or all the expected benefits of the separation, and the separation may materially adversely affect our business. We may not be able to achieve the full strategic and financial benefits expected to result from the separation, or such benefits may be delayed or not occur at all. If we fail to achieve some or all the benefits expected to result from the separation, or if such benefits are delayed, it could have a material adverse effect on our competitive position, business, financial condition, results of operations and cash flows. The terms in our agreements with Exelon could be less beneficial than the terms we may have otherwise received from unaffiliated third parties. The agreements entered with Exelon in connection with the separation, including the separation agreement, a tax matters agreement, an employee matters agreement, and a transition services agreement, were prepared in the context of the separation while we were still a wholly owned subsidiary of Exelon. Accordingly, during the period in which the terms of those agreements were prepared, we did not have an independent Board of Directors or a management team that was independent of Exelon. As a result, the terms of those agreements may not reflect terms that would have resulted from negotiations between unaffiliated third parties. Exelon may fail to perform under various transaction agreements that were executed as part of the separation, which could cause us to incur expenses or losses we would not otherwise incur. In connection with the separation and prior to the distribution, we and Exelon entered into the separation agreement and entered into various other agreements, including a tax matters agreement, an employee matters agreement, and a transition services agreement. The separation agreement, the tax matters agreement and the employee matters agreement determined the allocation of assets and liabilities between the companies following the separation for those respective areas and include any necessary indemnifications related to liabilities and obligations. We will rely on Exelon to satisfy its performance and payment obligations under these agreements. If Exelon is unable or unwilling to satisfy its obligations under these agreements, including its indemnification obligations, we could incur operational difficulties and/or losses. In connection with the separation into two public companies, we and Exelon indemnified each other for certain liabilities. If we are required to pay under these indemnities to Exelon, our financial results could be negatively impacted. The Exelon indemnities may not be sufficient to hold us harmless from the full amount of liabilities for which Exelon will be allocated responsibility, and Exelon may not be able to satisfy its indemnification obligations in the future. Pursuant to the separation agreement and certain other agreements between Exelon and us, each party will agree to indemnify the other for certain liabilities, in each case for uncapped amounts. Indemnities that we may be required to provide Exelon are not subject to any cap, may be significant and could negatively impact our business. Third parties could also seek to hold us responsible for any of the liabilities that Exelon has agreed to retain. Any amounts we are required to pay pursuant to these indemnification obligations and other liabilities could require us to divert cash that would otherwise have been used in furtherance of our operating business. Further, the indemnities from Exelon for our benefit may not be sufficient to protect us against the full amount of such liabilities, and Exelon may not be able to fully satisfy its indemnification obligations. Moreover, even if we ultimately succeed in recovering from Exelon any amounts for which we are held liable, we may be temporarily required to bear these losses ourselves. Each of these risks could negatively affect our business, results of operations and financial condition. We may fail to have necessary systems and services in place when certain of the transaction agreements expire. If we do not have in place our own systems and services, or if we do not have agreements with other providers of these services once certain separation transaction agreements expire, we may not be able to operate our business effectively, and our profitability may decline. We are in the process of creating our own, or engaging third parties to provide, systems and services to replace many of the systems and services that Exelon currently provides to us. We may incur temporary interruptions in business operations if we cannot transition effectively from Exelons existing operating systems, databases and programming languages that support these functions to our own systems. Our failure to implement the new systems and transition our data successfully and cost-effectively could disrupt our business operations and have a material adverse effect on our profitability. In addition, our costs for the operation of these systems may be higher than the amounts reflected in our historical financial statements. We may not be able to engage in desirable strategic transactions or capital-raising following the separation. Under current U.S. federal income tax law, a spin-off that otherwise qualifies for tax-free treatment can be rendered taxable to the parent corporation and its shareholders as a result of certain post-spin-off transactions, including certain acquisitions of shares or assets of the spun-off corporation. To preserve the tax-free treatment of the distribution, and in addition to potential tax indemnity obligations, we agreed to certain limitations or prohibitions in the tax matters agreement that may prohibit us, for the two-year period following the distribution and except in specific circumstances, from, among other things: entering into any transaction pursuant to which all or a portion of the shares of our stock, or substantially all of our assets, would be acquired, whether by merger or otherwise; issuing equity securities beyond certain thresholds; repurchasing shares of our stock other than in certain open-market transactions. The tax matters agreement prohibits us from taking or failing to take any other action that would prevent the distribution and certain related transactions from qualifying as a transaction that is generally tax-free for U.S. federal income tax purposes under Sections 355 and 368(a)(1)(D) of the IRC. These restrictions may limit our ability to pursue certain equity issuances, strategic transactions, repurchases or other transactions that we may believe to be in the best interests of our shareholders or that might increase the value of our business.

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##TABLE_START

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ITEM 1. BUSINESS ##TABLE_START ##TABLE_ENDDUKE ENERGY ##TABLE_START ##TABLE_ENDGeneral Duke Energy was incorporated on May 3, 2005, and is an energy company headquartered in Charlotte, North Carolina, subject to regulation by the FERC and other regulatory agencies listed below. Duke Energy operates in the U.S. primarily through its direct and indirect subsidiaries. Certain Duke Energy subsidiaries are also Subsidiary Registrants, including Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida, Duke Energy Ohio, Duke Energy Indiana and Piedmont. When discussing Duke Energys consolidated financial information, it necessarily includes the results of its separate Subsidiary Registrants, which along with Duke Energy, are collectively referred to as the Duke Energy Registrants. The Duke Energy Registrants electronically file reports with the SEC, including Annual Reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and amendments to such reports. The SEC maintains an internet site that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC at sec.gov. Additionally, information about the Duke Energy Registrants, including reports filed with the SEC, is available through Duke Energys website at duke-energy.com. Such reports are accessible at no charge and are made available as soon as reasonably practicable after such material is filed with or furnished to the SEC. Business Segments Duke Energy's segment structure includes two reportable business segments: Electric Utilities and Infrastructure (EUI) and Gas Utilities and Infrastructure (GUI). The remainder of Duke Energys operations is presented as Other. Commercial Renewables is reported as discontinued operations and is no longer a reportable segment beginning in the fourth quarter of 2022. See Note 2 for further details. Duke Energy's chief operating decision-maker routinely reviews financial information about each of these business segments in deciding how to allocate resources and evaluate the performance of the business. For additional information on each of these business segments, including financial and geographic information, see Note 3 to the Consolidated Financial Statements, Business Segments. The following sections describe the business and operations of each of Duke Energys business segments, as well as Other. ELECTRIC UTILITIES AND INFRASTRUCTURE EUI conducts operations primarily through the regulated public utilities of Duke Energy Carolinas, Duke Energy Progress, Duke Energy Florida, Duke Energy Indiana and Duke Energy Ohio. EUI provides retail electric service through the generation, transmission, distribution and sale of electricity to approximately 8.2 million customers within the Southeast and Midwest regions of the U.S. The service territory is approximately 92,000 square miles across six states with a total estimated population of 26 million. The operations include electricity sold wholesale to municipalities, electric cooperative utilities and other load-serving entities. During 2021, Duke Energy executed an agreement providing for an investment by an affiliate of GIC in Duke Energy Indiana in exchange for a 19.9% minority interest issued by Duke Energy Indiana Holdco, LLC, the holding company for Duke Energy Indiana. The transaction was completed following two closings. Additionally, in November 2022, Duke Energy committed to a plan to sell the Commercial Renewables business segment, excluding the offshore wind contract for Carolina Long Bay, which was moved to EUI. See Note 2 to the Consolidated Financial Statements, Dispositions," for additional information. EUI is also a joint owner in certain electric transmission projects. EUI has a 50% ownership interest in DATC, a partnership with American Transmission Company, formed to design, build and operate transmission infrastructure. DATC owns 72% of the transmission service rights to Path 15, an 84-mile transmission line in central California. EUI also has a 50% ownership interest in Pioneer, which builds, owns and operates electric transmission facilities in North America. The following map shows the service territory for EUI as of December 31, 2022. ##TABLE_START BUSINESS ##TABLE_ENDThe electric operations and investments in projects are subject to the rules and regulations of the FERC, the NRC, the NCUC, the PSCSC, the FPSC, the IURC, the PUCO and the KPSC. The following table represents the distribution of GWh billed sales by customer class for the year ended December 31, 2022. ##TABLE_START Duke Duke Duke Duke Duke Energy Energy Energy Energy Energy Carolinas Progress Florida Ohio Indiana Residential 33 % 26 % 47 % 38 % 30 % General service 33 % 22 % 34 % 38 % 27 % Industrial 23 % 16 % 8 % 22 % 28 % Total retail sales 89 % 64 % 89 % 98 % 85 %

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Wholesale and other sales 11 % 36 % 11 % 2 % 15 % Total sales 100 % 100 % 100 % 100 % 100 % ##TABLE_ENDThe number of residential and general service customers within the EUI service territory is expected to increase over time. Sales growth is expected within the service territory but continues to be impacted by adoption of energy efficiencies and self-generation. Migration into EUIs service territories and continued remote work contributed to higher residential sales volumes in 2022 while higher data center usage contributed to growth in commercial sales volumes. This was partially offset by lower industrial sales volumes impacted by certain automotive customers experiencing supply chain constraints along with reduced volumes in the steel sector. The impact on customer's usage from these factors and other potential economic dynamics continues to be monitored. Over the longer time frame, it is still expected that the continued adoption of more efficient housing and appliances will have a negative impact on average usage per residential customer over time. Seasonality and the Impact of Weather Revenues and costs are influenced by seasonal weather patterns. Peak sales of electricity occur during the summer and winter months, which results in higher revenue and cash flows during these periods. By contrast, lower sales of electricity occur during the spring and fall, allowing for scheduled plant maintenance. Residential and general service customers are more impacted by weather than industrial customers. Estimated weather impacts are based on actual current period weather compared to normal weather conditions. Normal weather conditions are defined as the long-term average of actual historical weather conditions. The estimated impact of weather on earnings is based on the temperature variances from a normal condition and customers historic usage patterns. The methodology used to estimate the impact of weather does not consider all variables that may impact customer response to weather conditions such as humidity in the summer or wind chill in the winter. The precision of this estimate may also be impacted by applying long-term weather trends to shorter-term periods. ##TABLE_START BUSINESS ##TABLE_ENDHeating degree days measure the variation in weather based on the extent the average daily temperature falls below a base temperature. Cooling degree days measure the variation in weather based on the extent the average daily temperature rises above the base temperature. Each degree of temperature below the base temperature counts as one heating degree day and each degree of temperature above the base temperature counts as one cooling degree day. Competition Retail EUIs businesses operate as the sole supplier of electricity within their service territories, with the exception of Ohio, which has a competitive electricity supply market for generation service. EUI owns and operates facilities necessary to generate, transmit, distribute and sell electricity. Services are priced by state commission-approved rates designed to include the costs of providing these services and a reasonable return on invested capital. This regulatory policy is intended to provide safe and reliable electricity at fair prices. In Ohio, EUI conducts competitive auctions for electricity supply. The cost of energy purchased through these auctions is recovered from retail customers. EUI earns retail margin in Ohio on the transmission and distribution of electricity, but not on the cost of the underlying energy. Competition in the regulated electric distribution business is primarily from the development and deployment of alternative energy sources including on-site generation from industrial customers and distributed generation, such as private solar, at residential, general service and/or industrial customer sites. Wholesale Duke Energy competes with other utilities and merchant generators for bulk power sales, sales to municipalities and cooperatives and wholesale transactions under primarily cost-based contracts approved by FERC. The principal factors in competing for these sales are availability of capacity and power, reliability of service and price. Prices are influenced primarily by market conditions and fuel costs. Increased competition in the wholesale electric utility industry and the availability of transmission access could affect EUIs load forecasts, plans for power supply and wholesale energy sales and related revenues. Wholesale energy sales will be impacted by the extent to which additional generation is available to sell to the wholesale market and the ability of EUI to attract new customers and to retain existing customers. Energy Capacity and Resources EUI owns approximately 49,870 MW of generation capacity. For additional information on owned generation facilities, see Item 2, Properties. Energy and capacity are also supplied through contracts with other generators and purchased on the open market. Factors that could cause EUI to purchase power for its customers may include, but are not limited to, generating plant outages, extreme weather conditions, generation reliability, demand growth and price. EUI has interconnections and arrangements with its neighboring utilities to facilitate planning, emergency assistance, sale and purchase of capacity and energy and reliability of power supply. EUIs generation portfolio is a balanced mix of energy resources having different operating characteristics and fuel sources designed to provide energy at the lowest possible cost to meet its obligation to serve retail customers. All options, including owned generation resources and purchased power opportunities, are continually evaluated on a real-time basis to select and dispatch the lowest-cost resources available to meet system load requirements. Sources of Electricity EUI relies principally on natural gas, nuclear fuel and coal for its generation of electricity. The following table lists sources of electricity and fuel costs for the three years ended December 31, 2022. ##TABLE_START Cost of Delivered Fuel per Net Generation by Source Kilowatt-hour Generated (Cents) 2022 2021 2020 2022 2021 2020 Natural gas and fuel oil (a) 34.2 % 31.8 % 31.3 % 6.35 3.89 2.55 Nuclear (a) 26.6 % 29.8 % 29.6 % 0.58 0.58 0.58 Coal (a) 13.5 % 18.2 % 18.1 % 3.43 2.84 2.99 All fuels (cost based on weighted average) (a) 74.3 % 79.8 % 79.0 % 3.75 2.42 1.91 Hydroelectric and solar (b) 1.5 % 1.5 % 1.9 % Total generation 75.8 % 81.3 % 80.9 % Purchased power and net interchange 24.2 % 18.7 % 19.1 % Total sources of energy 100.0 % 100.0 % 100.0 % ##TABLE_END(a) Statistics related to all fuels reflect EUI's public utility ownership interest in jointly owned generation facilities. (b) Generating figures are net of output required to replenish pumped-storage facilities during off-peak periods. Natural Gas and Fuel Oil Natural gas and fuel oil supply, transportation and storage for EUIs generation fleet is purchased under standard industry agreements from various suppliers, including Piedmont. Natural gas supply agreements typically provide for a percentage of forecasted burns being procured over time, with varied expiration dates. Electric Utilities and Infrastructure believes it has access to an adequate supply of natural gas and fuel oil for the reasonably foreseeable future. ##TABLE_START BUSINESS ##TABLE_ENDEUI has certain dual-fuel generating facilities that can operate utilizing both natural gas and fuel oil. The cost of EUIs natural gas and fuel oil is fixed price or determined by published market prices as reported in certain industry publications, plus any transportation and freight costs. Duke Energy Carolinas, Duke Energy Progress, Duke Energy Florida and Duke Energy Indiana use derivative instruments to manage a portion of their exposure to price fluctuations for natural gas. Duke Energy Florida has temporarily agreed to not hedge natural gas prices, but retains an ability to propose hedging again in annual fuel docket filings. EUI has firm interstate and intrastate natural gas transportation agreements and storage agreements in place to support generation needed for load requirements. EUI may purchase additional shorter-term natural gas transportation and utilize natural gas interruptible transportation agreements to support generation needed for load requirements. The EUI natural gas plants are served by various supply zones and multiple pipelines. Nuclear The industrial processes for producing nuclear generating fuel generally involve the mining and milling of uranium ore to produce uranium concentrates and services to convert, enrich and fabricate fuel assemblies. EUI has contracted for uranium materials and services to fuel its nuclear reactors. Uranium concentrates, conversion services and enrichment services are primarily met through a diversified portfolio of long-term supply contracts. The contracts are diversified by supplier, country of origin and pricing. EUI staggers its contracting so that its portfolio of long-term contracts covers the majority of its fuel requirements in the near term and decreasing portions of its fuel requirements over time thereafter. Near-term requirements not met by long-term supply contracts have been and are expected to be fulfilled with spot market purchases. Due to the technical complexities of changing suppliers of fuel fabrication services, EUI generally source these services to a single domestic supplier on a plant-by-plant basis using multiyear contracts. EUI has entered into fuel contracts that cover 100% of its uranium concentrates through at least 2024, 100% of its conversion services through at least 2026, 100% of its enrichment services through at least 2026, and 100% of its fabrication services requirements for these plants through at least 2027. For future requirements not already covered under long-term contracts, EUI believes it will be able to renew contracts as they expire or enter into similar contractual arrangements with other suppliers of nuclear fuel materials and services. Coal EUI meets its coal demand through a portfolio of long-term purchase contracts and short-term spot market purchase agreements. Large amounts of coal are purchased under long-term contracts with mining operators who mine both underground and at the surface. EUI uses spot market purchases to meet coal requirements not met by long-term contracts. Expiration dates for its long-term contracts, which may have various price adjustment provisions and market reopeners, range from 2023 to 2027 for Duke Energy Carolinas and Duke Energy Indiana, 2023 to 2024 for Duke Energy Progress and 2023 to 2025 for Duke

Energy Florida and Duke Energy Ohio. EUI expects to renew these contracts or enter into similar contracts with other suppliers as existing contracts expire, though prices will fluctuate over time as coal markets change. EUI has an adequate supply of coal under contract to meet its risk management guidelines regarding projected future consumption. As a result of volatility in natural gas prices and the associated impacts on coal-fired dispatch within the generation fleet, coal inventories will continue to fluctuate. EUI continues to actively manage its portfolio and has worked with suppliers to obtain increased flexibility in its coal contracts. Coal purchased for the Carolinas is primarily produced from mines in Central Appalachia, Northern Appalachia and the Illinois Basin. Coal purchased for Florida is primarily produced from mines in the Illinois Basin. Coal purchased for Kentucky is produced from mines along the Ohio River in Illinois, Ohio, West Virginia and Pennsylvania. Coal purchased for Indiana is primarily produced in Indiana and Illinois. There are adequate domestic coal reserves to serve EUI's coal generation needs through end of life. The current average sulfur content of coal purchased by Electric Utilities and Infrastructure is between 0.5% and 3.5% for Duke Energy Carolinas and Duke Energy Progress, and between 0.5% and 4% for Duke Energy Florida, Duke Energy Ohio and Duke Energy Indiana. EUI's environmental controls, in combination with the use of sulfur dioxide (SO 2) emission allowances, enable EUI to satisfy current SO 2 emission limitations for its existing facilities. Purchased Power EUI purchases a portion of its capacity and system requirements through purchase obligations, leases and purchase capacity contracts. EUI believes it can obtain adequate purchased power capacity to meet future system load needs. However, during periods of high demand, the price and availability of purchased power may be significantly affected. The following table summarizes purchased power for the previous three years: ##TABLE_START 2022 2021 2020 Purchase obligations and leases (in millions of MWh) (a) 41.2 36.0 32.7 Purchase capacity under contract (in MW) (b) 4,028 4,259 4,716 ##TABLE_END(a) Represents approximately 16% of total system requirements for 2022, 14% for 2021 and 13% for 2020. (b) For 2022, 2021 and 2020, these agreements include approximately 412 MW of firm capacity under contract by Duke Energy Florida with QFs. Inventory EUI must maintain an adequate stock of fuel and materials and supplies in order to ensure continuous operation of generating facilities and reliable delivery to customers. As of December 31, 2022, the inventory balance for EUI was approximately $3.4 billion. For additional information on inventory, see Note 1 to the Consolidated Financial Statements, Summary of Significant Accounting Policies. ##TABLE_START BUSINESS ##TABLE_ENDAsh Basin Management During 2015, EPA issued regulations related to the management of CCR from power plants. These regulations classify CCR as nonhazardous waste under the Resource Conservation and Recovery Act (RCRA) and apply to electric generating sites with new and existing landfills and new and existing surface impoundments and establish requirements regarding landfill design, structural integrity design and assessment criteria for surface impoundments, groundwater monitoring, protection and remedial procedures and other operational and reporting procedures for the disposal and management of CCR. In addition to the federal regulations, CCR landfills and surface impoundments (ash basins or impoundments) will continue to be regulated by existing state laws, regulations and permits, such as the North Carolina Coal Ash Management Act of 2014 (Coal Ash Act). EUI has and will periodically submit to applicable authorities required site-specific coal ash impoundment remediation or closure plans. Closure plans must be approved and all associated permits issued before any work can begin. Closure activities have begun in all of Duke Energy's jurisdictions. Excavation began in 2015 at the four sites specified as high priority by the Coal Ash Act and at the W.S. Lee Steam Station site in South Carolina in connection with other legal requirements. Excavation at these sites involves movement of CCR materials to appropriate engineered off-site or on-site lined landfills or for reuse in an approved beneficial application. Duke Energy has completed excavation of coal ash at the four high-priority North Carolina sites. At other sites where CCR management is required, planning and closure methods have been studied and factored into the estimated retirement and management costs, and closure activities have commenced. The EPA CCR rule and the Coal Ash Act leave the decision on cost recovery determinations related to closure of coal ash surface impoundments to the normal ratemaking processes before utility regulatory commissions. Duke Energy's electric utilities have included compliance costs associated with federal and state requirements in their respective rate proceedings. During 2017, Duke Energy Carolinas' and Duke Energy Progress wholesale contracts were amended to include the recovery of expenditures related to AROs for the closure of coal ash basins. The amended contracts have retail disallowance parity or provisions limiting challenges to CCR cost recovery actions at FERC. FERC approved the amended wholesale rate schedules in 2017. For additional information on the ash basins and recovery, see Item 7, "Other Matters" and Notes 4, 5 and 10 to the Consolidated Financial Statements, "Regulatory Matters," "Commitments and Contingencies" and "Asset Retirement Obligations," respectively. Nuclear Matters Duke Energy owns, wholly or partially, 11 operating nuclear reactors located at six operating stations. The Crystal River Unit 3 permanently ceased operation in February 2013. Nuclear insurance includes: nuclear liability coverage; property damage coverage; nuclear accident decontamination and premature decommissioning coverage; and accidental outage coverage for losses in the event of a major accidental outage. Joint owners reimburse Duke Energy for certain expenses associated with nuclear insurance in accordance with joint owner agreements. The Price-Anderson Act requires plant owners to provide for public nuclear liability claims resulting from nuclear incidents to the maximum total financial protection liability, which is approximately $13.7 billion. For additional information on nuclear insurance, see Note 5 to the Consolidated Financial Statements, Commitments and Contingencies. Duke Energy has a significant future financial commitment to dispose of spent nuclear fuel and decommission and decontaminate each plant safely. The NCUC, PSCSC and FPSC require Duke Energy to update their cost estimates for decommissioning their nuclear plants every five years. The following table summarizes the fair value of NDTF investments and the most recent site-specific nuclear decommissioning cost studies. Decommissioning costs are stated in 2018 or 2019 dollars, depending on the year of the cost study, and include costs to decommission plant components not subject to radioactive contamination. ##TABLE_START NDTF (a) Decommissioning (in millions) December 31, 2022 December 31, 2021 Costs (a) Year of Cost Study Duke Energy $ 8,637 $ 10,401 $ 9,105 2018 or 2019 Duke Energy Carolinas (b)(c) 4,783 5,759 4,365 2018 Duke Energy Progress (d) 3,430 4,089 4,181 2019 Duke Energy Florida (e) 424 553 559 N/A ##TABLE_END(a) Amounts for Progress Energy equal the sum of Duke Energy Progress and Duke Energy Florida. (b) Decommissioning cost for Duke Energy Carolinas reflects its ownership interest in jointly owned reactors. Other joint owners are responsible for decommissioning costs related to their interest in the reactors. (c) Duke Energy Carolinas' site-specific nuclear decommissioning cost study completed in 2018 was filed with the NCUC and PSCSC in 2019. A new funding study was also completed and filed with the NCUC and PSCSC in 2019. (d) Duke Energy Progress' site-specific nuclear decommissioning cost study completed in 2019 was filed with the NCUC and PSCSC in March 2020. Duke Energy Progress also completed a funding study, which was filed with the NCUC and PSCSC in July 2020. In October 2021, Duke Energy Progress filed the 2019 nuclear decommissioning cost study with the FERC, as well as a revised date schedule for decommissioning expense to be collected from wholesale customers. The FERC accepted the filing, as filed on December 9, 2021. (e) During 2019, Duke Energy Florida reached an agreement to transfer decommissioning work for Crystal River Unit 3 to a third party and decommissioning costs are based on the agreement with this third party rather than a cost study. Regulatory approval was received from the NRC and the FPSC in April 2020 and August 2020, respectively. See Note 4 to the Consolidated Financial Statements, "Regulatory Matters, for more information. The NCUC, PSCSC, FPSC and FERC have allowed EUI to recover estimated decommissioning costs through retail and wholesale rates over the expected remaining service periods of their nuclear stations. EUI believes the decommissioning costs being recovered through rates, when coupled with the existing fund balances and expected fund earnings, will be sufficient to provide for the cost of future decommissioning. For additional information, see Note 10 to the Consolidated Financial Statements, Asset Retirement Obligations. ##TABLE_START BUSINESS ##TABLE_ENDThe Nuclear Waste Policy Act of 1982 (as amended) provides the framework for development by the federal government of interim storage and permanent disposal facilities for high-level radioactive waste materials. The government has not yet developed a storage facility or disposal capacity, so EUI will continue to store spent fuel on its reactor sites. Under federal law, the DOE is responsible for the selection and construction of a facility for the permanent disposal of spent nuclear fuel and high-level radioactive waste. The DOE terminated the project to license and develop a geologic repository at Yucca Mountain, Nevada in 2010, and is currently taking no action to fulfill its responsibilities to dispose of spent fuel. Until the DOE begins to accept the spent nuclear fuel, Duke Energy Carolinas, Duke Energy Progress and

Duke Energy Florida will continue to safely manage their spent nuclear fuel. Under current regulatory guidelines, Harris has sufficient storage capacity in its spent fuel pools through the expiration of its renewed operating license. With certain modifications and approvals by the NRC to expand the on-site dry cask storage facilities, spent nuclear fuel dry storage facilities will be sufficient to provide storage space of spent fuel through the expiration of the operating licenses, including any license renewals, for Brunswick, Catawba, McGuire, Oconee and Robinson. Crystal River Unit 3 ceased operation in 2013 and was placed in a SAFSTOR condition in January 2018. As of January 2018, all spent fuel at Crystal River Unit 3 has been transferred from the spent fuel pool to dry storage at an on-site independent spent fuel storage installation. During 2020, the NRC and the FPSC approved an agreement to transfer ownership of spent fuel for Crystal River Unit 3 to a third party. See Note 4 to the Consolidated Financial Statements, "Regulatory Matters, for more information. The nuclear power industry faces uncertainties with respect to the cost and long-term availability of disposal sites for spent nuclear fuel and other radioactive waste, compliance with changing regulatory requirements, capital outlays for modifications and new plant construction. EUI is subject to the jurisdiction of the NRC for the design, construction and operation of its nuclear generating facilities. The following table includes the current year of expiration of nuclear operating licenses for nuclear stations in operation. In June 2021, Duke Energy Carolinas filed a subsequent license renewal application for the Oconee Nuclear Station (ONS) with the U.S. Nuclear Regulatory Commission to renew ONS's operating license for an additional 20 years. Duke Energy has announced its intention to seek 20-year operating license renewals for each of the reactors it operates in Duke Energy Carolinas and Duke Energy Progress. See Note 4 to the Consolidated Financial Statements, "Regulatory Matters, for additional information. ##TABLE_START Unit Year of Expiration Duke Energy Carolinas Catawba Units 1 and 2 2043 McGuire Unit 1 2041 McGuire Unit 2 2043 Oconee Units 1 and 2 2033 Oconee Unit 3 2034 Duke Energy Progress Brunswick Unit 1 2036 Brunswick Unit 2 2034 Harris 2046 Robinson 2030 ##TABLE_ENDThe NRC has acknowledged permanent cessation of operation and permanent removal of fuel from the reactor vessel at Crystal River Unit 3. Therefore, the license no longer authorizes operation of the reactor. For additional information on nuclear decommissioning activity, see Notes 4 and 10 to the Consolidated Financial Statements, "Regulatory Matters" and "Asset Retirement Obligations," respectively. Regulation State The state electric utility commissions approve rates for Duke Energy's retail electric service within their respective states. The state electric utility commissions, to varying degrees, have authority over the construction and operation of EUIs generating facilities. CPCNs issued by the state electric utility commissions, as applicable, authorize EUI to construct and operate its electric facilities and to sell electricity to retail and wholesale customers. Prior approval from the relevant state electric utility commission is required for the entities within EUI to issue securities. The underlying concept of utility ratemaking is to set rates at a level that allows the utility to collect revenues equal to its cost of providing service plus earn a reasonable rate of return on its invested capital, including equity. In addition to rates approved in base rate cases, each of the state electric utility commissions allow recovery of certain costs through various cost recovery clauses to the extent the respective commission determines in periodic hearings that such costs, including any past over or under-recovered costs, are prudent. Fuel, fuel-related costs and certain purchased power costs are eligible for recovery by EUI. EUI uses coal, hydroelectric, natural gas, oil, renewable generation and nuclear fuel to generate electricity, thereby maintaining a diverse fuel mix that helps mitigate the impact of cost increases in any one fuel. Due to the associated regulatory treatment and the method allowed for recovery, changes in fuel costs from year to year have no material impact on operating results of EUI, unless a commission finds a portion of such costs to have been imprudent. However, delays between the expenditure for fuel costs and recovery from customers can adversely impact the timing of cash flows of EUI. ##TABLE_START BUSINESS ##TABLE_ENDThe table below reflects significant electric rate case applications approved and effective in the past three years and applications currently pending approval. ##TABLE_START Regulatory Body Annual Increase (Decrease) (in millions) Return on Equity Equity Component of Capital Structure Effective Date Approved Rate Cases: Duke Energy Progress 2022 South Carolina Rate Case PSCSC $ 52 9.6 % 52.43 % 4/1/2023 Duke Energy Ohio 2021 Ohio Electric Rate Case PUCO 23 9.5 % 50.5 % 1/3/2023 Duke Energy Progress 2019 North Carolina Rate Case NCUC 178 9.6 % 52 % 6/1/2021 Duke Energy Carolinas 2019 North Carolina Rate Case NCUC 33 9.6 % 52 % 6/1/2021 Duke Energy Indiana 2019 Indiana Rate Case (a) IURC 146 9.7 % 54 % 7/30/2020 Duke Energy Kentucky 2019 Kentucky Electric Rate Case KPSC 24 9.25 % 48.23 % 5/1/2020 Pending Rate Cases: Duke Energy Carolinas 2023 North Carolina Rate Case (b) NCUC $ 823 10.4 % 53 % 1/1/2024 Duke Energy Kentucky 2022 Kentucky Electric Rate Case KPSC 75 10.35 % 52.5 % 7/15/2023 Duke Energy Progress 2022 North Carolina Rate Case (c) NCUC 615 10.4 % 53 % 10/1/2023 ##TABLE_END(a) Step 1 rates are approximately 75% of the total and became effective July 30, 2020. Step 2 rates are approximately 25% of the total rate case increase. They were approved on July 28, 2021, and implemented in August 2021. (b) Year 1 rates are approximately 61% of the total. Year 2 rates are approximately 21% of the total rate case increase. Year 3 rates are approximately 18% of the total rate increase. (c) Year 1 rates are approximately 53% of the total. Year 2 rates are approximately 25% of the total rate case increase. Year 3 rates are approximately 22% of the total rate increase. Implementation of interim rates is planned for June 1, 2023. Additionally, in January 2021, Duke Energy Florida filed a settlement agreement with the FPSC that will allow annual increases to its base rates, an agreed upon return on equity (ROE) and includes a base rate stay-out provision through 2024, among other provisions. The FPSC approved the 2021 Settlement on May 4, 2021, issuing an order on June 4, 2021. Revised customer rates became effective January 1, 2022, with subsequent base rate increases effective January 1, 2023, and January 1, 2024. For more information on rate matters and other regulatory proceedings, see Note 4 to the

Consolidated Financial Statements, Regulatory Matters. Federal The FERC approves EUIs cost-based rates for electric sales to certain power and transmission wholesale customers. Regulations of FERC and the state electric utility commissions govern access to regulated electric and other data by nonregulated entities and services provided between regulated and nonregulated energy affiliates. These regulations affect the activities of nonregulated affiliates with EUI. RTOs PJM and MISO are the ISOs and FERC-approved RTOs for the regions in which Duke Energy Ohio and Duke Energy Indiana operate. PJM and MISO operate energy, capacity and other markets, and control the day-to-day operations of bulk power systems through central dispatch. Duke Energy Ohio is a member of PJM and Duke Energy Indiana is a member of MISO. Transmission owners in these RTOs have turned over control of their transmission facilities and their transmission systems are currently under the dispatch control of the RTOs. Transmission service is provided on a regionwide, open-access basis using the transmission facilities of the RTO members at rates based on the costs of transmission service. Environmental EUI is subject to the jurisdiction of the EPA and state and local environmental agencies. For a discussion of environmental regulation, see Environmental Matters in this section. See the Other Matters section of Item 7 Management's Discussion and Analysis for a discussion about potential Global Climate Change legislation and other EPA regulations under development and the potential impacts such legislation and regulation could have on Duke Energys operations. GAS UTILITIES AND INFRASTRUCTURE GUI conducts natural gas operations primarily through the regulated public utilities of Piedmont, Duke Energy Ohio and Duke Energy Kentucky. The natural gas operations are subject to the rules and regulations of the NCUC, PSCSC, PUCO, KPSC, TPUC, PHMSA and the FERC. GUI serves residential, commercial, industrial and power generation natural gas customers, including customers served by municipalities who are wholesale customers. GUI has over 1.6 million total customers, including 1.1 million customers located in North Carolina, South Carolina and Tennessee, and an additional 550,000 customers located within southwestern Ohio and northern Kentucky. In the Carolinas, Ohio and Kentucky, the service areas are comprised of numerous cities, towns and communities. In Tennessee, the service area is the metropolitan area of Nashville. The following map shows the service territory and investments in operating pipelines for GUI as of December 31, 2022. ##TABLE_START BUSINESS ##TABLE_ENDThe number of residential, commercial and industrial customers within the GUI service territory is expected to increase over time. Average usage per residential customer is expected to remain flat or decline for the foreseeable future; however, decoupled rates in North Carolina and various rate design mechanisms in other jurisdictions partially mitigate the impact of the declining usage per customer on overall profitability. GUI also has investments in various pipeline transmission projects, renewable natural gas projects and natural gas storage facilities. Natural Gas for Retail Distribution GUI is responsible for the distribution of natural gas to retail customers in its North Carolina, South Carolina, Tennessee, Ohio and Kentucky service territories. GUIs natural gas procurement strategy is to contract primarily with major and independent producers and marketers for natural gas supply. It also purchases a diverse portfolio of transportation and storage service from interstate pipelines. This strategy allows GUI to assure reliable natural gas supply and transportation for its firm customers during peak winter conditions. When firm pipeline services or contracted natural gas supplies are temporarily not needed due to market demand fluctuations, GUI may release these services and supplies in the secondary market under FERC-approved capacity release provisions or make wholesale secondary market sales. In 2022, firm supply purchase commitment agreements provided 100% of the natural gas supply for both Piedmont and Duke Energy Ohio. Approximately 90% of forecasted demand was under contract prior to the winter heating season, with firm daily spot purchases making up the balance. ##TABLE_START BUSINESS ##TABLE_ENDImpact of Weather GUI revenues are generally protected from the impact of weather fluctuations due to the regulatory mechanisms that are available in most service territories. In North Carolina, margin decoupling provides protection from both weather and other usage variations like conservation for residential and small and medium general service customers. Margin decoupling provides a set margin per customer independent of actual usage. In South Carolina, Tennessee and Kentucky, weather normalization adjusts revenues either up or down depending on how much warmer or colder than normal a given month has been. Weather normalization adjustments occur from November through March in South Carolina, from October through April in Tennessee and from November through April in Kentucky. Duke Energy Ohio collects most of its non-fuel revenue through a fixed monthly charge that is not impacted by usage fluctuations that result from weather changes or conservation. Competition GUIs businesses operate as the sole provider of natural gas service within their retail service territories. GUI owns and operates facilities necessary to transport and distribute natural gas. GUI earns retail margin on the transmission and distribution of natural gas and not on the cost of the underlying commodity. Services are priced by state commission-approved rates designed to include the costs of providing these services and a reasonable return on invested capital. This regulatory policy is intended to provide safe and reliable natural gas service at fair prices. In residential, commercial and industrial customer markets, natural gas distribution operations compete with other companies that supply energy, primarily electric companies, propane and fuel oil dealers, renewable energy providers and coal companies in relation to sources of energy for electric power plants, as well as nuclear energy. A significant competitive factor is price. GUI's primary product competition is with electricity for heating, water heating and cooking. Increases in the price of natural gas or decreases in the price of other energy sources could negatively impact competitive position by decreasing the price benefits of natural gas to the consumer. In the case of industrial customers, such as manufacturing plants, adverse economic or market conditions, including higher natural gas costs, could cause these customers to suspend business operations or to use alternative sources of energy in favor of energy sources with lower per-unit costs. Higher natural gas costs or decreases in the price of other energy sources may allow competition from alternative energy sources for applications that have traditionally used natural gas, encouraging some customers to move away from natural gas-fired equipment to equipment fueled by other energy sources. Competition between natural gas and other forms of energy is also based on efficiency, performance, reliability, safety and other non-price factors. Technological improvements in other energy sources and events that impair the public perception of the non-price attributes of natural gas could erode our competitive advantage. These factors in turn could decrease the demand for natural gas, impair our ability to attract new customers and cause existing customers to switch to other forms of energy or to bypass our systems in favor of alternative competitive sources. This could result in slow or no customer growth and could cause customers to reduce or cease using our product, thereby reducing our ability to make capital expenditures and otherwise grow our business, adversely affecting our earnings. Natural Gas Investments Duke Energy, through its GUI segment, has a 7.5% equity ownership interest in Sabal Trail. Sabal Trail is a joint venture that owns the Sabal Trail Natural Gas Pipeline (Sabal Trail pipeline) to transport natural gas to Florida, regulated by FERC. The Sabal Trail Phase I mainline was placed into service in July 2017 and traverses Alabama, Georgia and Florida. The remaining lateral line to the Duke Energy Florida's Citrus County CC was placed into service in March 2018. Phase II of Sabal Trail went into service in May 2020, adding approximately 200,000 Dth of capacity to the Sabal Trail pipeline. Duke Energy, through its GUI segment, has a 47% equity ownership interest in ACP, which planned to build the ACP pipeline, an approximately 600-mile interstate natural gas pipeline. The ACP pipeline was intended to transport diverse natural gas supplies into southeastern markets and would be regulated by FERC. Dominion Energy owns 53% of ACP and was contracted to construct and operate the ACP pipeline upon completion. On July 5, 2020, Dominion announced a sale of substantially all of its natural gas transmission and storage segment assets, which were critical to the ACP pipeline. Further, permitting delays and legal challenges had materially affected the timing and cost of the pipeline. As a result, Duke Energy determined that they would no longer invest in the construction of the ACP pipeline. Duke Energy, also through its GUI segment, has investments in various renewable natural gas joint ventures. GUI has a 21.49% equity ownership interest in Cardinal, an intrastate pipeline located in North Carolina regulated by the NCUC, a 45% equity ownership in Pine Needle, an interstate liquefied natural gas storage facility located in North Carolina and a 50% equity ownership interest in Hardy Storage, an underground interstate natural gas storage facility located in Hardy and Hampshire counties in West Virginia. Pine Needle and Hardy Storage are regulated by FERC. KO Transmission Company (KO Transmission), a wholly owned subsidiary of Duke Energy Ohio, is an interstate pipeline company engaged in the business of transporting natural gas and is subject to the rules and regulations of FERC. KO Transmission's 90-mile pipeline supplies natural gas to Duke Energy Ohio and interconnects with the Columbia Gulf Transmission pipeline and Tennessee Gas Pipeline. An approximately 70-mile portion of KO Transmission's pipeline facilities is co-owned by Columbia Gas Transmission, LLC. KO Transmission sold all of its pipeline facilities and related real property to Columbia Gas Transmission, LLC on February 1, 2023, for approximately book value. See Notes 4, 13 and 18 to the Consolidated Financial Statements, "Regulatory Matters," "Investments in Unconsolidated Affiliates" and "Variable Interest Entities," respectively, for further information on Duke Energy's and GUI's natural gas investments. Inventory GUI must maintain adequate natural gas inventory in order to provide reliable delivery to customers. As of December 31, 2022, the inventory balance for GUI was $185 million. For more information on inventory, see Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies." ##TABLE_START BUSINESS ##TABLE_ENDRegulation State The state gas utility commissions approve rates for Duke Energy's retail natural gas service within their respective states. The state gas utility commissions, to varying degrees, have authority over the construction and operation of GUIs natural gas distribution facilities. CPCNs issued by the state gas utility commissions or other government agencies, as applicable, authorize GUI to construct and operate its natural gas distribution facilities and to sell natural gas to retail and wholesale customers. Prior approval from the relevant state gas utility commission is required for GUI to issue securities. The underlying concept of utility ratemaking is to set rates at a level that allows the utility to collect revenues equal to its cost of providing service plus a reasonable rate of return on its invested capital, including equity. In addition to amounts collected from customers through approved base rates, each of the state gas utility commissions allow recovery of certain costs through various cost recovery clauses to the extent the respective commission determines in periodic hearings that such costs, including any past over- or under-recovered costs, are prudent. Natural gas costs are eligible for recovery by GUI. Due to the associated regulatory treatment and the method allowed for recovery, changes in natural gas costs from year to year have no material impact on operating results of GUI, unless a commission finds a portion of such costs to have been imprudent. However, delays between the expenditure for natural gas and recovery from customers can adversely impact the timing of cash flows of GUI. The following table summarizes certain components underlying recently approved and effective base rates or rate stabilization filings in the last three years and applications currently pending approval. ##TABLE_START Annual Increase (Decrease) (in millions) Return on Equity Equity Component of Capital Structure Effective Date Approved Rate Cases: Piedmont 2020 Tennessee Natural Gas Base Rate Case $ 16 9.8 % 50.5 % January 2021 Piedmont 2021 North Carolina Natural Gas Base Rate Case 67 9.6 % 51.6 % November 2021 Piedmont 2021 South Carolina Rate Stabilization Adjustment Filing 7 9.8 % 52.2 % November 2021 Duke Energy Kentucky 2021 Natural Gas Base Rate Case (a) 9 9.38 % 51.3 % January 2022 Piedmont 2022 South Carolina Natural Gas Base Rate Case (b) 2 9.3 % 52.2 % November 2022 Pending Rate Cases: Duke Energy Ohio 2022 Natural Gas Base Rate Case 49 10.3 % 52.3 % April 2023 ##TABLE_END(a) An ROE of 9.375% for natural gas base rates and 9.3% for natural gas riders was approved. (b)

Under the rate stabilization adjustment (RSA) mechanism, Piedmont resets rates in South Carolina based on updated costs and revenues on an annual basis. The SC RSA filing for 2022 did not reset the rates since Piedmont filed a General Rate Case in 2022. GUI has an IMR mechanism in North Carolina designed to separately track and recover certain costs associated with capital investments incurred to comply with federal pipeline safety and integrity programs. Piedmont has withdrawn from the Tennessee IMR mechanism subsequent to the authorization of the Tennessee Annual Review Mechanism effective January 2022. The following table summarizes information related to the recently approved IMR filing. ##TABLE_START Cumulative Annual Effective (in millions) Investment Revenues Date Piedmont 2022 IMR Filing North Carolina $ 213 $ 20 December 2022 ##TABLE_ENDIn Ohio, GUI has a Capital Expenditure Program Rider (CEP Rider) designed to recover costs between rate cases on PUCO approved capital expenditures. Duke Energy Ohio submits a filing each year for incremental investments to increase the revenue requirement up to the cap of approximately $7 million. The cumulative investment under the CEP Rider is $359 million with total annual revenue requirement of $70 million. For more information on rate matters and other regulatory proceedings, see Note 4 to the Consolidated Financial Statements, Regulatory Matters. Federal GUI is subject to various federal regulations, including regulations that are particular to the natural gas industry. These federal regulations include but are not limited to the following: Regulations of the FERC affect the certification and siting of new interstate natural gas pipeline projects, the purchase and sale of, the prices paid for, and the terms and conditions of service for the interstate transportation and storage of natural gas. Regulations of the PHMSA affect the design, construction, operation, maintenance, integrity, safety and security of natural gas distribution and transmission systems. Regulations of the EPA relate to the environment including proposed air emissions regulations that would expand to include emissions of methane. ##TABLE_START BUSINESS ##TABLE_ENDRegulations of the FERC and the state gas utility commissions govern access to regulated natural gas and other data by nonregulated entities and services provided between regulated and nonregulated energy affiliates. These regulations affect the activities of nonregulated affiliates with Gas Utilities and Infrastructure. Environmental GUI is subject to the jurisdiction of the EPA and state and local environmental agencies. For a discussion of environmental regulation, see Environmental Matters in this section. See Other Matters section of Item 7 Management's Discussion and Analysis for a discussion about potential Global Climate Change legislation and other EPA regulations under development and the potential impacts such legislation and regulation could have on Duke Energys operations. OTHER The remainder of Duke Energys operations is presented as Other. While it is not a business segment, Other primarily includes interest expense on holding company debt, unallocated corporate costs, amounts related to certain companywide initiatives and contributions made to the Duke Energy Foundation. Other also includes Bison and an investment in NMC. The Duke Energy Foundation is a nonprofit organization funded by Duke Energy shareholders that makes charitable contributions to selected nonprofits and government subdivisions. Bison, a wholly owned subsidiary of Duke Energy, is a captive insurance company with the principal activity of providing Duke Energy subsidiaries with indemnification for financial losses primarily related to property, workers compensation and general liability. Duke Energy owns a 17.5% equity interest in NMC. The joint venture company has production facilities in Jubail, Saudi Arabia, where it manufactures certain petrochemicals and plastics. The company annually produces approximately 1 million metric tons each of MTBE and methanol and has the capacity to produce 50,000 metric tons of polyacetal. The main feedstocks to produce these products are natural gas and butane. Duke Energy records the investment activity of NMC using the equity method of accounting and retains 25% of NMC's board of directors' representation and voting rights. Human Capital Management Governance Our employees are critical to the success of our company. Our Human Resources organization is responsible for our human capital management strategy, which includes recruiting and hiring, onboarding and training, diversity and inclusion, workforce planning, talent and succession planning, performance management and employee development. Key areas of focus include fostering a high-performance and inclusive culture built on strong leadership and highly engaged and diverse employees, building a pipeline of skilled workers and ensuring knowledge transfer as employees retire. Our Board of Directors provides oversight on certain human capital management matters, primarily through the Compensation and People Development Committee, which is responsible for reviewing strategies and policies related to human capital management, including with respect to matters such as diversity and inclusion, employee engagement and talent development. Employees On December 31, 2022, Duke Energy had a total of 27,859 full-time, part-time and temporary employees, the majority of which were full-time employees. The total includes 5,081 employees who are represented by labor unions under various collective bargaining agreements that generally cover wages, benefits, working practices, and other terms and conditions of employment. Compensation The company seeks to attract and retain an appropriately qualified workforce and leverages Duke Energys leadership imperatives to foster a culture focused on customers, innovation, and highly engaged employees. Our compensation program is market driven and designed to link pay to performance with the goal of attracting and retaining talented employees, rewarding individual performance, and encouraging long-term commitment to our business. Our market competitive pay program includes short-term and long-term variable pay components that help to align the interests of Duke Energy to our customers and shareholders. In addition to competitive base pay, we provide eligible employees with compensation and benefits under a variety of plans and programs, including health care benefits, retirement savings, pension, health savings and flexible spending accounts, wellness, family leaves, employee assistance, as well as other benefits including a charitable matching program. The company is committed to providing market competitive, fair, and equitable compensation and regularly conducts internal pay equity reviews, and benchmarking against peer companies to ensure our pay is competitive. Diversity and

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Inclusion Duke Energy is committed to continuing to build a diverse workforce that reflects the communities we serve while strengthening a culture of inclusion where employees and customers feel respected and valued. Our Enterprise Diversity and Inclusion Council, chaired by our Chief Operating Officer in 2022, monitors the effectiveness and execution of our diversity and inclusion strategy and programs. Employee-led councils are also embedded across the company in our business units and focus on the specific diversity and inclusion needs of the business and help drive inclusion deeper into the employee experience. Leaders and individual contributors also have the opportunity to participate in voluntary diversity and inclusion training programs and facilitated conversations on insightful topics offered to further our commitment to building and enabling an inclusive work environment. Our aspirational goals include achieving workforce representation of at least 25% female and 20% racial and ethnic diversity. We continue to strive toward reaching these aspirational goals and as of December 31, 2022, our workforce consisted of approximately 23.9% female and 20.4% racial and ethnic diversity. ##TABLE_START BUSINESS ##TABLE_ENDThe company also has 10 Employee Resource Groups (ERGs), with 37 chapters and more than 6,500 employees participating. ERGs are networks of employees formed around a common dimension of diversity whose goals and objectives align with the company's goals and objectives. These groups focus on employee professional development and networking, community outreach, cultural awareness, recruiting and retention. They also serve as a resource to the company for advocacy and community outreach and improving customer service through innovation. ERG-sponsored forums include networking events, mentoring, scholarship banquets for aspiring college students, and workshops on topics such as time management, stress reduction, career planning and work-life balance. Our ERGs are open to all employees. Among other efforts, the company has developed partnerships with community organizations, community colleges and historically Black colleges and universities to support our strategy of building a diverse and highly skilled talent pipeline. Operational Excellence The foundation for our growth and success is our continued focus on operational excellence, the leading indicator of which is safety. As such, the safety of our workforce remains our top priority. The company closely monitors the total incident case rate (TICR), which is a metric based on strict OSHA definitions that measures the number of occupational injuries and illnesses per 100 employees. This objective emphasizes our focus on achieving an event-free and injury-free workplace. As an indication of our commitment to safety, we include safety metrics in both the short-term and long-term incentive plans based on the TICR for employees. Our employees delivered strong safety results in 2022, consistent with our industry-leading performance levels from 2017 through 2021. ##TABLE_START BUSINESS ##TABLE_ENDInformation about Our Executive Officers The following table sets forth the individuals who currently serve as executive officers. Executive officers serve until their successors are duly elected or appointed. ##TABLE_START Name Age (a) Current and Recent Positions Held Lynn J. Good 63 Chair, President and Chief Executive Officer. Ms. Good has served as Chair, President and Chief Executive Officer of Duke Energy since January 1, 2016, and was Vice Chairman, President and Chief Executive Officer of Duke Energy from July 2013 through December 2015. Prior to that, she served as Executive Vice President and Chief Financial Officer since 2009. Brian D. Savoy 47 Executive Vice President and Chief Financial Officer. Mr. Savoy assumed the position of Executive Vice President and Chief Financial Officer in September 2022. Prior to that, he held the position of Executive Vice President, Chief Strategy and Commercial Officer from May 2021 through August 2022; Senior Vice President, Chief Transformation and Administrative Officer from October 2019 through April 2021; Senior Vice President, Business Transformation and Technology from May 2016 through September 2019; Senior Vice President, Controller and Chief Accounting Officer from September 2013 to May 2016; Director, Forecasting and Analysis from 2009 to September 2013; and Vice President and Controller of the Commercial Power segment from 2006 to 2009. Kodwo Ghartey-Tagoe 59 Executive Vice President, Chief Legal Officer and Corporate Secretary . Mr. Ghartey-Tagoe assumed the position of Executive Vice President, Chief Legal Officer and Corporate Secretary in May 2020. He was appointed Executive Vice President and Chief Legal Officer in October 2019 after serving as President, South Carolina since 2017. Mr. Ghartey-Tagoe joined Duke Energy in 2002, and has held numerous management positions in Duke Energys Legal Department, including Duke Energy's Senior Vice President of State and Federal Regulatory Legal Support. T. Preston Gillespie 60 Executive Vice President, Chief Generation Officer and Enterprise Operational Excellence. Mr. Gillespie assumed the position of Executive Vice President, Chief Generation Officer and Enterprise Operational Excellence in January 2023. Prior to that, Mr. Gillespie served as the Chief Generation Officer since 2020. R. Alexander Glenn 57 Senior Vice President and Chief Executive Officer, Duke Energy Florida and Midwest. Mr. Glenn assumed his current position in May 2021. Prior to that, Mr. Glenn served as Senior Vice President, State and Federal Regulatory Legal Support since 2017 and as State President of Duke Energy Florida's operations from 2012 to 2017. Dhiaa M. Jamil 66 Executive Vice President and Chief Operating Officer. Mr. Jamil assumed the role of Chief Operating Officer in May 2016. Prior to his current position, he held the title Executive Vice President and President, Regulated Generation and Transmission since June 2015. Prior to that, he served as Executive Vice President and President, Regulated Generation since August 2014. He served as Executive Vice President and President of Duke Energy Nuclear from March 2013 to August 2014, and was Chief Nuclear Officer from February 2008 to February 2013. Julia S. Janson 58 Executive Vice President and Chief Executive Officer, Duke Energy Carolinas. Ms. Janson assumed her current position in May 2021. Prior to that she held the position of Executive Vice President, External Affairs and President, Carolinas Region since October 2019 and the position of Executive Vice President, External Affairs and Chief Legal Officer since November 2018. She originally assumed the position of Executive Vice President, Chief Legal Officer and Corporate Secretary in December 2012, and then assumed the responsibilities for External Affairs in February 2016. Cynthia S. Lee

56 Vice President, Chief Accounting Officer and Controller. Ms. Lee assumed her role as Vice President, Chief Accounting Officer and Controller in May 2021. Prior to that, she served as Director, Investor Relations since June 2019 and in various roles within the Corporate Controller's organization after joining the Corporation and its affiliates in 2002. Ronald R. Reising 62 Senior Vice President and Chief Human Resources Officer. Mr. Reising assumed his current position in July 2020. Prior to that, he served as Senior Vice President of Operations Support since 2014. Prior to that, he served as Chief Procurement Officer since 2006. Louis E. Renjel 49 Senior Vice President, External Affairs and Communications. Mr. Renjel assumed his current position in May 2021. Prior to that, he served as Senior Vice President of Federal Government and Corporate Affairs since 2019, and as Vice President, Federal Government Affairs and Strategic Policy since he joined Duke Energy in March 2017 until 2019. Prior to joining Duke Energy, Mr. Renjel served as Vice President of Strategic Infrastructure since 2009 for CSX Corp and as their Director of Environmental and Government Affairs from 2006 to 2008. Harry K. Sideris 52 Executive Vice President, Customer Experience, Solutions and Services. Mr. Sideris assumed his current position in October 2019. Prior to that, he served as Senior Vice President and Chief Distribution Officer since June 2018; State President, Florida from January 2017 to June 2018; Senior Vice President of Environmental Health and Safety from August 2014 to January 2017; and Vice President of Power Generations for the company's Fossil/Hydro Operations in the western portions of North Carolina and South Carolina from July 2012 to August 2014. Steven K. Young 64 Executive Vice President, Chief Strategy and Commercial Officer. Mr. Young assumed the position of Executive Vice President, Chief Strategy and Commercial Officer in September 2022. Prior to that, he held the position of Executive Vice President and Chief Financial Officer from August 2013 through August 2022; Vice President, Chief Accounting Officer and Controller, assuming the role of Chief Accounting Officer in July 2012 and the role of Controller in December 2006. ##TABLE_END(a) The ages of the officers provided are as of January 31, 2023. There are no family relationships between any of the executive officers, nor any arrangement or understanding between any executive officer and any other person involved in officer selection. ##TABLE_START BUSINESS ##TABLE_ENDEnvironmental Matters The Duke Energy Registrants are subject to federal, state and local laws and regulations with regard to air and water quality, hazardous and solid waste disposal and other environmental matters. Environmental laws and regulations affecting the Duke Energy Registrants include, but are not limited to: The Clean Air Act, as well as state laws and regulations impacting air emissions, including State Implementation Plans related to existing and new national ambient air quality standards for ozone and particulate matter. Owners and/or operators of air emission sources are responsible for obtaining permits and for annual compliance and reporting. The Clean Water Act, which requires permits for facilities that discharge wastewaters into navigable waters. The Comprehensive Environmental Response, Compensation and Liability Act, which can require any individual or entity that currently owns or in the past owned or operated a disposal site,

as well as transporters or generators of hazardous substances sent to a disposal site, to share in remediation costs. The National Environmental Policy Act, which requires federal agencies to consider potential environmental impacts in their permitting and licensing decisions, including siting approvals. Coal Ash Act, as amended, which establishes requirements regarding the use and closure of existing ash basins, the disposal of ash at active coal plants and the handling of surface water and groundwater impacts from ash basins in North Carolina. The Solid Waste Disposal Act, as amended by RCRA, which creates a framework for the proper management of hazardous and nonhazardous solid waste; classifies CCR as nonhazardous waste; and establishes standards for landfill and surface impoundment placement, design, operation and closure, groundwater monitoring, corrective action, and post-closure care. The Toxic Substances Control Act, which gives EPA the authority to require reporting, recordkeeping and testing requirements, and to place restrictions relating to chemical substances and/or mixtures, including polychlorinated biphenyls. For more information on environmental matters, see Notes 5 and 10 to the Consolidated Financial Statements, Commitments and Contingencies Environmental and "Asset Retirement Obligations," respectively, and the Other Matters section of Item 7 Management's Discussion and Analysis. Except as otherwise described in these sections, costs to comply with current federal, state and local provisions regulating the discharge of materials into the environment or other potential costs related to protecting the environment are incorporated into the routine cost structure of our various business segments and are not expected to have a material adverse effect on the competitive position, consolidated results of operations, cash flows or financial position of the Duke Energy Registrants. The "Other Matters" section of Item 7 Management's Discussion and Analysis includes more information on certain environmental regulations and a discussion of Global Climate Change including the potential impact of current and future legislation related to GHG emissions on the Duke Energy Registrants' operations. Recently passed and potential future environmental statutes and regulations could have a significant impact on the Duke Energy Registrants results of operations, cash flows or financial position. However, if and when such statutes and regulations become effective, the Duke Energy Registrants will seek appropriate regulatory recovery of costs to comply within its regulated operations. DUKE ENERGY CAROLINAS ##TABLE_START ##TABLE_ENDDuke Energy Carolinas is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina. Duke Energy Carolinas service area covers approximately 24,000 square miles and supplies electric service to 2.8 million residential, commercial and industrial customers. For information about Duke Energy Carolinas generating facilities, see Item 2, Properties. Duke Energy Carolinas is subject to the regulatory provisions of the NCUC, PSCSC, NRC and FERC. Substantially all of Duke Energy Carolinas' operations are regulated and qualify for regulatory accounting. Duke Energy Carolinas operates one reportable business segment, EUI. For additional information regarding this business segment, including financial information, see Note 3 to the

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Consolidated Financial Statements, Business Segments. PROGRESS ENERGY ##TABLE_START ##TABLE_ENDProgress Energy is a public utility holding company primarily engaged in the regulated electric utility business and is subject to regulation by the FERC. Progress Energy conducts operations through its wholly owned subsidiaries, Duke Energy Progress and Duke Energy Florida. When discussing Progress Energys financial information, it necessarily includes the results of Duke Energy Progress and Duke Energy Florida. Substantially all of Progress Energys operations are regulated and qualify for regulatory accounting. Progress Energy operates one reportable business segment, EUI. For additional information regarding this business segment, including financial information, see Note 3 to the Consolidated Financial Statements, Business Segments. DUKE ENERGY PROGRESS ##TABLE_START ##TABLE_ENDDuke Energy Progress is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina. Duke Energy Progress service area covers approximately 29,000 square miles and supplies electric service to approximately 1.7 million residential, commercial and industrial customers. For information about Duke Energy Progress generating facilities, see Item 2, Properties. Duke Energy Progress is subject to the regulatory provisions of the NCUC, PSCSC, NRC and FERC. Substantially all of Duke Energy Progress operations are regulated and qualify for regulatory accounting. Duke Energy Progress operates one reportable business segment, EUI. For additional information regarding this business segment, including financial information, see Note 3 to the Consolidated Financial Statements, Business Segments. PART I DUKE ENERGY FLORIDA ##TABLE_START ##TABLE_ENDDuke Energy Florida is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of Florida. Duke Energy Floridas service area covers approximately 13,000 square miles and supplies electric service to approximately 1.9 million residential, commercial and industrial customers. For information about Duke Energy Floridas generating facilities, see Item 2, Properties. Duke Energy Florida is subject to the regulatory provisions of the FPSC, NRC and FERC. Substantially all of Duke Energy Floridas operations are regulated and qualify for regulatory accounting. Duke Energy Florida operates one reportable business segment, EUI. For additional information regarding this business segment, including financial information, see Note 3 to the Consolidated Financial Statements, Business Segments. DUKE ENERGY OHIO ##TABLE_START ##TABLE_ENDDuke Energy Ohio is a regulated public utility primarily engaged in the transmission and distribution of electricity in portions of Ohio and Kentucky, in the generation and sale of electricity in portions of Kentucky and the transportation and sale of natural gas in portions of Ohio and Kentucky. Duke Energy Ohio also conducts competitive auctions for retail electricity supply in Ohio whereby recovery of the energy price is from retail customers. Operations in Kentucky are conducted through its wholly owned subsidiary, Duke Energy Kentucky. References herein to Duke Energy Ohio include Duke Energy Ohio and its subsidiaries, unless otherwise noted. Duke Energy Ohio is subject to the regulatory provisions of the PUCO, KPSC, PHMSA and FERC. Duke Energy Ohios service area covers approximately 3,000 square miles and supplies electric service to approximately 900,000 residential, commercial and industrial customers and provides transmission and distribution services for natural gas to approximately 550,000 customers. For information about Duke Energy Ohio's generating facilities, see Item 2, Properties. KO Transmission, a wholly owned subsidiary of Duke Energy Ohio, is an interstate pipeline company engaged in the business of transporting natural gas and is subject to the rules and regulations of FERC. KO Transmission's 90-mile pipeline supplies natural gas to Duke Energy Ohio and interconnects with the Columbia Gulf Transmission pipeline and Tennessee Gas Pipeline. An approximately 70-mile portion of KO Transmission's pipeline facilities is co-owned by Columbia Gas Transmission, LLC. KO Transmission sold all of its pipeline facilities and related real property to Columbia Gas Transmission, LLC on February 1, 2023, for approximately book value. Substantially all of Duke Energy Ohio's operations are regulated and qualify for regulatory accounting. Duke Energy Ohio has two reportable segments, EUI and GUI. For additional information on these business segments, including financial information, see Note 3 to the Consolidated Financial Statements, Business Segments. DUKE ENERGY INDIANA ##TABLE_START ##TABLE_ENDDuke Energy Indiana is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of Indiana. Duke Energy Indianas service area covers 23,000 square miles and supplies electric service to 890,000 residential, commercial and industrial customers. For information about Duke Energy Indiana's generating facilities, see Item 2, Properties. Duke Energy Indiana is subject to the regulatory provisions of the IURC and FERC. In 2021, Duke Energy executed an agreement providing for an investment in Duke Energy Indiana by GIC. The transaction was completed following two closings. For additional information, see Note 2 to the Consolidated Financial Statements, "Dispositions." Substantially all of Duke Energy Indianas operations are regulated and qualify for regulatory accounting. Duke Energy Indiana operates one reportable business segment, EUI. For additional information regarding this business segment, including financial information, see Note 3 to the Consolidated Financial Statements, Business Segments. PIEDMONT ##TABLE_START ##TABLE_ENDPiedmont is a regulated public utility primarily engaged in the distribution of natural gas to over 1.1 million residential, commercial, industrial and power generation customers in portions of North Carolina, South Carolina and Tennessee, including customers served by municipalities who are wholesale customers. For information about Piedmont's natural gas distribution facilities, see Item 2, "Properties." Piedmont is subject to the regulatory provisions of the NCUC, PSCSC, TPUC, PHMSA and FERC. Substantially all of Piedmonts operations are regulated and qualify for regulatory accounting. Piedmont operates one reportable business segment, GUI. For additional information regarding this business segment, including financial information, see Note 3 to the Consolidated Financial Statements, Business Segments. ITEM 1A. RISK FACTORS ##TABLE_START ##TABLE_ENDIn addition to other disclosures within this Form 10-K, including "Management's Discussion and Analysis of Financial Condition and Results of Operations Matters Impacting Future Results" for each registrant in Item 7, and other documents filed with the SEC from time to time, the following factors should be considered in evaluating Duke Energy and its subsidiaries. Such factors could affect actual results of operations and cause results to differ substantially from those currently expected or sought. Unless otherwise indicated, risk factors discussed below generally relate to risks associated with all of the Duke Energy Registrants. Risks identified at the Subsidiary Registrant level are generally applicable to Duke Energy. ##TABLE_START RISK FACTORS ##TABLE_ENDBUSINESS STRATEGY RISKS Duke Energys future results could be adversely affected if it is unable to implement its business strategy including achieving its carbon emissions reduction goals. Duke Energys results of operations depend, in significant part, on the extent to which it can implement its business strategy successfully. Duke Energy's clean energy transition, which includes achieving net-zero carbon emissions from electricity generation by 2050, modernizing the regulatory construct, transforming the customer experience, and digital transformation, is subject to business, policy, regulatory, technology, economic and competitive uncertainties and contingencies, many of which are beyond its control and may make those goals difficult to achieve. Federal or state policies could be enacted that restrict the availability of fuels or generation technologies, such as natural gas or nuclear power, that enable Duke Energy to reduce its carbon emissions. Supportive policies may be needed to facilitate the siting and cost recovery of transmission and distribution upgrades needed to accommodate the build out of large volumes of renewables and energy storage. Further, the approval of our state regulators will be necessary for the company to continue to retire existing carbon emitting assets or make investments in new generating capacity. The company may be constrained by the ability to procure resources or labor needed to build new generation at a reasonable price as well as to construct projects on time. In addition, new technologies that are not yet commercially available or are unproven at utility scale will likely be needed including new resources capable of following electric load over long durations such as advanced nuclear, hydrogen and long-duration storage, If these technologies are not developed or are not available at reasonable prices, or if we invest in early stage technologies that are then supplanted by technological breakthroughs, Duke Energys ability to achieve a net-zero target by 2050 at a cost-effective price could be at risk. Achieving our carbon reduction goals will require continued operation of our existing carbon-free technologies including nuclear and renewables. The rapid transition to and expansion of certain low-carbon resources, such as renewables without cost-effective storage, may challenge our ability to meet customer expectations of reliability in a carbon constrained environment. Our nuclear fleet is central to our ability to meet these objectives and customer expectations. We are continuing to seek to renew the operating licenses of the 11 reactors we operate at six nuclear stations for an additional 20 years, extending their operating lives to and beyond midcentury. Failure to receive approval from the NRC for the relicensing of any of these reactors could affect our ability to achieve a net-zero target by 2050. As a consequence, Duke Energy may not be able to fully implement or realize the anticipated results of its energy transition strategy, which may have an adverse effect on its financial condition. REGULATORY, LEGISLATIVE AND LEGAL RISKS The Duke Energy Registrants regulated utility revenues, earnings and results of operations are dependent on state legislation and regulation that affect electric generation, electric and natural gas transmission, distribution and related activities, which may limit their ability to recover costs. The Duke Energy Registrants regulated electric and natural gas utility businesses are regulated on a cost-of-service/rate-of-return basis subject to statutes and regulatory commission rules and procedures of North Carolina, South Carolina, Florida, Ohio, Tennessee, Indiana and Kentucky. If the Duke Energy Registrants regulated utility earnings exceed the returns established by the state utility commissions, retail electric and natural gas rates may be subject to review and possible reduction by the commissions, which may decrease the Duke Energy Registrants earnings. Additionally, if regulatory or legislative bodies do not allow recovery of costs incurred in providing service, or do not do so on a timely basis, the Duke Energy Registrants earnings could be negatively impacted. Differences in regulation between jurisdictions with concurrent operations, such as North Carolina and South Carolina in Duke Energy Carolinas' and Duke Energy Progress' service territory, may also result in failure to recover costs. If legislative and regulatory structures were to evolve in such a way that the Duke Energy Registrants exclusive rights to serve their regulated customers were eroded, their earnings could be negatively impacted. Federal and state regulations, laws, commercialization and reduction of costs and other efforts designed to promote and expand the use of EE measures and distributed generation technologies, such as private solar and battery storage, in Duke Energy service territories could reduce recovery of fixed costs in Duke Energy service territories or result in customers leaving the electric distribution system and an increase in customer net energy metering, which allows customers with private solar to receive bill credits for surplus power at the full retail amount. Over time, customer adoption of these technologies could result in Duke Energy not being able to fully recover the costs and investment in generation. State regulators have approved various mechanisms to stabilize natural gas utility margins, including margin decoupling in North Carolina and rate stabilization in South Carolina. State regulators have approved other margin stabilizing mechanisms that, for example, allow for recovery of margin losses associated with negotiated transactions designed to retain large volume customers that could use alternative fuels or that may otherwise directly access natural gas supply through their own connection to an interstate pipeline. If regulators decided to discontinue the Duke Energy Registrants' use of tariff mechanisms, it would negatively impact results of operations, financial position and cash flows. In addition, regulatory authorities also review whether natural gas costs are prudently incurred and can disallow the recovery of a portion of natural gas costs that the Duke Energy Registrants seek to recover from customers, which would adversely impact earnings. The rates that the Duke Energy Registrants regulated utility businesses are allowed to charge are established by state utility commissions in rate case proceedings, which may limit their ability to recover costs and earn an appropriate return on investment. The rates that the Duke Energy Registrants regulated utility businesses are allowed to charge significantly influences the results of operations, financial position and cash flows of the Duke Energy Registrants. The regulation of the rates that the regulated utility businesses charge customers is determined, in large part, by state utility commissions in rate case proceedings. Negative decisions made by these regulators, or by any court on appeal of a rate case proceeding, have, and in the future could have, a material adverse effect on the Duke Energy Registrants results of operations, financial position or cash flows and affect the ability of the Duke Energy Registrants to recover costs and an appropriate return on the significant infrastructure investments being made. ##TABLE_START RISK FACTORS ##TABLE_ENDDeregulation or restructuring in the electric industry may result in increased competition and unrecovered costs that could adversely affect the Duke Energy Registrants results of operations, financial position or cash flows and their utility businesses. Increased competition resulting from deregulation or restructuring legislation could have a significant adverse impact on the Duke Energy Registrants results of operations, financial position or cash flows and their utility businesses. If the retail jurisdictions served by the Duke Energy Registrants become subject to deregulation, the impairment of assets, loss of retail customers, lower profit margins or increased costs of capital, and recovery of stranded costs could have a significant adverse financial impact on the Duke Energy Registrants. Stranded costs primarily include the generation assets of the Duke Energy Registrants whose value in a competitive marketplace may be less than their current book value, as well as above-market purchased power commitments from QFs from whom the Duke Energy Registrants are legally obligated to purchase energy at an avoided cost rate under PURPA. The Duke Energy Registrants cannot predict the extent and timing of entry by additional competitors into the electric markets. The Duke Energy Registrants cannot predict if or when they will be subject to changes in legislation or regulation, nor can they predict the impact of these changes on their results of operations, financial position or cash flows. The Duke Energy Registrants businesses are subject to extensive federal regulation and a wide variety of laws and governmental policies, including taxes and environmental regulations, that may change over time in ways that affect operations and costs. The Duke Energy Registrants are subject to regulations under a wide variety of U.S. federal and state regulations and policies, including by FERC, NRC, EPA and various other federal agencies as well as the North American Electric Reliability Corporation. Regulation affects almost every aspect of the Duke Energy Registrants businesses, including, among other things, their ability to: take fundamental business management actions; determine the terms and rates of transmission and distribution services; make acquisitions; issue equity or debt securities; engage in transactions with other subsidiaries and affiliates; and pay dividends upstream to the Duke Energy Registrants. Changes to federal regulations are continuous and ongoing. There can be no assurance that laws, regulations and policies will not be changed in ways that result in material modifications of business models and objectives or affect returns on investment by restricting activities and products, subjecting them to escalating costs, causing delays, or prohibiting them outright. The Duke Energy Registrants are subject to numerous environmental laws and regulations requiring significant capital expenditures that can increase the cost of operations, and which may impact or limit business plans, or cause exposure to environmental liabilities. The Duke Energy Registrants are subject to numerous environmental laws and regulations affecting many aspects of their present and future operations, including CCRs, air emissions, water quality, wastewater discharges, solid waste and hazardous waste. These laws and regulations can result in increased capital, operating and other costs. These laws and regulations generally require the Duke Energy Registrants to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Compliance with environmental laws and regulations can require significant expenditures, including expenditures for cleanup costs and damages arising from contaminated properties. Failure to comply with environmental regulations may result in the imposition of fines, penalties and injunctive measures affecting operating assets. The steps the Duke Energy Registrants could be required to take to ensure their facilities are in compliance could be prohibitively expensive. As a result, the Duke Energy Registrants may be required to shut down or alter the operation of their facilities, which may cause the Duke Energy Registrants to incur losses. Further, the Duke Energy Registrants may not be successful in recovering capital and operating costs incurred to comply with new environmental regulations through existing regulatory rate structures and their contracts with customers. Also, the Duke Energy Registrants may not be able to obtain or maintain from time to time all required environmental regulatory approvals for their operating assets or development projects. Delays in obtaining any required environmental regulatory approvals, failure to obtain and comply with them or changes in environmental laws or regulations to more stringent compliance levels could result in additional costs of operation for existing facilities or development of new facilities being prevented, delayed or subject to additional costs. Although it is not expected that the costs to comply with current environmental regulations will have a material adverse effect on the Duke Energy Registrants results of operations, financial position and cash flows due to regulatory cost recovery, the Duke Energy Registrants are at risk that the costs of complying with environmental regulations in the future will have such an effect. The EPA has enacted or proposed federal regulations governing the management of cooling water intake structures, wastewater and CO_2 emissions. New state legislation could impose carbon reduction goals that are more aggressive than the company's plans. These regulations may require the Duke Energy Registrants to make additional capital expenditures and increase operating and maintenance costs. The Duke Energy Registrants' operations, capital expenditures and financial results may be affected by regulatory changes related to the impacts of global climate change. There is continued concern, and increasing activism, both nationally and internationally, about climate change. The EPA and state regulators have, and may adopt and implement, additional regulations to restrict emissions of GHGs to address global climate change. Certain local and state jurisdictions have also enacted laws to restrict or prevent new natural gas infrastructure. Increased regulation of GHG emissions could impose significant additional costs on the Duke Energy Registrants' electric and natural gas operations, their suppliers and customers and affect demand for energy conservation and renewable products, which could impact both our electric and natural gas businesses. Regulatory changes could also result in generation facilities to be retired earlier than planned to meet our net-zero 2050 goal. Though we would plan to seek cost recovery for investments related to GHG emissions reductions through regulatory rate structures, changes in the regulatory climate could result in the delay in or failure to fully recover such costs and investment in generation. OPERATIONAL RISKS The Duke Energy Registrants results of operations may be negatively affected by overall market, economic and other conditions that are beyond their control. Sustained downturns or sluggishness in the economy generally affect the markets in which the Duke Energy Registrants operate and negatively influence operations. Declines in demand for electricity or natural gas as a result of economic downturns in the Duke Energy Registrants regulated service territories will reduce overall sales and lessen cash flows, especially as industrial customers reduce production and, therefore, consumption of electricity and the use of natural gas. Although the Duke Energy Registrants regulated electric and natural gas businesses are subject to regulated allowable rates of return and recovery of certain costs, such as fuel and purchased natural gas costs, under periodic adjustment clauses, overall declines in electricity or natural gas sold as a result of economic downturn or recession could reduce revenues and cash flows, thereby diminishing results of operations. ##TABLE_START RISK FACTORS ##TABLE_ENDA continuation of adverse economic conditions including economic downturn or high commodity prices could also negatively impact the financial stability of certain of our customers and result in their inability to pay for electric and natural gas services. This could lead to increased bad debt expense and higher allowance for doubtful account reserves for the Duke Energy Registrants and result in delayed or unrecovered operating costs and lower financial results. Additionally, prolonged economic downturns that negatively impact the Duke Energy Registrants results of operations and cash flows could result in future material impairment charges to write-down the carrying value of certain assets, including goodwill, to their respective fair values. The Duke Energy Registrants also monitor the impacts of inflation on the procurement of goods and services and seek to minimize its effects in future periods through pricing strategies, productivity improvements, and cost reductions. Rapidly rising prices as a result of inflation or other factors may impact the ability of the company to recover costs timely or execute on its business strategy including the achievement of growth objectives. The Duke Energy Registrants sell electricity into the spot market or other competitive power markets on a contractual basis. With respect to such transactions, the Duke Energy Registrants are not guaranteed any rate of return on their capital investments through mandated rates, and revenues and results of operations are likely to depend, in large part, upon prevailing market prices. These market prices may fluctuate substantially over relatively short periods of time and could negatively impact the company's ability to accurately forecast the financial impact or reduce the Duke Energy Registrants revenues and margins, thereby diminishing results of operations. Factors that could impact sales volumes, generation of electricity and market prices at which the Duke Energy Registrants are able to sell electricity and natural gas are as follows: weather conditions, including abnormally mild winter or summer weather that cause lower energy or natural gas usage for heating or cooling purposes, as applicable, and periods of low rainfall that decrease the ability to operate facilities in an economical manner; supply of and demand for energy commodities; transmission or transportation constraints or inefficiencies that impact nonregulated energy operations; availability of purchased power; availability of competitively priced alternative energy sources, which are preferred by some customers over electricity produced from coal, nuclear or natural gas plants, and customer usage of energy-efficient equipment that reduces energy demand; natural gas, crude oil and refined products production levels and prices; ability to procure satisfactory levels of inventory, including materials, supplies, and fuel such as coal, natural gas and uranium; and capacity and transmission service into, or out of, the Duke Energy Registrants markets. Natural disasters or operational accidents may adversely affect the Duke Energy Registrants operating results. Natural disasters or operational accidents within the company or industry (such as forest fires, earthquakes, hurricanes or natural gas transmission pipeline explosions) could have direct or indirect impacts to the Duke Energy Registrants or to key contractors and suppliers. Further, the generation of electricity and the transportation and storage of natural gas involve inherent operating risks that may result in accidents involving serious injury or loss of life, environmental damage or property damage. Such events could impact the Duke Energy Registrants through changes to policies, laws and regulations whose compliance costs have a significant impact on the Duke Energy Registrants results of operations, financial position and cash flows. In addition, if a serious operational accident were to occur, existing insurance policies may not cover all of the potential exposures or the actual amount of loss incurred, including potential litigation awards. Any losses not covered by insurance, or any increases in the cost of applicable insurance as a result of such accident, could have a material adverse effect on the results of operations, financial position, cash flows and reputation of the Duke Energy Registrants. The reputation and financial condition of the Duke Energy Registrants could be negatively impacted due to their obligations to comply with federal and state regulations, laws, and other legal requirements that govern the operations, assessments, storage, closure, remediation, disposal and monitoring relating to CCR, the high costs and new rate impacts associated with implementing these new CCR-related requirements and the strategies and methods necessary to implement these requirements in compliance with these legal obligations. As a result of electricity produced for decades at coal-fired power plants, the Duke Energy Registrants manage large amounts of CCR that are primarily stored in dry storage within landfills or combined with water in surface impoundments, all in compliance with applicable regulatory requirements. A CCR-related operational incident could have a material adverse impact on the reputation and results of operations, financial position and cash flows of the Duke Energy Registrants. During 2015, EPA regulations were enacted related to the management of CCR from power plants. These regulations classify CCR as nonhazardous waste under the RCRA and apply to electric generating sites with new and existing landfills and, new and existing surface impoundments, and establish requirements regarding landfill design, structural integrity design and assessment criteria for surface impoundments, groundwater monitoring, protection and remedial procedures and other operational and reporting procedures for the disposal and management of CCR. In addition to the federal regulations, CCR landfills and surface impoundments will continue to be regulated by existing state laws, regulations and permits, as well as additional legal requirements that may be imposed in the future, such as the settlement reached with the NCDEQ to excavate seven of the nine remaining coal ash basins in North Carolina, and partially excavate the remaining two, and the EPA's January 11, 2022, issuance of a letter interpreting the CCR Rule, including its applicability and closure provisions. These federal and state laws, regulations and other legal requirements may require or result in additional expenditures, including increased operating and maintenance costs, which could affect the results of operations, financial position and cash flows of the Duke Energy Registrants. The Duke Energy Registrants will continue to seek full cost recovery for expenditures through the normal ratemaking process with state and federal utility commissions, who permit recovery in rates of necessary and prudently incurred costs associated with the Duke Energy Registrants regulated operations, and through other wholesale contracts with terms that contemplate recovery of such costs, although there is no guarantee of full cost recovery. In addition, the timing for and amount of recovery of such costs could have a material adverse impact on Duke Energy's cash flows. ##TABLE_START RISK FACTORS ##TABLE_ENDThe Duke Energy Registrants have recognized significant AROs related to these CCR-related requirements. Closure activities began in 2015 at the four sites specified as high priority by the Coal Ash Act and at the W.S. Lee Steam Station site in South Carolina in connection with other legal requirements. Excavation at these sites involves movement of CCR materials to off-site locations for use as structural fill, to appropriately engineered off-site or on-site lined landfills or conversion of the ash for beneficial use. Duke Energy has completed excavation of coal ash at the four high-priority North Carolina sites. At other sites, planning and closure methods have been studied and factored into the estimated retirement and management costs, and closure activities have commenced. As the closure and CCR management work progresses and final closure plans and corrective action measures are developed and approved at each site, the scope and complexity of work and the amount of CCR material could be greater than estimates and could, therefore, materially increase compliance expenditures and rate impacts. The Duke Energy Registrants results of operations, financial position and cash flows may be negatively affected by a lack of growth or slower growth in the number of customers, or decline in customer demand or number of customers. Growth in customer accounts and growth of customer usage each directly influence demand for electricity and natural gas and the need for additional power generation and delivery facilities. Customer growth and customer usage are affected by several factors outside the control of the Duke Energy Registrants, such as mandated EE measures, demand-side management goals, distributed generation resources and economic and demographic conditions, such as inflation and interest rate volatility, population changes, job and income growth, housing starts, new business formation and the overall level of economic activity. In addition, certain regulatory and legislative bodies have passed legislation implementing the extension of certain tax credits to be used toward the costs of residential solar installation or have introduced or are considering requirements and/or incentives to reduce energy consumption by certain dates in response to concerns related to climate change. Additionally, technological advances driven by federal laws mandating new levels of EE in end-use electric and natural gas devices or other improvements in or applications of technology could lead to declines in per capita energy consumption. Advances in distributed generation technologies that produce power, including fuel cells, microturbines, wind turbines and solar cells, may reduce the cost of alternative methods of producing power to a level competitive with central power station electric production utilized by the Duke Energy Registrants. In addition, the electrification of buildings and appliances currently relying on natural gas could reduce the number of customers in our natural gas distribution business. Some or all of these factors could result in a lack of growth or decline in customer demand for electricity or number of customers and may cause the failure of the Duke Energy Registrants to fully realize anticipated benefits from significant capital investments and expenditures, which could have a material adverse effect on their results of operations, financial position and cash flows. Furthermore, the Duke Energy Registrants currently have EE riders in place to recover the cost of EE programs in North Carolina, South Carolina, Florida, Indiana, Ohio and Kentucky. Should the Duke Energy Registrants be required to invest in conservation measures that result in reduced sales from effective conservation, regulatory lag in adjusting rates for the impact of these measures could have a negative financial impact. The Duke Energy Registrants future results of operations may be impacted by changing expectations and demands including heightened emphasis on environmental, social and governance concerns. Duke Energys ability to execute its strategy and achieve anticipated financial outcomes are influenced by the expectations of our customers, regulators, investors, and stakeholders. Those expectations are based in part on the core fundamentals of reliability and affordability but are also increasingly focused on our ability to meet rapidly changing demands for new and varied products, services and offerings. Additionally, the risks of global climate change continues to shape our customers sustainability goals and energy needs as well as the investment and financing criteria of investors. Failure to meet these increasing expectations or to adequately address the risks and external pressures from regulators, customers, investors and other stakeholders may impact Duke Energys reputation and affect its ability to achieve favorable outcomes in future rate cases and the results of operations for the Duke Energy Registrants. Furthermore, the increasing use of social media may accelerate and increase the potential scope of negative publicity we might receive and could increase the negative impact on our reputation, business, results of operations, and financial condition. As it relates to electric generation, a diversified fleet with increasingly clean generation resources may facilitate more efficient financing and lower costs. Conversely, jurisdictions utilizing more carbon-intensive generation such as coal may experience difficulty attracting certain investors and obtaining the most economical financing terms available. Furthermore, with this heightened emphasis on environmental, social, and governance concerns, and climate change in particular, there is an increased risk of litigation, activism, and legislation from groups both in support of and opposed to various environmental, social and governance initiatives, which could cause delays and increase the costs of our clean energy transition. The Duke Energy Registrants operating results may fluctuate on a seasonal and quarterly basis and can be negatively affected by changes in weather conditions and severe weather, including extreme weather conditions and changes in weather patterns from climate change. Electric power generation and natural gas distribution are generally seasonal businesses. In most parts of the U.S., the demand for power peaks during the warmer summer months, with market prices also typically peaking at that time. In other areas, demand for power peaks during the winter. Demand for natural gas peaks during the winter months. Further, changing frequency or magnitude of extreme weather conditions such as hurricanes, droughts, heat waves, winter storms and severe weather, including from climate change, could cause these seasonal fluctuations to be more pronounced. As a result, the overall operating results of the Duke Energy Registrants businesses may fluctuate substantially on a seasonal and quarterly basis and thus make period-to-period comparison less relevant. Sustained severe drought conditions could impact generation by hydroelectric plants, as well as fossil and nuclear plant operations, as these facilities use water for cooling purposes and for the operation of environmental compliance equipment. Furthermore, destruction caused by severe weather events, such as hurricanes, flooding, tornadoes, severe thunderstorms, snow and ice storms, including from climate change, can result in lost operating revenues due to outages, property damage, including downed transmission and distribution lines, and additional and unexpected expenses to mitigate storm damage. The cost of storm restoration efforts may not be fully recoverable through the regulatory process. ##TABLE_START RISK FACTORS ##TABLE_ENDThe Duke Energy Registrants sales may decrease if they are unable to gain adequate, reliable and affordable access to transmission assets. The Duke Energy Registrants depend on transmission and distribution facilities owned and operated by utilities and other energy companies to deliver electricity sold to the wholesale market. In addition, the growth of renewables and energy storage will put strains on existing transmission assets and require transmission and distribution upgrades. The FERCs power transmission regulations require wholesale electric transmission services to be offered on an open-access, non-discriminatory basis. If transmission is disrupted, or if transmission capacity is inadequate, the Duke Energy Registrants ability to sell and deliver products may be hindered. The different regional power markets have changing regulatory structures, which could affect growth and performance in these regions. In addition, the ISOs who oversee the transmission systems in regional power markets have imposed in the past, and may impose in the future, price limitations and other mechanisms to address volatility in the power markets. These types of price limitations and other mechanisms may adversely impact the profitability of the Duke Energy Registrants wholesale power marketing business. The availability of adequate interstate pipeline transportation capacity and natural gas supply may decrease. The Duke Energy Registrants purchase almost all of their natural gas supply from interstate sources that must be transported to the applicable service territories. Interstate pipeline companies transport the natural gas to the Duke Energy Registrants' systems under firm service agreements that are designed to meet the requirements of their core markets. A significant disruption to interstate pipelines capacity or reduction in natural gas supply due to events including, but not limited to, operational failures or disruptions, hurricanes, tornadoes, floods, freeze off of natural gas wells, terrorist or cyberattacks or other acts of war or legislative or regulatory actions or requirements, including remediation related to integrity inspections or regulations and laws enacted to address climate change, could reduce the normal interstate supply of natural gas and thereby reduce earnings. Moreover, if additional natural gas infrastructure, including, but not limited to, exploration and drilling rigs and platforms, processing and gathering systems, offshore pipelines, interstate pipelines and storage, cannot be built at a pace that meets demand, then growth opportunities could be limited. Fluctuations in commodity prices or availability may adversely affect various aspects of the Duke Energy Registrants operations as well as their results of operations, financial position and cash flows. The Duke Energy Registrants are exposed to the effects of market fluctuations in the price of natural gas, coal, fuel oil, nuclear fuel, electricity and other energy-related commodities as a result of their ownership of energy-related assets. Fuel costs are recovered primarily through cost recovery clauses, subject to the approval of state utility commissions. Additionally, the Duke Energy Registrants are exposed to risk that counterparties will not be able to fulfill their obligations. Disruption in the delivery of fuel, including disruptions as a result of, among other things, bankruptcies, transportation delays, weather, labor relations, force majeure events or environmental regulations affecting any of these fuel suppliers, could limit the Duke Energy Registrants' ability to operate their facilities. Should counterparties fail to perform, the Duke Energy Registrants might be forced to replace the underlying commitment at prevailing market prices possibly resulting in losses in addition to the amounts, if any, already paid to the counterparties. Certain of the Duke Energy Registrants hedge agreements may result in the receipt of, or posting of, collateral with counterparties, depending on the daily market-based calculation of financial exposure of the derivative positions. Fluctuations in commodity prices that lead to the return of collateral received and/or the posting of collateral with counterparties could negatively impact liquidity. Downgrades in the Duke Energy Registrants credit ratings could lead to additional collateral posting requirements. The Duke Energy Registrants continually monitor derivative positions in relation to market price activity. Cyberattacks and data security breaches could adversely affect the Duke Energy Registrants' businesses. Cybersecurity risks have increased in recent years as a result of the proliferation of new technologies and the increased sophistication, magnitude and frequency of cyberattacks and data security breaches. Duke Energy relies on the continued operation of sophisticated digital information technology systems and network infrastructure, which are part of an interconnected regional grid. Additionally, connectivity to the internet continues to increase through grid modernization and other operational excellence initiatives. Because of the critical nature of the infrastructure, increased connectivity to the internet and technology systems inherent vulnerability to disability or failures due to hacking, viruses, acts of war or terrorism or other types of data security breaches, the Duke Energy Registrants face a heightened risk of cyberattack from foreign or domestic sources and have been subject, and will likely continue to be subject, to attempts to gain unauthorized access to information and/or information systems or to disrupt utility operations through computer viruses and phishing attempts either directly or indirectly through its material vendors or related third parties. In the event of a significant cybersecurity breach on either the Duke Energy Registrants or with one of our material vendors or related third parties, the Duke Energy Registrants could (i) have business operations disrupted, including the disruption of the operation of our natural gas and electric assets and the power grid, theft of confidential company, employee, retiree, shareholder, vendor or customer information, and general business systems and process interruption or compromise, including preventing the Duke Energy Registrants from servicing customers, collecting revenues or the recording, processing and/or reporting financial information correctly, (ii) experience substantial loss of revenues, repair and restoration costs, penalties and costs for lack of compliance with relevant regulations, implementation costs for additional security measures to avert future cyberattacks and other financial loss and (iii) be subject to increased regulation, litigation and reputational damage. While Duke Energy maintains insurance relating to cybersecurity events, such insurance is subject to a number of exclusions and may be insufficient to offset any losses, costs or damage experienced. Also, the market for cybersecurity insurance is relatively new and coverage available for cybersecurity events is evolving as the industry matures. ##TABLE_START RISK FACTORS ##TABLE_ENDThe Duke Energy Registrants are subject to standards enacted by the North American Electric Reliability Corporation and enforced by FERC regarding protection of the physical and cybersecurity of critical infrastructure assets required for operating North America's bulk electric system. The Duke Energy Registrants are also subject to regulations set by the Nuclear Regulatory Commission regarding the protection of digital computer and communication systems and networks required for the operation of nuclear power plants. The Duke Energy Registrants that operate designated critical pipelines that transport natural gas are also subject to security directives issued by the Department of Homeland Security's Transportation Security Administration (TSA) requiring such registrants to implement specific cybersecurity mitigation measures. While the Duke Energy Registrants believe they are in compliance with, or, in the case of recent TSA security directives, are in the process of implementing such standards and regulations, the Duke Energy Registrants have from time to time been, and may in the future be, found to be in violation of such standards and regulations. In addition, compliance with or changes in the applicable standards and regulations may subject the Duke Energy Registrants to higher operating costs and/or increased capital expenditures as well as substantial fines for non-compliance. The Duke Energy Registrants operations have been and may be affected by pandemic health events, including COVID-19, in ways listed below and in ways the Duke Energy Registrants cannot predict at this time. The COVID-19 pandemic and efforts to respond to it have resulted in widespread adverse consequences on the global economy and on the Duke Energy Registrants customers, third-party vendors, and other parties with whom we do business. If the COVID-19 pandemic or other health epidemics and outbreaks that may occur are significantly prolonged, it could impact the Duke Energy Registrants' business strategy, results of operations, financial position and cash flows in the future as a result of delays in rate cases or other legal proceedings, an inability to obtain labor or equipment necessary for the construction of large capital projects, an inability to procure satisfactory levels of fuels or other necessary equipment for the continued production of electricity and delivery of natural gas, and the health and availability of our critical personnel and their ability to perform business functions. Duke Energy Ohios and Duke Energy Indianas membership in an RTO presents risks that could have a material adverse effect on their results of operations, financial position and cash flows. The rules governing the various regional power markets may change, which could affect Duke Energy Ohios and Duke Energy Indianas costs and/or revenues. To the degree Duke Energy Ohio and Duke Energy Indiana incur significant additional fees and increased costs to participate in an RTO, their results of operations may be impacted. Duke Energy Ohio and Duke Energy Indiana may be allocated a portion of the cost of transmission facilities built by others due to changes in RTO transmission rate design. Duke Energy Ohio and Duke Energy Indiana may be required to expand their transmission system according to decisions made by an RTO rather than their own internal planning process. In addition, RTOs have been developing rules associated with the allocation and methodology of assigning costs associated with improved transmission reliability, reduced transmission congestion and firm transmission rights that may have a financial impact on the results of operations, financial position and cash flows of Duke Energy Ohio and Duke Energy Indiana. As members of an RTO, Duke Energy Ohio and Duke Energy Indiana are subject to certain additional risks, including those associated with the allocation among RTO members, of losses caused by unreimbursed defaults of other participants in the RTO markets and those associated with complaint cases filed against an RTO that may seek refunds of revenues previously earned by RTO members. The Duke Energy Registrants may not recover costs incurred to begin construction on projects that are canceled. Duke Energys long-term strategy requires the construction of new projects, either wholly owned or partially owned, which involve a number of risks, including construction delays, delays in or failure to receive required regulatory approvals and/or sitting or environmental permits, nonperformance by equipment and other third-party suppliers, and increases in equipment and labor costs. To limit the risks of these construction projects, the Duke Energy Registrants enter into equipment purchase orders and construction contracts and incur engineering and design service costs in advance of receiving necessary regulatory approvals and/or siting or environmental permits. If any of these projects are canceled for any reason, including failure to receive necessary regulatory approvals and/or siting or environmental permits, significant cancellation penalties under the equipment purchase orders and construction contracts could occur. In addition, if any construction work or investments have been recorded as an asset, an impairment may need to be recorded in the event the project is canceled. The Duke Energy Registrants are subject to risks associated with their ability to obtain adequate insurance at acceptable costs. The financial condition of some insurance companies, actual or threatened physical or cyberattacks, and natural disasters, among other things, could have disruptive effects on insurance markets. The availability of insurance covering risks that the Duke Energy Registrants and their respective competitors typically insure against may decrease, and the insurance that the Duke Energy Registrants are able to obtain may have higher deductibles, higher premiums, and more restrictive policy terms. Further, the insurance policies may not cover all of the potential exposures or the actual amount of loss incurred. Any losses not covered by insurance, or any increases in the cost of applicable insurance, could adversely affect the results of operations, financial position or cash flows of the affected Duke Energy Registrant. Our business could be negatively affected as a result of actions of activist shareholders. While we strive to maintain constructive communications with our shareholders, activist shareholders may, from time to time, engage in proxy solicitations or advance shareholder proposals, or otherwise attempt to affect changes and assert influence on our Board and management. Perceived uncertainties as to the future direction or governance of the company may cause concern to our current or potential regulators, vendors or strategic partners, or make it more difficult to execute on our strategy or to attract and retain qualified personnel, which may have a material impact on our business and operating results. In addition, actions such as those described above could cause fluctuations in the trading price of our common stock, based on temporary or speculative market perceptions or other factors that do not necessarily reflect the underlying fundamentals and prospects of our business. ##TABLE_START RISK FACTORS ##TABLE_ENDNUCLEAR GENERATION RISKS Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida may incur substantial costs and liabilities due to their ownership and operation of nuclear generating facilities. Ownership interests in and operation of nuclear stations by Duke Energy Carolinas, Duke Energy Progress and

Duke Energy Florida subject them to various risks. These risks include, among other things: the potential harmful effects on the environment and human health resulting from the current or past operation of nuclear facilities and the storage, handling and disposal of radioactive materials; limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations; and uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives. Ownership and operation of nuclear generation facilities requires compliance with licensing and safety-related requirements imposed by the NRC. In the event of non-compliance, the NRC may increase regulatory oversight, impose fines or shut down a unit depending upon its assessment of the severity of the situation. Revised security and safety requirements promulgated by the NRC, which could be prompted by, among other things, events within or outside of the control of Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida, such as a serious nuclear incident at a facility owned by a third party, could necessitate substantial capital and other expenditures, as well as assessments to cover third-party losses. In addition, if a serious nuclear incident were to occur, it could have a material adverse effect on the results of operations, financial position, cash flows and reputation of the Duke Energy Registrants. LIQUIDITY, CAPITAL REQUIREMENTS AND COMMON STOCK RISKS The Duke Energy Registrants rely on access to short-term borrowings and longer-term debt and equity markets to finance their capital requirements and support their liquidity needs. Access to those markets can be adversely affected by a number of conditions, many of which are beyond the Duke Energy Registrants control. The Duke Energy Registrants businesses are significantly financed through issuances of debt and equity. The maturity and repayment profile of debt used to finance investments often does not correlate to cash flows from their assets. Accordingly, as a source of liquidity for capital requirements not satisfied by the cash flows from their operations and to fund investments originally financed through debt instruments with disparate maturities, the Duke Energy Registrants rely on access to short-term money markets as well as longer-term capital markets. The Subsidiary Registrants also rely on access to short-term intercompany borrowings. If the Duke Energy Registrants are not able to access debt or equity at competitive rates or at all, the ability to finance their operations and implement their strategy and business plan as scheduled could be adversely affected. An inability to access debt and equity may limit the Duke Energy Registrants ability to pursue improvements or acquisitions that they may otherwise rely on for future growth. Market disruptions may increase the cost of borrowing or adversely affect the ability to access one or more financial markets. Such disruptions could include: economic downturns, unfavorable capital market conditions, market prices for natural gas and coal, geopolitical risks, actual or threatened terrorist attacks, or the overall health of the energy industry. Additionally, rapidly rising interest rates could impact the ability to affordably finance the capital plan or increase rates to customers and could have an impact on our ability to execute on our clean energy transition. The availability of credit under Duke Energys Master Credit Facility depends upon the ability of the banks providing commitments under the facility to provide funds when their obligations to do so arise. Systemic risk of the banking system and the financial markets could prevent a bank from meeting its obligations under the facility agreement. Duke Energy maintains a revolving credit facility to provide backup for its commercial paper program and letters of credit to support variable rate demand tax-exempt bonds that may be put to the Duke Energy Registrant issuer at the option of the holder. The facility includes borrowing sublimits for the Duke Energy Registrants, each of whom is a party to the credit facility, and financial covenants that limit the amount of debt that can be outstanding as a percentage of the total capital for the specific entity. Failure to maintain these covenants at a particular entity could preclude Duke Energy from issuing commercial paper or the Duke Energy Registrants from issuing letters of credit or borrowing under the Master Credit Facility. The Duke Energy Registrants must meet credit quality standards and there is no assurance they will maintain investment grade credit ratings. If the Duke Energy Registrants are unable to maintain investment grade credit ratings, they would be required under credit agreements to provide collateral in the form of letters of credit or cash, which may materially adversely affect their liquidity. Each of the Duke Energy Registrants senior long-term debt issuances is currently rated investment grade by various rating agencies. The Duke Energy Registrants cannot ensure their senior long-term debt will be rated investment grade in the future. If the rating agencies were to rate the Duke Energy Registrants below investment grade, borrowing costs would increase, perhaps significantly. In addition, the potential pool of investors and funding sources would likely decrease. Further, if the short-term debt rating were to fall, access to the commercial paper market could be significantly limited. A downgrade below investment grade could also require the posting of additional collateral in the form of letters of credit or cash under various credit, commodity and capacity agreements and trigger termination clauses in some interest rate derivative agreements, which would require cash payments. All of these events would likely reduce the Duke Energy Registrants liquidity and profitability and could have a material effect on their results of operations, financial position and cash flows. Non-compliance with debt covenants or conditions could adversely affect the Duke Energy Registrants ability to execute future borrowings. The Duke Energy Registrants debt and credit agreements contain various financial and other covenants. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. ##TABLE_START RISK FACTORS ##TABLE_ENDMarket performance and other changes may decrease the value of the NDTF investments of Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida, which then could require significant additional funding. Ownership and operation of nuclear generation facilities also requires the maintenance of funded trusts that are intended to pay for the decommissioning costs of the respective nuclear power plants. The performance of the capital markets affects the values of the assets held in trust to satisfy these future obligations. Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida have significant obligations in this area and hold significant assets in these trusts. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below projected rates of return. Although a number of factors impact funding requirements, a decline in the market value of the assets may increase the funding requirements of the obligations for decommissioning nuclear plants. If Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida are unable to successfully manage their NDTF assets, their results of operations, financial position and cash flows could be negatively affected. Poor investment performance of the Duke Energy pension plan holdings and other factors impacting pension plan costs could unfavorably impact the Duke Energy Registrants liquidity and results of operations. The costs of providing non-contributory defined benefit pension plans are dependent upon a number of factors, such as the rates of return on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plans, future government regulation and required or voluntary contributions made to the plans. The Subsidiary Registrants are allocated their proportionate share of the cost and obligations related to these plans. Without sustained growth in the pension investments over time to increase the value of plan assets and, depending upon the other factors impacting costs as listed above, Duke Energy could be required to fund its plans with significant amounts of cash. Such cash funding obligations, and the Subsidiary Registrants proportionate share of such cash funding obligations, could have a material adverse impact on the Duke Energy Registrants results of operations, financial position and cash flows. Duke Energy is a holding company and depends on the cash flows from its subsidiaries to meet its financial obligations. Because Duke Energy is a holding company with no operations or cash flows of its own, its ability to meet its financial obligations, including making interest and principal payments on outstanding indebtedness and to pay dividends on its common stock, is primarily dependent on the net income and cash flows of its subsidiaries and the ability of those subsidiaries to pay upstream dividends or to repay borrowed funds. Prior to funding Duke Energy, its subsidiaries have regulatory restrictions and financial obligations that must be satisfied. These subsidiaries are separate legal entities and have no obligation to provide Duke Energy with funds. In addition, Duke Energy may provide capital contributions or debt financing to its subsidiaries under certain circumstances, which would reduce the funds available to meet its financial obligations, including making interest and principal payments on outstanding indebtedness and to pay dividends on Duke Energys common stock. GENERAL RISKS The failure of Duke Energy information technology systems, or the failure to enhance existing information technology systems and implement new technology, could adversely affect the Duke Energy Registrants businesses. Duke Energys operations are dependent upon the proper functioning of its internal systems, including the information technology systems that support our underlying business processes. Any significant failure or malfunction of such information technology systems may result in disruptions of our operations. In the ordinary course of business, we rely on information technology systems, including the internet and third-party hosted services, to support a variety of business processes and activities and to store sensitive data, including (i) intellectual property, (ii) proprietary business information, (iii) personally identifiable information of our customers, employees, retirees and shareholders and (iv) data with respect to invoicing and the collection of payments, accounting, procurement, and supply chain activities. Our information technology systems are dependent upon global communications and cloud service providers, as well as their respective vendors, many of whom have at some point experienced significant system failures and outages in the past and may experience such failures and outages in the future. These providers systems are susceptible to cybersecurity and data breaches, outages from fire, floods, power loss, telecommunications failures, break-ins and similar events. Failure to prevent or mitigate data loss from system failures or outages could materially affect the results of operations, financial position and cash flows of the Duke Energy Registrants. In addition to maintaining our current information technology systems, Duke Energy believes the digital transformation of its business is key to driving internal efficiencies as well as providing additional capabilities to customers. Duke Energys information technology systems are critical to cost-effective, reliable daily operations and our ability to effectively serve our customers. We expect our customers to continue to demand more sophisticated technology-driven solutions and we must enhance or replace our information technology systems in response. This involves significant development and implementation costs to keep pace with changing technologies and customer demand. If we fail to successfully implement critical technology, or if it does not provide the anticipated benefits or meet customer demands, such failure could materially adversely affect our business strategy as well as impact the results of operations, financial position and cash flows of the Duke Energy Registrants. Potential terrorist activities, or military or other actions, could adversely affect the Duke Energy Registrants businesses. The continued threat of terrorism and the impact of retaliatory military and other action by the U.S. and its allies may lead to increased political, economic and financial market instability and volatility in prices for natural gas and oil, which may have material adverse effects in ways the Duke Energy Registrants cannot predict at this time. In addition, future acts of terrorism and possible reprisals as a consequence of action by the U.S. and its allies could be directed against companies operating in the U.S. Information technology systems, transportation systems for our fuel sources including natural gas pipelines, transmission and distribution and generation facilities such as nuclear plants could be potential targets of terrorist activities or harmful activities by individuals or groups that could have a material adverse effect on Duke Energy Registrants' businesses. In particular, the Duke Energy Registrants may experience increased capital and operating costs to implement increased security for their information technology systems, transmission and distribution and generation facilities, including nuclear power plants under the NRCs design basis threat requirements. These increased costs could include additional physical plant security and security personnel or additional capability following a terrorist incident. ##TABLE_START RISK FACTORS ##TABLE_ENDFailure to attract and retain an appropriately qualified workforce could unfavorably impact the Duke Energy Registrants results of operations. Certain events, such as an aging workforce, mismatch of skill set or complement to future needs, or unavailability of contract resources may lead to operating challenges and increased costs. The challenges include lack of resources, loss of knowledge base and the lengthy time required for skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, may increase. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to new employees, or future availability and cost of contract labor may adversely affect the ability to manage and operate the business, especially considering the workforce needs associated with nuclear generation facilities and new skills required to operate a modernized, technology-enabled power grid. If the Duke Energy Registrants are unable to successfully attract and retain an appropriately qualified workforce, their results of operations, financial position and cash flows could be negatively affected.

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ITEM 1. BUSINESS ##TABLE_START ##TABLE_ENDDUKE ENERGY ##TABLE_START ##TABLE_ENDGeneral Duke Energy was incorporated on May 3, 2005, and is an energy company headquartered in Charlotte, North Carolina, subject to regulation by the FERC and other regulatory agencies listed below. Duke Energy operates in the U.S. primarily through its direct and indirect subsidiaries. Certain Duke Energy subsidiaries are also Subsidiary Registrants, including Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida, Duke Energy Ohio, Duke Energy Indiana and Piedmont. When discussing Duke Energys consolidated financial information, it necessarily includes the results of its separate Subsidiary Registrants, which along with Duke Energy, are collectively referred to as the Duke Energy Registrants. The Duke Energy Registrants electronically file reports with the SEC, including Annual Reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and amendments to such reports. The SEC maintains an internet site that contains reports, proxy and information statements and other information regarding issuers that file electronically with the SEC at sec.gov. Additionally, information about the Duke Energy Registrants, including reports filed with the SEC, is available through Duke Energys website at duke-energy.com. Such reports are accessible at no charge and are made available as soon as reasonably practicable after such material is filed with or furnished to the SEC. Business Segments Duke Energy's segment structure includes two reportable business segments: Electric Utilities and Infrastructure (EUI) and Gas Utilities and Infrastructure (GUI). The remainder of Duke Energys operations is presented as Other. Commercial Renewables is reported as discontinued operations and is no longer a reportable segment beginning in the fourth quarter of 2022. See Note 2 for further details. Duke Energy's chief operating decision-maker routinely reviews financial information about each of these business segments in deciding how to allocate resources and evaluate the performance of the business. For additional information on each of these business segments, including financial and geographic information, see Note 3 to the Consolidated Financial Statements, Business Segments. The following sections describe the business and operations of each of Duke Energys business segments, as well as Other. ELECTRIC UTILITIES AND INFRASTRUCTURE EUI conducts operations primarily through the regulated public utilities of Duke Energy Carolinas, Duke Energy Progress, Duke Energy Florida, Duke Energy Indiana and Duke Energy Ohio. EUI provides retail electric service through the generation, transmission, distribution and sale of electricity to approximately 8.2 million customers within the Southeast and Midwest regions of the U.S. The service territory is approximately 92,000 square miles across six states with a total estimated population of 26 million. The operations include electricity sold wholesale to municipalities, electric cooperative utilities and other load-serving entities. During 2021, Duke Energy executed an agreement providing for an investment by an affiliate of GIC in Duke Energy Indiana in exchange for a 19.9% minority interest issued by Duke Energy Indiana Holdco, LLC, the holding company for Duke Energy Indiana. The transaction was completed following two closings. Additionally, in November 2022, Duke Energy committed to a plan to sell the Commercial Renewables business segment, excluding the offshore wind contract for Carolina Long Bay, which was moved to EUI. See Note 2 to the Consolidated Financial Statements, Dispositions," for additional information. EUI is also a joint owner in certain electric transmission projects. EUI has a 50% ownership interest in DATC, a partnership with American Transmission Company, formed to design, build and operate transmission infrastructure. DATC owns 72% of the transmission service rights to Path 15, an 84-mile transmission line in central California. EUI also has a 50% ownership interest in Pioneer, which builds, owns and operates electric transmission facilities in North America. The following map shows the service territory for EUI as of December 31, 2022. ##TABLE_START BUSINESS ##TABLE_ENDThe electric operations and investments in projects are subject to the rules and regulations of the FERC, the NRC, the NCUC, the PSCSC, the FPSC, the IURC, the PUCO and the KPSC. The following table represents the distribution of GWh billed sales by customer class for the year ended December 31, 2022. ##TABLE_START Duke Duke Duke Duke Duke Energy Energy Energy Energy Energy Carolinas Progress Florida Ohio Indiana Residential 33 % 26 % 47 % 38 % 30 % General service 33 % 22 % 34 % 38 % 27 % Industrial 23 % 16 % 8 % 22 % 28 % Total retail sales 89 % 64 % 89 % 98 % 85 %

Wholesale and other sales 11 % 36 % 11 % 2 % 15 % Total sales 100 % 100 % 100 % 100 % 100 % ##TABLE_ENDThe number of residential and general service customers within the EUI service territory is expected to increase over time. Sales growth is expected within the service territory but continues to be impacted by adoption of energy efficiencies and self-generation. Migration into EUIs service territories and continued remote work contributed to higher residential sales volumes in 2022 while higher data center usage contributed to growth in commercial sales volumes. This was partially offset by lower industrial sales volumes impacted by certain automotive customers experiencing supply chain constraints along with reduced volumes in the steel sector. The impact on customer's usage from these factors and other potential economic dynamics continues to be monitored. Over the longer time frame, it is still expected that the continued adoption of more efficient housing and appliances will have a negative impact on average usage per residential customer over time. Seasonality and the Impact of Weather Revenues and costs are influenced by seasonal weather patterns. Peak sales of electricity occur during the summer and winter months, which results in higher revenue and cash flows during these periods. By contrast, lower sales of electricity occur during the spring and fall, allowing for scheduled plant maintenance. Residential and general service customers are more impacted by weather than industrial customers. Estimated weather impacts are based on actual current period weather compared to normal weather conditions. Normal weather conditions are defined as the long-term average of actual historical weather conditions. The estimated impact of weather on earnings is based on the temperature variances from a normal condition and customers historic usage patterns. The methodology used to estimate the impact of weather does not consider all variables that may impact customer response to weather conditions such as humidity in the summer or wind chill in the winter. The precision of this estimate may also be impacted by applying long-term weather trends to shorter-term periods. ##TABLE_START BUSINESS ##TABLE_ENDHeating degree days measure the variation in weather based on the extent the average daily temperature falls below a base temperature. Cooling degree days measure the variation in weather based on the extent the average daily temperature rises above the base temperature. Each degree of temperature below the base temperature counts as one heating degree day and each degree of temperature above the base temperature counts as one cooling degree day. Competition Retail EUIs businesses operate as the sole supplier of electricity within their service territories, with the exception of Ohio, which has a competitive electricity supply market for generation service. EUI owns and operates facilities necessary to generate, transmit, distribute and sell electricity. Services are priced by state commission-approved rates designed to include the costs of providing these services and a reasonable return on invested capital. This regulatory policy is intended to provide safe and reliable electricity at fair prices. In Ohio, EUI conducts competitive auctions for electricity supply. The cost of energy purchased through these auctions is recovered from retail customers. EUI earns retail margin in Ohio on the transmission and distribution of electricity, but not on the cost of the underlying energy. Competition in the regulated electric distribution business is primarily from the development and deployment of alternative energy sources including on-site generation from industrial customers and distributed generation, such as private solar, at residential, general service and/or industrial customer sites. Wholesale Duke Energy competes with other utilities and merchant generators for bulk power sales, sales to municipalities and cooperatives and wholesale transactions under primarily cost-based contracts approved by FERC. The principal factors in competing for these sales are availability of capacity and power, reliability of service and price. Prices are influenced primarily by market conditions and fuel costs. Increased competition in the wholesale electric utility industry and the availability of transmission access could affect EUIs load forecasts, plans for power supply and wholesale energy sales and related revenues. Wholesale energy sales will be impacted by the extent to which additional generation is available to sell to the wholesale market and the ability of EUI to attract new customers and to retain existing customers. Energy Capacity and Resources EUI owns approximately 49,870 MW of generation capacity. For additional information on owned generation facilities, see Item 2, Properties. Energy and capacity are also supplied through contracts with other generators and purchased on the open market. Factors that could cause EUI to purchase power for its customers may include, but are not limited to, generating plant outages, extreme weather conditions, generation reliability, demand growth and price. EUI has interconnections and arrangements with its neighboring utilities to facilitate planning, emergency assistance, sale and purchase of capacity and energy and reliability of power supply. EUIs generation portfolio is a balanced mix of energy resources having different operating characteristics and fuel sources designed to provide energy at the lowest possible cost to meet its obligation to serve retail customers. All options, including owned generation resources and purchased power opportunities, are continually evaluated on a real-time basis to select and dispatch the lowest-cost resources available to meet system load requirements. Sources of Electricity EUI relies principally on natural gas, nuclear fuel and coal for its generation of electricity. The following table lists sources of electricity and fuel costs for the three years ended December 31, 2022. ##TABLE_START Cost of Delivered Fuel per Net Generation by Source Kilowatt-hour Generated (Cents) 2022 2021 2020 2022 2021 2020 Natural gas and fuel oil (a) 34.2 % 31.8 % 31.3 % 6.35 3.89 2.55 Nuclear (a) 26.6 % 29.8 % 29.6 % 0.58 0.58 0.58 Coal (a) 13.5 % 18.2 % 18.1 % 3.43 2.84 2.99 All fuels (cost based on weighted average) (a) 74.3 % 79.8 % 79.0 % 3.75 2.42 1.91 Hydroelectric and solar (b) 1.5 % 1.5 % 1.9 % Total generation 75.8 % 81.3 % 80.9 % Purchased power and net interchange 24.2 % 18.7 % 19.1 % Total sources of energy 100.0 % 100.0 % 100.0 % ##TABLE_END(a) Statistics related to all fuels reflect EUI's public utility ownership interest in jointly owned generation facilities. (b) Generating figures are net of output required to replenish pumped-storage facilities during off-peak periods. Natural Gas and Fuel Oil Natural gas and fuel oil supply, transportation and storage for EUIs generation fleet is purchased under standard industry agreements from various suppliers, including Piedmont. Natural gas supply agreements typically provide for a percentage of forecasted burns being procured over time, with varied expiration dates. Electric Utilities and Infrastructure believes it has access to an adequate supply of natural gas and fuel oil for the reasonably foreseeable future. ##TABLE_START BUSINESS ##TABLE_ENDEUI has certain dual-fuel generating facilities that can operate utilizing both natural gas and fuel oil. The cost of EUIs natural gas and fuel oil is fixed price or determined by published market prices as reported in certain industry publications, plus any transportation and freight costs. Duke Energy Carolinas, Duke Energy Progress, Duke Energy Florida and Duke Energy Indiana use derivative instruments to manage a portion of their exposure to price fluctuations for natural gas. Duke Energy Florida has temporarily agreed to not hedge natural gas prices, but retains an ability to propose hedging again in annual fuel docket filings. EUI has firm interstate and intrastate natural gas transportation agreements and storage agreements in place to support generation needed for load requirements. EUI may purchase additional shorter-term natural gas transportation and utilize natural gas interruptible transportation agreements to support generation needed for load requirements. The EUI natural gas plants are served by various supply zones and multiple pipelines. Nuclear The industrial processes for producing nuclear generating fuel generally involve the mining and milling of uranium ore to produce uranium concentrates and services to convert, enrich and fabricate fuel assemblies. EUI has contracted for uranium materials and services to fuel its nuclear reactors. Uranium concentrates, conversion services and enrichment services are primarily met through a diversified portfolio of long-term supply contracts. The contracts are diversified by supplier, country of origin and pricing. EUI staggers its contracting so that its portfolio of long-term contracts covers the majority of its fuel requirements in the near term and decreasing portions of its fuel requirements over time thereafter. Near-term requirements not met by long-term supply contracts have been and are expected to be fulfilled with spot market purchases. Due to the technical complexities of changing suppliers of fuel fabrication services, EUI generally source these services to a single domestic supplier on a plant-by-plant basis using multiyear contracts. EUI has entered into fuel contracts that cover 100% of its uranium concentrates through at least 2024, 100% of its conversion services through at least 2026, 100% of its enrichment services through at least 2026, and 100% of its fabrication services requirements for these plants through at least 2027. For future requirements not already covered under long-term contracts, EUI believes it will be able to renew contracts as they expire or enter into similar contractual arrangements with other suppliers of nuclear fuel materials and services. Coal EUI meets its coal demand through a portfolio of long-term purchase contracts and short-term spot market purchase agreements. Large amounts of coal are purchased under long-term contracts with mining operators who mine both underground and at the surface. EUI uses spot market purchases to meet coal requirements not met by long-term contracts. Expiration dates for its long-term contracts, which may have various price adjustment provisions and market reopeners, range from 2023 to 2027 for Duke Energy Carolinas and Duke Energy Indiana, 2023 to 2024 for Duke Energy Progress and 2023 to 2025 for Duke

Energy Florida and Duke Energy Ohio. EUI expects to renew these contracts or enter into similar contracts with other suppliers as existing contracts expire, though prices will fluctuate over time as coal markets change. EUI has an adequate supply of coal under contract to meet its risk management guidelines regarding projected future consumption. As a result of volatility in natural gas prices and the associated impacts on coal-fired dispatch within the generation fleet, coal inventories will continue to fluctuate. EUI continues to actively manage its portfolio and has worked with suppliers to obtain increased flexibility in its coal contracts. Coal purchased for the Carolinas is primarily produced from mines in Central Appalachia, Northern Appalachia and the Illinois Basin. Coal purchased for Florida is primarily produced from mines in the Illinois Basin. Coal purchased for Kentucky is produced from mines along the Ohio River in Illinois, Ohio, West Virginia and Pennsylvania. Coal purchased for Indiana is primarily produced in Indiana and Illinois. There are adequate domestic coal reserves to serve EUI's coal generation needs through end of life. The current average sulfur content of coal purchased by Electric Utilities and Infrastructure is between 0.5% and 3.5% for Duke Energy Carolinas and Duke Energy Progress, and between 0.5% and 4% for Duke Energy Florida, Duke Energy Ohio and Duke Energy Indiana. EUI's environmental controls, in combination with the use of sulfur dioxide (SO 2) emission allowances, enable EUI to satisfy current SO 2 emission limitations for its existing facilities. Purchased Power EUI purchases a portion of its capacity and system requirements through purchase obligations, leases and purchase capacity contracts. EUI believes it can obtain adequate purchased power capacity to meet future system load needs. However, during periods of high demand, the price and availability of purchased power may be significantly affected. The following table summarizes purchased power for the previous three years: ##TABLE_START 2022 2021 2020 Purchase obligations and leases (in millions of MWh) (a) 41.2 36.0 32.7 Purchase capacity under contract (in MW) (b) 4,028 4,259 4,716 ##TABLE_END(a) Represents approximately 16% of total system requirements for 2022, 14% for 2021 and 13% for 2020. (b) For 2022, 2021 and 2020, these agreements include approximately 412 MW of firm capacity under contract by Duke Energy Florida with QFs. Inventory EUI must maintain an adequate stock of fuel and materials and supplies in order to ensure continuous operation of generating facilities and reliable delivery to customers. As of December 31, 2022, the inventory balance for EUI was approximately $3.4 billion. For additional information on inventory, see Note 1 to the Consolidated Financial Statements, Summary of Significant Accounting Policies. ##TABLE_START BUSINESS ##TABLE_ENDAsh Basin Management During 2015, EPA issued regulations related to the management of CCR from power plants. These regulations classify CCR as nonhazardous waste under the Resource Conservation and Recovery Act (RCRA) and apply to electric generating sites with new and existing landfills and new and existing surface impoundments and establish requirements regarding landfill design, structural integrity design and assessment criteria for surface impoundments, groundwater monitoring, protection and remedial procedures and other operational and reporting procedures for the disposal and management of CCR. In addition to the federal regulations, CCR landfills and surface impoundments (ash basins or impoundments) will continue to be regulated by existing state laws, regulations and permits, such as the North Carolina Coal Ash Management Act of 2014 (Coal Ash Act). EUI has and will periodically submit to applicable authorities required site-specific coal ash impoundment remediation or closure plans. Closure plans must be approved and all associated permits issued before any work can begin. Closure activities have begun in all of Duke Energy's jurisdictions. Excavation began in 2015 at the four sites specified as high priority by the Coal Ash Act and at the W.S. Lee Steam Station site in South Carolina in connection with other legal requirements. Excavation at these sites involves movement of CCR materials to appropriate engineered off-site or on-site lined landfills or for reuse in an approved beneficial application. Duke Energy has completed excavation of coal ash at the four high-priority North Carolina sites. At other sites where CCR management is required, planning and closure methods have been studied and factored into the estimated retirement and management costs, and closure activities have commenced. The EPA CCR rule and the Coal Ash Act leave the decision on cost recovery determinations related to closure of coal ash surface impoundments to the normal ratemaking processes before utility regulatory commissions. Duke Energy's electric utilities have included compliance costs associated with federal and state requirements in their respective rate proceedings. During 2017, Duke Energy Carolinas' and Duke Energy Progress wholesale contracts were amended to include the recovery of expenditures related to AROs for the closure of coal ash basins. The amended contracts have retail disallowance parity or provisions limiting challenges to CCR cost recovery actions at FERC. FERC approved the amended wholesale rate schedules in 2017. For additional information on the ash basins and recovery, see Item 7, "Other Matters" and Notes 4, 5 and 10 to the Consolidated Financial Statements, "Regulatory Matters," "Commitments and Contingencies" and "Asset Retirement Obligations," respectively. Nuclear Matters Duke Energy owns, wholly or partially, 11 operating nuclear reactors located at six operating stations. The Crystal River Unit 3 permanently ceased operation in February 2013. Nuclear insurance includes: nuclear liability coverage; property damage coverage; nuclear accident decontamination and premature decommissioning coverage; and accidental outage coverage for losses in the event of a major accidental outage. Joint owners reimburse Duke Energy for certain expenses associated with nuclear insurance in accordance with joint owner agreements. The Price-Anderson Act requires plant owners to provide for public nuclear liability claims resulting from nuclear incidents to the maximum total financial protection liability, which is approximately $13.7 billion. For additional information on nuclear insurance, see Note 5 to the Consolidated Financial Statements, Commitments and Contingencies. Duke Energy has a significant future financial commitment to dispose of spent nuclear fuel and decommission and decontaminate each plant safely. The NCUC, PSCSC and FPSC require Duke Energy to update their cost estimates for decommissioning their nuclear plants every five years. The following table summarizes the fair value of NDTF investments and the most recent site-specific nuclear decommissioning cost studies. Decommissioning costs are stated in 2018 or 2019 dollars, depending on the year of the cost study, and include costs to decommission plant components not subject to radioactive contamination. ##TABLE_START NDTF (a) Decommissioning (in millions) December 31, 2022 December 31, 2021 Costs (a) Year of Cost Study Duke Energy $ 8,637 $ 10,401 $ 9,105 2018 or 2019 Duke Energy Carolinas (b)(c) 4,783 5,759 4,365 2018 Duke Energy Progress (d) 3,430 4,089 4,181 2019 Duke Energy Florida (e) 424 553 559 N/A ##TABLE_END(a) Amounts for Progress Energy equal the sum of Duke Energy Progress and Duke Energy Florida. (b) Decommissioning cost for Duke Energy Carolinas reflects its ownership interest in jointly owned reactors. Other joint owners are responsible for decommissioning costs related to their interest in the reactors. (c) Duke Energy Carolinas' site-specific nuclear decommissioning cost study completed in 2018 was filed with the NCUC and PSCSC in 2019. A new funding study was also completed and filed with the NCUC and PSCSC in 2019. (d) Duke Energy Progress' site-specific nuclear decommissioning cost study completed in 2019 was filed with the NCUC and PSCSC in March 2020. Duke Energy Progress also completed a funding study, which was filed with the NCUC and PSCSC in July 2020. In October 2021, Duke Energy Progress filed the 2019 nuclear decommissioning cost study with the FERC, as well as a revised date schedule for decommissioning expense to be collected from wholesale customers. The FERC accepted the filing, as filed on December 9, 2021. (e) During 2019, Duke Energy Florida reached an agreement to transfer decommissioning work for Crystal River Unit 3 to a third party and decommissioning costs are based on the agreement with this third party rather than a cost study. Regulatory approval was received from the NRC and the FPSC in April 2020 and August 2020, respectively. See Note 4 to the Consolidated Financial Statements, "Regulatory Matters, for more information. The NCUC, PSCSC, FPSC and FERC have allowed EUI to recover estimated decommissioning costs through retail and wholesale rates over the expected remaining service periods of their nuclear stations. EUI believes the decommissioning costs being recovered through rates, when coupled with the existing fund balances and expected fund earnings, will be sufficient to provide for the cost of future decommissioning. For additional information, see Note 10 to the Consolidated Financial Statements, Asset Retirement Obligations. ##TABLE_START BUSINESS ##TABLE_ENDThe Nuclear Waste Policy Act of 1982 (as amended) provides the framework for development by the federal government of interim storage and permanent disposal facilities for high-level radioactive waste materials. The government has not yet developed a storage facility or disposal capacity, so EUI will continue to store spent fuel on its reactor sites. Under federal law, the DOE is responsible for the selection and construction of a facility for the permanent disposal of spent nuclear fuel and high-level radioactive waste. The DOE terminated the project to license and develop a geologic repository at Yucca Mountain, Nevada in 2010, and is currently taking no action to fulfill its responsibilities to dispose of spent fuel. Until the DOE begins to accept the spent nuclear fuel, Duke Energy Carolinas, Duke Energy Progress and

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Duke Energy Florida will continue to safely manage their spent nuclear fuel. Under current regulatory guidelines, Harris has sufficient storage capacity in its spent fuel pools through the expiration of its renewed operating license. With certain modifications and approvals by the NRC to expand the on-site dry cask storage facilities, spent nuclear fuel dry storage facilities will be sufficient to provide storage space of spent fuel through the expiration of the operating licenses, including any license renewals, for Brunswick, Catawba, McGuire, Oconee and Robinson. Crystal River Unit 3 ceased operation in 2013 and was placed in a SAFSTOR condition in January 2018. As of January 2018, all spent fuel at Crystal River Unit 3 has been transferred from the spent fuel pool to dry storage at an on-site independent spent fuel storage installation. During 2020, the NRC and the FPSC approved an agreement to transfer ownership of spent fuel for Crystal River Unit 3 to a third party. See Note 4 to the Consolidated Financial Statements, "Regulatory Matters, for more information. The nuclear power industry faces uncertainties with respect to the cost and long-term availability of disposal sites for spent nuclear fuel and other radioactive waste, compliance with changing regulatory requirements, capital outlays for modifications and new plant construction. EUI is subject to the jurisdiction of the NRC for the design, construction and operation of its nuclear generating facilities. The following table includes the current year of expiration of nuclear operating licenses for nuclear stations in operation. In June 2021, Duke Energy Carolinas filed a subsequent license renewal application for the Oconee Nuclear Station (ONS) with the U.S. Nuclear Regulatory Commission to renew ONS's operating license for an additional 20 years. Duke Energy has announced its intention to seek 20-year operating license renewals for each of the reactors it operates in Duke Energy Carolinas and Duke Energy Progress. See Note 4 to the Consolidated Financial Statements, "Regulatory Matters, for additional information. ##TABLE_START Unit Year of Expiration Duke Energy Carolinas Catawba Units 1 and 2 2043 McGuire Unit 1 2041 McGuire Unit 2 2043 Oconee Units 1 and 2 2033 Oconee Unit 3 2034 Duke Energy Progress Brunswick Unit 1 2036 Brunswick Unit 2 2034 Harris 2046 Robinson 2030 ##TABLE_ENDThe NRC has acknowledged permanent cessation of operation and permanent removal of fuel from the reactor vessel at Crystal River Unit 3. Therefore, the license no longer authorizes operation of the reactor. For additional information on nuclear decommissioning activity, see Notes 4 and 10 to the Consolidated Financial Statements, "Regulatory Matters" and "Asset Retirement Obligations," respectively. Regulation State The state electric utility commissions approve rates for Duke Energy's retail electric service within their respective states. The state electric utility commissions, to varying degrees, have authority over the construction and operation of EUIs generating facilities. CPCNs issued by the state electric utility commissions, as applicable, authorize EUI to construct and operate its electric facilities and to sell electricity to retail and wholesale customers. Prior approval from the relevant state electric utility commission is required for the entities within EUI to issue securities. The underlying concept of utility ratemaking is to set rates at a level that allows the utility to collect revenues equal to its cost of providing service plus earn a reasonable rate of return on its invested capital, including equity. In addition to rates approved in base rate cases, each of the state electric utility commissions allow recovery of certain costs through various cost recovery clauses to the extent the respective commission determines in periodic hearings that such costs, including any past over or under-recovered costs, are prudent. Fuel, fuel-related costs and certain purchased power costs are eligible for recovery by EUI. EUI uses coal, hydroelectric, natural gas, oil, renewable generation and nuclear fuel to generate electricity, thereby maintaining a diverse fuel mix that helps mitigate the impact of cost increases in any one fuel. Due to the associated regulatory treatment and the method allowed for recovery, changes in fuel costs from year to year have no material impact on operating results of EUI, unless a commission finds a portion of such costs to have been imprudent. However, delays between the expenditure for fuel costs and recovery from customers can adversely impact the timing of cash flows of EUI. ##TABLE_START BUSINESS ##TABLE_ENDThe table below reflects significant electric rate case applications approved and effective in the past three years and applications currently pending approval. ##TABLE_START Regulatory Body Annual Increase (Decrease) (in millions) Return on Equity Equity Component of Capital Structure Effective Date Approved Rate Cases: Duke Energy Progress 2022 South Carolina Rate Case PSCSC $ 52 9.6 % 52.43 % 4/1/2023 Duke Energy Ohio 2021 Ohio Electric Rate Case PUCO 23 9.5 % 50.5 % 1/3/2023 Duke Energy Progress 2019 North Carolina Rate Case NCUC 178 9.6 % 52 % 6/1/2021 Duke Energy Carolinas 2019 North Carolina Rate Case NCUC 33 9.6 % 52 % 6/1/2021 Duke Energy Indiana 2019 Indiana Rate Case (a) IURC 146 9.7 % 54 % 7/30/2020 Duke Energy Kentucky 2019 Kentucky Electric Rate Case KPSC 24 9.25 % 48.23 % 5/1/2020 Pending Rate Cases: Duke Energy Carolinas 2023 North Carolina Rate Case (b) NCUC $ 823 10.4 % 53 % 1/1/2024 Duke Energy Kentucky 2022 Kentucky Electric Rate Case KPSC 75 10.35 % 52.5 % 7/15/2023 Duke Energy Progress 2022 North Carolina Rate Case (c) NCUC 615 10.4 % 53 % 10/1/2023 ##TABLE_END(a) Step 1 rates are approximately 75% of the total and became effective July 30, 2020. Step 2 rates are approximately 25% of the total rate case increase. They were approved on July 28, 2021, and implemented in August 2021. (b) Year 1 rates are approximately 61% of the total. Year 2 rates are approximately 21% of the total rate case increase. Year 3 rates are approximately 18% of the total rate increase. (c) Year 1 rates are approximately 53% of the total. Year 2 rates are approximately 25% of the total rate case increase. Year 3 rates are approximately 22% of the total rate increase. Implementation of interim rates is planned for June 1, 2023. Additionally, in January 2021, Duke Energy Florida filed a settlement agreement with the FPSC that will allow annual increases to its base rates, an agreed upon return on equity (ROE) and includes a base rate stay-out provision through 2024, among other provisions. The FPSC approved the 2021 Settlement on May 4, 2021, issuing an order on June 4, 2021. Revised customer rates became effective January 1, 2022, with subsequent base rate increases effective January 1, 2023, and January 1, 2024. For more information on rate matters and other regulatory proceedings, see Note 4 to the

Consolidated Financial Statements, Regulatory Matters. Federal The FERC approves EUIs cost-based rates for electric sales to certain power and transmission wholesale customers. Regulations of FERC and the state electric utility commissions govern access to regulated electric and other data by nonregulated entities and services provided between regulated and nonregulated energy affiliates. These regulations affect the activities of nonregulated affiliates with EUI. RTOs PJM and MISO are the ISOs and FERC-approved RTOs for the regions in which Duke Energy Ohio and Duke Energy Indiana operate. PJM and MISO operate energy, capacity and other markets, and control the day-to-day operations of bulk power systems through central dispatch. Duke Energy Ohio is a member of PJM and Duke Energy Indiana is a member of MISO. Transmission owners in these RTOs have turned over control of their transmission facilities and their transmission systems are currently under the dispatch control of the RTOs. Transmission service is provided on a regionwide, open-access basis using the transmission facilities of the RTO members at rates based on the costs of transmission service. Environmental EUI is subject to the jurisdiction of the EPA and state and local environmental agencies. For a discussion of environmental regulation, see Environmental Matters in this section. See the Other Matters section of Item 7 Management's Discussion and Analysis for a discussion about potential Global Climate Change legislation and other EPA regulations under development and the potential impacts such legislation and regulation could have on Duke Energys operations. GAS UTILITIES AND INFRASTRUCTURE GUI conducts natural gas operations primarily through the regulated public utilities of Piedmont, Duke Energy Ohio and Duke Energy Kentucky. The natural gas operations are subject to the rules and regulations of the NCUC, PSCSC, PUCO, KPSC, TPUC, PHMSA and the FERC. GUI serves residential, commercial, industrial and power generation natural gas customers, including customers served by municipalities who are wholesale customers. GUI has over 1.6 million total customers, including 1.1 million customers located in North Carolina, South Carolina and Tennessee, and an additional 550,000 customers located within southwestern Ohio and northern Kentucky. In the Carolinas, Ohio and Kentucky, the service areas are comprised of numerous cities, towns and communities. In Tennessee, the service area is the metropolitan area of Nashville. The following map shows the service territory and investments in operating pipelines for GUI as of December 31, 2022. ##TABLE_START BUSINESS ##TABLE_ENDThe number of residential, commercial and industrial customers within the GUI service territory is expected to increase over time. Average usage per residential customer is expected to remain flat or decline for the foreseeable future; however, decoupled rates in North Carolina and various rate design mechanisms in other jurisdictions partially mitigate the impact of the declining usage per customer on overall profitability. GUI also has investments in various pipeline transmission projects, renewable natural gas projects and natural gas storage facilities. Natural Gas for Retail Distribution GUI is responsible for the distribution of natural gas to retail customers in its North Carolina, South Carolina, Tennessee, Ohio and Kentucky service territories. GUIs natural gas procurement strategy is to contract primarily with major and independent producers and marketers for natural gas supply. It also purchases a diverse portfolio of transportation and storage service from interstate pipelines. This strategy allows GUI to assure reliable natural gas supply and transportation for its firm customers during peak winter conditions. When firm pipeline services or contracted natural gas supplies are temporarily not needed due to market demand fluctuations, GUI may release these services and supplies in the secondary market under FERC-approved capacity release provisions or make wholesale secondary market sales. In 2022, firm supply purchase commitment agreements provided 100% of the natural gas supply for both Piedmont and Duke Energy Ohio. Approximately 90% of forecasted demand was under contract prior to the winter heating season, with firm daily spot purchases making up the balance. ##TABLE_START BUSINESS ##TABLE_ENDImpact of Weather GUI revenues are generally protected from the impact of weather fluctuations due to the regulatory mechanisms that are available in most service territories. In North Carolina, margin decoupling provides protection from both weather and other usage variations like conservation for residential and small and medium general service customers. Margin decoupling provides a set margin per customer independent of actual usage. In South Carolina, Tennessee and Kentucky, weather normalization adjusts revenues either up or down depending on how much warmer or colder than normal a given month has been. Weather normalization adjustments occur from November through March in South Carolina, from October through April in Tennessee and from November through April in Kentucky. Duke Energy Ohio collects most of its non-fuel revenue through a fixed monthly charge that is not impacted by usage fluctuations that result from weather changes or conservation. Competition GUIs businesses operate as the sole provider of natural gas service within their retail service territories. GUI owns and operates facilities necessary to transport and distribute natural gas. GUI earns retail margin on the transmission and distribution of natural gas and not on the cost of the underlying commodity. Services are priced by state commission-approved rates designed to include the costs of providing these services and a reasonable return on invested capital. This regulatory policy is intended to provide safe and reliable natural gas service at fair prices. In residential, commercial and industrial customer markets, natural gas distribution operations compete with other companies that supply energy, primarily electric companies, propane and fuel oil dealers, renewable energy providers and coal companies in relation to sources of energy for electric power plants, as well as nuclear energy. A significant competitive factor is price. GUI's primary product competition is with electricity for heating, water heating and cooking. Increases in the price of natural gas or decreases in the price of other energy sources could negatively impact competitive position by decreasing the price benefits of natural gas to the consumer. In the case of industrial customers, such as manufacturing plants, adverse economic or market conditions, including higher natural gas costs, could cause these customers to suspend business operations or to use alternative sources of energy in favor of energy sources with lower per-unit costs. Higher natural gas costs or decreases in the price of other energy sources may allow competition from alternative energy sources for applications that have traditionally used natural gas, encouraging some customers to move away from natural gas-fired equipment to equipment fueled by other energy sources. Competition between natural gas and other forms of energy is also based on efficiency, performance, reliability, safety and other non-price factors. Technological improvements in other energy sources and events that impair the public perception of the non-price attributes of natural gas could erode our competitive advantage. These factors in turn could decrease the demand for natural gas, impair our ability to attract new customers and cause existing customers to switch to other forms of energy or to bypass our systems in favor of alternative competitive sources. This could result in slow or no customer growth and could cause customers to reduce or cease using our product, thereby reducing our ability to make capital expenditures and otherwise grow our business, adversely affecting our earnings. Natural Gas Investments Duke Energy, through its GUI segment, has a 7.5% equity ownership interest in Sabal Trail. Sabal Trail is a joint venture that owns the Sabal Trail Natural Gas Pipeline (Sabal Trail pipeline) to transport natural gas to Florida, regulated by FERC. The Sabal Trail Phase I mainline was placed into service in July 2017 and traverses Alabama, Georgia and Florida. The remaining lateral line to the Duke Energy Florida's Citrus County CC was placed into service in March 2018. Phase II of Sabal Trail went into service in May 2020, adding approximately 200,000 Dth of capacity to the Sabal Trail pipeline. Duke Energy, through its GUI segment, has a 47% equity ownership interest in ACP, which planned to build the ACP pipeline, an approximately 600-mile interstate natural gas pipeline. The ACP pipeline was intended to transport diverse natural gas supplies into southeastern markets and would be regulated by FERC. Dominion Energy owns 53% of ACP and was contracted to construct and operate the ACP pipeline upon completion. On July 5, 2020, Dominion announced a sale of substantially all of its natural gas transmission and storage segment assets, which were critical to the ACP pipeline. Further, permitting delays and legal challenges had materially affected the timing and cost of the pipeline. As a result, Duke Energy determined that they would no longer invest in the construction of the ACP pipeline. Duke Energy, also through its GUI segment, has investments in various renewable natural gas joint ventures. GUI has a 21.49% equity ownership interest in Cardinal, an intrastate pipeline located in North Carolina regulated by the NCUC, a 45% equity ownership in Pine Needle, an interstate liquefied natural gas storage facility located in North Carolina and a 50% equity ownership interest in Hardy Storage, an underground interstate natural gas storage facility located in Hardy and Hampshire counties in West Virginia. Pine Needle and Hardy Storage are regulated by FERC. KO Transmission Company (KO Transmission), a wholly owned subsidiary of Duke Energy Ohio, is an interstate pipeline company engaged in the business of transporting natural gas and is subject to the rules and regulations of FERC. KO Transmission's 90-mile pipeline supplies natural gas to Duke Energy Ohio and interconnects with the Columbia Gulf Transmission pipeline and Tennessee Gas Pipeline. An approximately 70-mile portion of KO Transmission's pipeline facilities is co-owned by Columbia Gas Transmission, LLC. KO Transmission sold all of its pipeline facilities and related real property to Columbia Gas Transmission, LLC on February 1, 2023, for approximately book value. See Notes 4, 13 and 18 to the Consolidated Financial Statements, "Regulatory Matters," "Investments in Unconsolidated Affiliates" and "Variable Interest Entities," respectively, for further information on Duke Energy's and GUI's natural gas investments. Inventory GUI must maintain adequate natural gas inventory in order to provide reliable delivery to customers. As of December 31, 2022, the inventory balance for GUI was $185 million. For more information on inventory, see Note 1 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies." ##TABLE_START BUSINESS ##TABLE_ENDRegulation State The state gas utility commissions approve rates for Duke Energy's retail natural gas service within their respective states. The state gas utility commissions, to varying degrees, have authority over the construction and operation of GUIs natural gas distribution facilities. CPCNs issued by the state gas utility commissions or other government agencies, as applicable, authorize GUI to construct and operate its natural gas distribution facilities and to sell natural gas to retail and wholesale customers. Prior approval from the relevant state gas utility commission is required for GUI to issue securities. The underlying concept of utility ratemaking is to set rates at a level that allows the utility to collect revenues equal to its cost of providing service plus a reasonable rate of return on its invested capital, including equity. In addition to amounts collected from customers through approved base rates, each of the state gas utility commissions allow recovery of certain costs through various cost recovery clauses to the extent the respective commission determines in periodic hearings that such costs, including any past over- or under-recovered costs, are prudent. Natural gas costs are eligible for recovery by GUI. Due to the associated regulatory treatment and the method allowed for recovery, changes in natural gas costs from year to year have no material impact on operating results of GUI, unless a commission finds a portion of such costs to have been imprudent. However, delays between the expenditure for natural gas and recovery from customers can adversely impact the timing of cash flows of GUI. The following table summarizes certain components underlying recently approved and effective base rates or rate stabilization filings in the last three years and applications currently pending approval. ##TABLE_START Annual Increase (Decrease) (in millions) Return on Equity Equity Component of Capital Structure Effective Date Approved Rate Cases: Piedmont 2020 Tennessee Natural Gas Base Rate Case $ 16 9.8 % 50.5 % January 2021 Piedmont 2021 North Carolina Natural Gas Base Rate Case 67 9.6 % 51.6 % November 2021 Piedmont 2021 South Carolina Rate Stabilization Adjustment Filing 7 9.8 % 52.2 % November 2021 Duke Energy Kentucky 2021 Natural Gas Base Rate Case (a) 9 9.38 % 51.3 % January 2022 Piedmont 2022 South Carolina Natural Gas Base Rate Case (b) 2 9.3 % 52.2 % November 2022 Pending Rate Cases: Duke Energy Ohio 2022 Natural Gas Base Rate Case 49 10.3 % 52.3 % April 2023 ##TABLE_END(a) An ROE of 9.375% for natural gas base rates and 9.3% for natural gas riders was approved. (b)

Under the rate stabilization adjustment (RSA) mechanism, Piedmont resets rates in South Carolina based on updated costs and revenues on an annual basis. The SC RSA filing for 2022 did not reset the rates since Piedmont filed a General Rate Case in 2022. GUI has an IMR mechanism in North Carolina designed to separately track and recover certain costs associated with capital investments incurred to comply with federal pipeline safety and integrity programs. Piedmont has withdrawn from the Tennessee IMR mechanism subsequent to the authorization of the Tennessee Annual Review Mechanism effective January 2022. The following table summarizes information related to the recently approved IMR filing. ##TABLE_START Cumulative Annual Effective (in millions) Investment Revenues Date Piedmont 2022 IMR Filing North Carolina $ 213 $ 20 December 2022 ##TABLE_ENDIn Ohio, GUI has a Capital Expenditure Program Rider (CEP Rider) designed to recover costs between rate cases on PUCO approved capital expenditures. Duke Energy Ohio submits a filing each year for incremental investments to increase the revenue requirement up to the cap of approximately $7 million. The cumulative investment under the CEP Rider is $359 million with total annual revenue requirement of $70 million. For more information on rate matters and other regulatory proceedings, see Note 4 to the Consolidated Financial Statements, Regulatory Matters. Federal GUI is subject to various federal regulations, including regulations that are particular to the natural gas industry. These federal regulations include but are not limited to the following: Regulations of the FERC affect the certification and siting of new interstate natural gas pipeline projects, the purchase and sale of, the prices paid for, and the terms and conditions of service for the interstate transportation and storage of natural gas. Regulations of the PHMSA affect the design, construction, operation, maintenance, integrity, safety and security of natural gas distribution and transmission systems. Regulations of the EPA relate to the environment including proposed air emissions regulations that would expand to include emissions of methane. ##TABLE_START BUSINESS ##TABLE_ENDRegulations of the FERC and the state gas utility commissions govern access to regulated natural gas and other data by nonregulated entities and services provided between regulated and nonregulated energy affiliates. These regulations affect the activities of nonregulated affiliates with Gas Utilities and Infrastructure. Environmental GUI is subject to the jurisdiction of the EPA and state and local environmental agencies. For a discussion of environmental regulation, see Environmental Matters in this section. See Other Matters section of Item 7 Management's Discussion and Analysis for a discussion about potential Global Climate Change legislation and other EPA regulations under development and the potential impacts such legislation and regulation could have on Duke Energys operations. OTHER The remainder of Duke Energys operations is presented as Other. While it is not a business segment, Other primarily includes interest expense on holding company debt, unallocated corporate costs, amounts related to certain companywide initiatives and contributions made to the Duke Energy Foundation. Other also includes Bison and an investment in NMC. The Duke Energy Foundation is a nonprofit organization funded by Duke Energy shareholders that makes charitable contributions to selected nonprofits and government subdivisions. Bison, a wholly owned subsidiary of Duke Energy, is a captive insurance company with the principal activity of providing Duke Energy subsidiaries with indemnification for financial losses primarily related to property, workers compensation and general liability. Duke Energy owns a 17.5% equity interest in NMC. The joint venture company has production facilities in Jubail, Saudi Arabia, where it manufactures certain petrochemicals and plastics. The company annually produces approximately 1 million metric tons each of MTBE and methanol and has the capacity to produce 50,000 metric tons of polyacetal. The main feedstocks to produce these products are natural gas and butane. Duke Energy records the investment activity of NMC using the equity method of accounting and retains 25% of NMC's board of directors' representation and voting rights. Human Capital Management Governance Our employees are critical to the success of our company. Our Human Resources organization is responsible for our human capital management strategy, which includes recruiting and hiring, onboarding and training, diversity and inclusion, workforce planning, talent and succession planning, performance management and employee development. Key areas of focus include fostering a high-performance and inclusive culture built on strong leadership and highly engaged and diverse employees, building a pipeline of skilled workers and ensuring knowledge transfer as employees retire. Our Board of Directors provides oversight on certain human capital management matters, primarily through the Compensation and People Development Committee, which is responsible for reviewing strategies and policies related to human capital management, including with respect to matters such as diversity and inclusion, employee engagement and talent development. Employees On December 31, 2022, Duke Energy had a total of 27,859 full-time, part-time and temporary employees, the majority of which were full-time employees. The total includes 5,081 employees who are represented by labor unions under various collective bargaining agreements that generally cover wages, benefits, working practices, and other terms and conditions of employment. Compensation The company seeks to attract and retain an appropriately qualified workforce and leverages Duke Energys leadership imperatives to foster a culture focused on customers, innovation, and highly engaged employees. Our compensation program is market driven and designed to link pay to performance with the goal of attracting and retaining talented employees, rewarding individual performance, and encouraging long-term commitment to our business. Our market competitive pay program includes short-term and long-term variable pay components that help to align the interests of Duke Energy to our customers and shareholders. In addition to competitive base pay, we provide eligible employees with compensation and benefits under a variety of plans and programs, including health care benefits, retirement savings, pension, health savings and flexible spending accounts, wellness, family leaves, employee assistance, as well as other benefits including a charitable matching program. The company is committed to providing market competitive, fair, and equitable compensation and regularly conducts internal pay equity reviews, and benchmarking against peer companies to ensure our pay is competitive. Diversity and

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Inclusion Duke Energy is committed to continuing to build a diverse workforce that reflects the communities we serve while strengthening a culture of inclusion where employees and customers feel respected and valued. Our Enterprise Diversity and Inclusion Council, chaired by our Chief Operating Officer in 2022, monitors the effectiveness and execution of our diversity and inclusion strategy and programs. Employee-led councils are also embedded across the company in our business units and focus on the specific diversity and inclusion needs of the business and help drive inclusion deeper into the employee experience. Leaders and individual contributors also have the opportunity to participate in voluntary diversity and inclusion training programs and facilitated conversations on insightful topics offered to further our commitment to building and enabling an inclusive work environment. Our aspirational goals include achieving workforce representation of at least 25% female and 20% racial and ethnic diversity. We continue to strive toward reaching these aspirational goals and as of December 31, 2022, our workforce consisted of approximately 23.9% female and 20.4% racial and ethnic diversity. ##TABLE_START BUSINESS ##TABLE_ENDThe company also has 10 Employee Resource Groups (ERGs), with 37 chapters and more than 6,500 employees participating. ERGs are networks of employees formed around a common dimension of diversity whose goals and objectives align with the company's goals and objectives. These groups focus on employee professional development and networking, community outreach, cultural awareness, recruiting and retention. They also serve as a resource to the company for advocacy and community outreach and improving customer service through innovation. ERG-sponsored forums include networking events, mentoring, scholarship banquets for aspiring college students, and workshops on topics such as time management, stress reduction, career planning and work-life balance. Our ERGs are open to all employees. Among other efforts, the company has developed partnerships with community organizations, community colleges and historically Black colleges and universities to support our strategy of building a diverse and highly skilled talent pipeline. Operational Excellence The foundation for our growth and success is our continued focus on operational excellence, the leading indicator of which is safety. As such, the safety of our workforce remains our top priority. The company closely monitors the total incident case rate (TICR), which is a metric based on strict OSHA definitions that measures the number of occupational injuries and illnesses per 100 employees. This objective emphasizes our focus on achieving an event-free and injury-free workplace. As an indication of our commitment to safety, we include safety metrics in both the short-term and long-term incentive plans based on the TICR for employees. Our employees delivered strong safety results in 2022, consistent with our industry-leading performance levels from 2017 through 2021. ##TABLE_START BUSINESS ##TABLE_ENDInformation about Our Executive Officers The following table sets forth the individuals who currently serve as executive officers. Executive officers serve until their successors are duly elected or appointed. ##TABLE_START Name Age (a) Current and Recent Positions Held Lynn J. Good 63 Chair, President and Chief Executive Officer. Ms. Good has served as Chair, President and Chief Executive Officer of Duke Energy since January 1, 2016, and was Vice Chairman, President and Chief Executive Officer of Duke Energy from July 2013 through December 2015. Prior to that, she served as Executive Vice President and Chief Financial Officer since 2009. Brian D. Savoy 47 Executive Vice President and Chief Financial Officer. Mr. Savoy assumed the position of Executive Vice President and Chief Financial Officer in September 2022. Prior to that, he held the position of Executive Vice President, Chief Strategy and Commercial Officer from May 2021 through August 2022; Senior Vice President, Chief Transformation and Administrative Officer from October 2019 through April 2021; Senior Vice President, Business Transformation and Technology from May 2016 through September 2019; Senior Vice President, Controller and Chief Accounting Officer from September 2013 to May 2016; Director, Forecasting and Analysis from 2009 to September 2013; and Vice President and Controller of the Commercial Power segment from 2006 to 2009. Kodwo Ghartey-Tagoe 59 Executive Vice President, Chief Legal Officer and Corporate Secretary . Mr. Ghartey-Tagoe assumed the position of Executive Vice President, Chief Legal Officer and Corporate Secretary in May 2020. He was appointed Executive Vice President and Chief Legal Officer in October 2019 after serving as President, South Carolina since 2017. Mr. Ghartey-Tagoe joined Duke Energy in 2002, and has held numerous management positions in Duke Energys Legal Department, including Duke Energy's Senior Vice President of State and Federal Regulatory Legal Support. T. Preston Gillespie 60 Executive Vice President, Chief Generation Officer and Enterprise Operational Excellence. Mr. Gillespie assumed the position of Executive Vice President, Chief Generation Officer and Enterprise Operational Excellence in January 2023. Prior to that, Mr. Gillespie served as the Chief Generation Officer since 2020. R. Alexander Glenn 57 Senior Vice President and Chief Executive Officer, Duke Energy Florida and Midwest. Mr. Glenn assumed his current position in May 2021. Prior to that, Mr. Glenn served as Senior Vice President, State and Federal Regulatory Legal Support since 2017 and as State President of Duke Energy Florida's operations from 2012 to 2017. Dhiaa M. Jamil 66 Executive Vice President and Chief Operating Officer. Mr. Jamil assumed the role of Chief Operating Officer in May 2016. Prior to his current position, he held the title Executive Vice President and President, Regulated Generation and Transmission since June 2015. Prior to that, he served as Executive Vice President and President, Regulated Generation since August 2014. He served as Executive Vice President and President of Duke Energy Nuclear from March 2013 to August 2014, and was Chief Nuclear Officer from February 2008 to February 2013. Julia S. Janson 58 Executive Vice President and Chief Executive Officer, Duke Energy Carolinas. Ms. Janson assumed her current position in May 2021. Prior to that she held the position of Executive Vice President, External Affairs and President, Carolinas Region since October 2019 and the position of Executive Vice President, External Affairs and Chief Legal Officer since November 2018. She originally assumed the position of Executive Vice President, Chief Legal Officer and Corporate Secretary in December 2012, and then assumed the responsibilities for External Affairs in February 2016. Cynthia S. Lee

56 Vice President, Chief Accounting Officer and Controller. Ms. Lee assumed her role as Vice President, Chief Accounting Officer and Controller in May 2021. Prior to that, she served as Director, Investor Relations since June 2019 and in various roles within the Corporate Controller's organization after joining the Corporation and its affiliates in 2002. Ronald R. Reising 62 Senior Vice President and Chief Human Resources Officer. Mr. Reising assumed his current position in July 2020. Prior to that, he served as Senior Vice President of Operations Support since 2014. Prior to that, he served as Chief Procurement Officer since 2006. Louis E. Renjel 49 Senior Vice President, External Affairs and Communications. Mr. Renjel assumed his current position in May 2021. Prior to that, he served as Senior Vice President of Federal Government and Corporate Affairs since 2019, and as Vice President, Federal Government Affairs and Strategic Policy since he joined Duke Energy in March 2017 until 2019. Prior to joining Duke Energy, Mr. Renjel served as Vice President of Strategic Infrastructure since 2009 for CSX Corp and as their Director of Environmental and Government Affairs from 2006 to 2008. Harry K. Sideris 52 Executive Vice President, Customer Experience, Solutions and Services. Mr. Sideris assumed his current position in October 2019. Prior to that, he served as Senior Vice President and Chief Distribution Officer since June 2018; State President, Florida from January 2017 to June 2018; Senior Vice President of Environmental Health and Safety from August 2014 to January 2017; and Vice President of Power Generations for the company's Fossil/Hydro Operations in the western portions of North Carolina and South Carolina from July 2012 to August 2014. Steven K. Young 64 Executive Vice President, Chief Strategy and Commercial Officer. Mr. Young assumed the position of Executive Vice President, Chief Strategy and Commercial Officer in September 2022. Prior to that, he held the position of Executive Vice President and Chief Financial Officer from August 2013 through August 2022; Vice President, Chief Accounting Officer and Controller, assuming the role of Chief Accounting Officer in July 2012 and the role of Controller in December 2006. ##TABLE_END(a) The ages of the officers provided are as of January 31, 2023. There are no family relationships between any of the executive officers, nor any arrangement or understanding between any executive officer and any other person involved in officer selection. ##TABLE_START BUSINESS ##TABLE_ENDEnvironmental Matters The Duke Energy Registrants are subject to federal, state and local laws and regulations with regard to air and water quality, hazardous and solid waste disposal and other environmental matters. Environmental laws and regulations affecting the Duke Energy Registrants include, but are not limited to: The Clean Air Act, as well as state laws and regulations impacting air emissions, including State Implementation Plans related to existing and new national ambient air quality standards for ozone and particulate matter. Owners and/or operators of air emission sources are responsible for obtaining permits and for annual compliance and reporting. The Clean Water Act, which requires permits for facilities that discharge wastewaters into navigable waters. The Comprehensive Environmental Response, Compensation and Liability Act, which can require any individual or entity that currently owns or in the past owned or operated a disposal site,

as well as transporters or generators of hazardous substances sent to a disposal site, to share in remediation costs. The National Environmental Policy Act, which requires federal agencies to consider potential environmental impacts in their permitting and licensing decisions, including siting approvals. Coal Ash Act, as amended, which establishes requirements regarding the use and closure of existing ash basins, the disposal of ash at active coal plants and the handling of surface water and groundwater impacts from ash basins in North Carolina. The Solid Waste Disposal Act, as amended by RCRA, which creates a framework for the proper management of hazardous and nonhazardous solid waste; classifies CCR as nonhazardous waste; and establishes standards for landfill and surface impoundment placement, design, operation and closure, groundwater monitoring, corrective action, and post-closure care. The Toxic Substances Control Act, which gives EPA the authority to require reporting, recordkeeping and testing requirements, and to place restrictions relating to chemical substances and/or mixtures, including polychlorinated biphenyls. For more information on environmental matters, see Notes 5 and 10 to the Consolidated Financial Statements, Commitments and Contingencies Environmental and "Asset Retirement Obligations," respectively, and the Other Matters section of Item 7 Management's Discussion and Analysis. Except as otherwise described in these sections, costs to comply with current federal, state and local provisions regulating the discharge of materials into the environment or other potential costs related to protecting the environment are incorporated into the routine cost structure of our various business segments and are not expected to have a material adverse effect on the competitive position, consolidated results of operations, cash flows or financial position of the Duke Energy Registrants. The "Other Matters" section of Item 7 Management's Discussion and Analysis includes more information on certain environmental regulations and a discussion of Global Climate Change including the potential impact of current and future legislation related to GHG emissions on the Duke Energy Registrants' operations. Recently passed and potential future environmental statutes and regulations could have a significant impact on the Duke Energy Registrants results of operations, cash flows or financial position. However, if and when such statutes and regulations become effective, the Duke Energy Registrants will seek appropriate regulatory recovery of costs to comply within its regulated operations. DUKE ENERGY CAROLINAS ##TABLE_START ##TABLE_ENDDuke Energy Carolinas is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina. Duke Energy Carolinas service area covers approximately 24,000 square miles and supplies electric service to 2.8 million residential, commercial and industrial customers. For information about Duke Energy Carolinas generating facilities, see Item 2, Properties. Duke Energy Carolinas is subject to the regulatory provisions of the NCUC, PSCSC, NRC and FERC. Substantially all of Duke Energy Carolinas' operations are regulated and qualify for regulatory accounting. Duke Energy Carolinas operates one reportable business segment, EUI. For additional information regarding this business segment, including financial information, see Note 3 to the

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Consolidated Financial Statements, Business Segments. PROGRESS ENERGY ##TABLE_START ##TABLE_ENDProgress Energy is a public utility holding company primarily engaged in the regulated electric utility business and is subject to regulation by the FERC. Progress Energy conducts operations through its wholly owned subsidiaries, Duke Energy Progress and Duke Energy Florida. When discussing Progress Energys financial information, it necessarily includes the results of Duke Energy Progress and Duke Energy Florida. Substantially all of Progress Energys operations are regulated and qualify for regulatory accounting. Progress Energy operates one reportable business segment, EUI. For additional information regarding this business segment, including financial information, see Note 3 to the Consolidated Financial Statements, Business Segments. DUKE ENERGY PROGRESS ##TABLE_START ##TABLE_ENDDuke Energy Progress is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina. Duke Energy Progress service area covers approximately 29,000 square miles and supplies electric service to approximately 1.7 million residential, commercial and industrial customers. For information about Duke Energy Progress generating facilities, see Item 2, Properties. Duke Energy Progress is subject to the regulatory provisions of the NCUC, PSCSC, NRC and FERC. Substantially all of Duke Energy Progress operations are regulated and qualify for regulatory accounting. Duke Energy Progress operates one reportable business segment, EUI. For additional information regarding this business segment, including financial information, see Note 3 to the Consolidated Financial Statements, Business Segments. PART I DUKE ENERGY FLORIDA ##TABLE_START ##TABLE_ENDDuke Energy Florida is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of Florida. Duke Energy Floridas service area covers approximately 13,000 square miles and supplies electric service to approximately 1.9 million residential, commercial and industrial customers. For information about Duke Energy Floridas generating facilities, see Item 2, Properties. Duke Energy Florida is subject to the regulatory provisions of the FPSC, NRC and FERC. Substantially all of Duke Energy Floridas operations are regulated and qualify for regulatory accounting. Duke Energy Florida operates one reportable business segment, EUI. For additional information regarding this business segment, including financial information, see Note 3 to the Consolidated Financial Statements, Business Segments. DUKE ENERGY OHIO ##TABLE_START ##TABLE_ENDDuke Energy Ohio is a regulated public utility primarily engaged in the transmission and distribution of electricity in portions of Ohio and Kentucky, in the generation and sale of electricity in portions of Kentucky and the transportation and sale of natural gas in portions of Ohio and Kentucky. Duke Energy Ohio also conducts competitive auctions for retail electricity supply in Ohio whereby recovery of the energy price is from retail customers. Operations in Kentucky are conducted through its wholly owned subsidiary, Duke Energy Kentucky. References herein to Duke Energy Ohio include Duke Energy Ohio and its subsidiaries, unless otherwise noted. Duke Energy Ohio is subject to the regulatory provisions of the PUCO, KPSC, PHMSA and FERC. Duke Energy Ohios service area covers approximately 3,000 square miles and supplies electric service to approximately 900,000 residential, commercial and industrial customers and provides transmission and distribution services for natural gas to approximately 550,000 customers. For information about Duke Energy Ohio's generating facilities, see Item 2, Properties. KO Transmission, a wholly owned subsidiary of Duke Energy Ohio, is an interstate pipeline company engaged in the business of transporting natural gas and is subject to the rules and regulations of FERC. KO Transmission's 90-mile pipeline supplies natural gas to Duke Energy Ohio and interconnects with the Columbia Gulf Transmission pipeline and Tennessee Gas Pipeline. An approximately 70-mile portion of KO Transmission's pipeline facilities is co-owned by Columbia Gas Transmission, LLC. KO Transmission sold all of its pipeline facilities and related real property to Columbia Gas Transmission, LLC on February 1, 2023, for approximately book value. Substantially all of Duke Energy Ohio's operations are regulated and qualify for regulatory accounting. Duke Energy Ohio has two reportable segments, EUI and GUI. For additional information on these business segments, including financial information, see Note 3 to the Consolidated Financial Statements, Business Segments. DUKE ENERGY INDIANA ##TABLE_START ##TABLE_ENDDuke Energy Indiana is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of Indiana. Duke Energy Indianas service area covers 23,000 square miles and supplies electric service to 890,000 residential, commercial and industrial customers. For information about Duke Energy Indiana's generating facilities, see Item 2, Properties. Duke Energy Indiana is subject to the regulatory provisions of the IURC and FERC. In 2021, Duke Energy executed an agreement providing for an investment in Duke Energy Indiana by GIC. The transaction was completed following two closings. For additional information, see Note 2 to the Consolidated Financial Statements, "Dispositions." Substantially all of Duke Energy Indianas operations are regulated and qualify for regulatory accounting. Duke Energy Indiana operates one reportable business segment, EUI. For additional information regarding this business segment, including financial information, see Note 3 to the Consolidated Financial Statements, Business Segments. PIEDMONT ##TABLE_START ##TABLE_ENDPiedmont is a regulated public utility primarily engaged in the distribution of natural gas to over 1.1 million residential, commercial, industrial and power generation customers in portions of North Carolina, South Carolina and Tennessee, including customers served by municipalities who are wholesale customers. For information about Piedmont's natural gas distribution facilities, see Item 2, "Properties." Piedmont is subject to the regulatory provisions of the NCUC, PSCSC, TPUC, PHMSA and FERC. Substantially all of Piedmonts operations are regulated and qualify for regulatory accounting. Piedmont operates one reportable business segment, GUI. For additional information regarding this business segment, including financial information, see Note 3 to the Consolidated Financial Statements, Business Segments. ITEM 1A. RISK FACTORS ##TABLE_START ##TABLE_ENDIn addition to other disclosures within this Form 10-K, including "Management's Discussion and Analysis of Financial Condition and Results of Operations Matters Impacting Future Results" for each registrant in Item 7, and other documents filed with the SEC from time to time, the following factors should be considered in evaluating Duke Energy and its subsidiaries. Such factors could affect actual results of operations and cause results to differ substantially from those currently expected or sought. Unless otherwise indicated, risk factors discussed below generally relate to risks associated with all of the Duke Energy Registrants. Risks identified at the Subsidiary Registrant level are generally applicable to Duke Energy. ##TABLE_START RISK FACTORS ##TABLE_ENDBUSINESS STRATEGY RISKS Duke Energys future results could be adversely affected if it is unable to implement its business strategy including achieving its carbon emissions reduction goals. Duke Energys results of operations depend, in significant part, on the extent to which it can implement its business strategy successfully. Duke Energy's clean energy transition, which includes achieving net-zero carbon emissions from electricity generation by 2050, modernizing the regulatory construct, transforming the customer experience, and digital transformation, is subject to business, policy, regulatory, technology, economic and competitive uncertainties and contingencies, many of which are beyond its control and may make those goals difficult to achieve. Federal or state policies could be enacted that restrict the availability of fuels or generation technologies, such as natural gas or nuclear power, that enable Duke Energy to reduce its carbon emissions. Supportive policies may be needed to facilitate the siting and cost recovery of transmission and distribution upgrades needed to accommodate the build out of large volumes of renewables and energy storage. Further, the approval of our state regulators will be necessary for the company to continue to retire existing carbon emitting assets or make investments in new generating capacity. The company may be constrained by the ability to procure resources or labor needed to build new generation at a reasonable price as well as to construct projects on time. In addition, new technologies that are not yet commercially available or are unproven at utility scale will likely be needed including new resources capable of following electric load over long durations such as advanced nuclear, hydrogen and long-duration storage, If these technologies are not developed or are not available at reasonable prices, or if we invest in early stage technologies that are then supplanted by technological breakthroughs, Duke Energys ability to achieve a net-zero target by 2050 at a cost-effective price could be at risk. Achieving our carbon reduction goals will require continued operation of our existing carbon-free technologies including nuclear and renewables. The rapid transition to and expansion of certain low-carbon resources, such as renewables without cost-effective storage, may challenge our ability to meet customer expectations of reliability in a carbon constrained environment. Our nuclear fleet is central to our ability to meet these objectives and customer expectations. We are continuing to seek to renew the operating licenses of the 11 reactors we operate at six nuclear stations for an additional 20 years, extending their operating lives to and beyond midcentury. Failure to receive approval from the NRC for the relicensing of any of these reactors could affect our ability to achieve a net-zero target by 2050. As a consequence, Duke Energy may not be able to fully implement or realize the anticipated results of its energy transition strategy, which may have an adverse effect on its financial condition. REGULATORY, LEGISLATIVE AND LEGAL RISKS The Duke Energy Registrants regulated utility revenues, earnings and results of operations are dependent on state legislation and regulation that affect electric generation, electric and natural gas transmission, distribution and related activities, which may limit their ability to recover costs. The Duke Energy Registrants regulated electric and natural gas utility businesses are regulated on a cost-of-service/rate-of-return basis subject to statutes and regulatory commission rules and procedures of North Carolina, South Carolina, Florida, Ohio, Tennessee, Indiana and Kentucky. If the Duke Energy Registrants regulated utility earnings exceed the returns established by the state utility commissions, retail electric and natural gas rates may be subject to review and possible reduction by the commissions, which may decrease the Duke Energy Registrants earnings. Additionally, if regulatory or legislative bodies do not allow recovery of costs incurred in providing service, or do not do so on a timely basis, the Duke Energy Registrants earnings could be negatively impacted. Differences in regulation between jurisdictions with concurrent operations, such as North Carolina and South Carolina in Duke Energy Carolinas' and Duke Energy Progress' service territory, may also result in failure to recover costs. If legislative and regulatory structures were to evolve in such a way that the Duke Energy Registrants exclusive rights to serve their regulated customers were eroded, their earnings could be negatively impacted. Federal and state regulations, laws, commercialization and reduction of costs and other efforts designed to promote and expand the use of EE measures and distributed generation technologies, such as private solar and battery storage, in Duke Energy service territories could reduce recovery of fixed costs in Duke Energy service territories or result in customers leaving the electric distribution system and an increase in customer net energy metering, which allows customers with private solar to receive bill credits for surplus power at the full retail amount. Over time, customer adoption of these technologies could result in Duke Energy not being able to fully recover the costs and investment in generation. State regulators have approved various mechanisms to stabilize natural gas utility margins, including margin decoupling in North Carolina and rate stabilization in South Carolina. State regulators have approved other margin stabilizing mechanisms that, for example, allow for recovery of margin losses associated with negotiated transactions designed to retain large volume customers that could use alternative fuels or that may otherwise directly access natural gas supply through their own connection to an interstate pipeline. If regulators decided to discontinue the Duke Energy Registrants' use of tariff mechanisms, it would negatively impact results of operations, financial position and cash flows. In addition, regulatory authorities also review whether natural gas costs are prudently incurred and can disallow the recovery of a portion of natural gas costs that the Duke Energy Registrants seek to recover from customers, which would adversely impact earnings. The rates that the Duke Energy Registrants regulated utility businesses are allowed to charge are established by state utility commissions in rate case proceedings, which may limit their ability to recover costs and earn an appropriate return on investment. The rates that the Duke Energy Registrants regulated utility businesses are allowed to charge significantly influences the results of operations, financial position and cash flows of the Duke Energy Registrants. The regulation of the rates that the regulated utility businesses charge customers is determined, in large part, by state utility commissions in rate case proceedings. Negative decisions made by these regulators, or by any court on appeal of a rate case proceeding, have, and in the future could have, a material adverse effect on the Duke Energy Registrants results of operations, financial position or cash flows and affect the ability of the Duke Energy Registrants to recover costs and an appropriate return on the significant infrastructure investments being made. ##TABLE_START RISK FACTORS ##TABLE_ENDDeregulation or restructuring in the electric industry may result in increased competition and unrecovered costs that could adversely affect the Duke Energy Registrants results of operations, financial position or cash flows and their utility businesses. Increased competition resulting from deregulation or restructuring legislation could have a significant adverse impact on the Duke Energy Registrants results of operations, financial position or cash flows and their utility businesses. If the retail jurisdictions served by the Duke Energy Registrants become subject to deregulation, the impairment of assets, loss of retail customers, lower profit margins or increased costs of capital, and recovery of stranded costs could have a significant adverse financial impact on the Duke Energy Registrants. Stranded costs primarily include the generation assets of the Duke Energy Registrants whose value in a competitive marketplace may be less than their current book value, as well as above-market purchased power commitments from QFs from whom the Duke Energy Registrants are legally obligated to purchase energy at an avoided cost rate under PURPA. The Duke Energy Registrants cannot predict the extent and timing of entry by additional competitors into the electric markets. The Duke Energy Registrants cannot predict if or when they will be subject to changes in legislation or regulation, nor can they predict the impact of these changes on their results of operations, financial position or cash flows. The Duke Energy Registrants businesses are subject to extensive federal regulation and a wide variety of laws and governmental policies, including taxes and environmental regulations, that may change over time in ways that affect operations and costs. The Duke Energy Registrants are subject to regulations under a wide variety of U.S. federal and state regulations and policies, including by FERC, NRC, EPA and various other federal agencies as well as the North American Electric Reliability Corporation. Regulation affects almost every aspect of the Duke Energy Registrants businesses, including, among other things, their ability to: take fundamental business management actions; determine the terms and rates of transmission and distribution services; make acquisitions; issue equity or debt securities; engage in transactions with other subsidiaries and affiliates; and pay dividends upstream to the Duke Energy Registrants. Changes to federal regulations are continuous and ongoing. There can be no assurance that laws, regulations and policies will not be changed in ways that result in material modifications of business models and objectives or affect returns on investment by restricting activities and products, subjecting them to escalating costs, causing delays, or prohibiting them outright. The Duke Energy Registrants are subject to numerous environmental laws and regulations requiring significant capital expenditures that can increase the cost of operations, and which may impact or limit business plans, or cause exposure to environmental liabilities. The Duke Energy Registrants are subject to numerous environmental laws and regulations affecting many aspects of their present and future operations, including CCRs, air emissions, water quality, wastewater discharges, solid waste and hazardous waste. These laws and regulations can result in increased capital, operating and other costs. These laws and regulations generally require the Duke Energy Registrants to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Compliance with environmental laws and regulations can require significant expenditures, including expenditures for cleanup costs and damages arising from contaminated properties. Failure to comply with environmental regulations may result in the imposition of fines, penalties and injunctive measures affecting operating assets. The steps the Duke Energy Registrants could be required to take to ensure their facilities are in compliance could be prohibitively expensive. As a result, the Duke Energy Registrants may be required to shut down or alter the operation of their facilities, which may cause the Duke Energy Registrants to incur losses. Further, the Duke Energy Registrants may not be successful in recovering capital and operating costs incurred to comply with new environmental regulations through existing regulatory rate structures and their contracts with customers. Also, the Duke Energy Registrants may not be able to obtain or maintain from time to time all required environmental regulatory approvals for their operating assets or development projects. Delays in obtaining any required environmental regulatory approvals, failure to obtain and comply with them or changes in environmental laws or regulations to more stringent compliance levels could result in additional costs of operation for existing facilities or development of new facilities being prevented, delayed or subject to additional costs. Although it is not expected that the costs to comply with current environmental regulations will have a material adverse effect on the Duke Energy Registrants results of operations, financial position and cash flows due to regulatory cost recovery, the Duke Energy Registrants are at risk that the costs of complying with environmental regulations in the future will have such an effect. The EPA has enacted or proposed federal regulations governing the management of cooling water intake structures, wastewater and CO_2 emissions. New state legislation could impose carbon reduction goals that are more aggressive than the company's plans. These regulations may require the Duke Energy Registrants to make additional capital expenditures and increase operating and maintenance costs. The Duke Energy Registrants' operations, capital expenditures and financial results may be affected by regulatory changes related to the impacts of global climate change. There is continued concern, and increasing activism, both nationally and internationally, about climate change. The EPA and state regulators have, and may adopt and implement, additional regulations to restrict emissions of GHGs to address global climate change. Certain local and state jurisdictions have also enacted laws to restrict or prevent new natural gas infrastructure. Increased regulation of GHG emissions could impose significant additional costs on the Duke Energy Registrants' electric and natural gas operations, their suppliers and customers and affect demand for energy conservation and renewable products, which could impact both our electric and natural gas businesses. Regulatory changes could also result in generation facilities to be retired earlier than planned to meet our net-zero 2050 goal. Though we would plan to seek cost recovery for investments related to GHG emissions reductions through regulatory rate structures, changes in the regulatory climate could result in the delay in or failure to fully recover such costs and investment in generation. OPERATIONAL RISKS The Duke Energy Registrants results of operations may be negatively affected by overall market, economic and other conditions that are beyond their control. Sustained downturns or sluggishness in the economy generally affect the markets in which the Duke Energy Registrants operate and negatively influence operations. Declines in demand for electricity or natural gas as a result of economic downturns in the Duke Energy Registrants regulated service territories will reduce overall sales and lessen cash flows, especially as industrial customers reduce production and, therefore, consumption of electricity and the use of natural gas. Although the Duke Energy Registrants regulated electric and natural gas businesses are subject to regulated allowable rates of return and recovery of certain costs, such as fuel and purchased natural gas costs, under periodic adjustment clauses, overall declines in electricity or natural gas sold as a result of economic downturn or recession could reduce revenues and cash flows, thereby diminishing results of operations. ##TABLE_START RISK FACTORS ##TABLE_ENDA continuation of adverse economic conditions including economic downturn or high commodity prices could also negatively impact the financial stability of certain of our customers and result in their inability to pay for electric and natural gas services. This could lead to increased bad debt expense and higher allowance for doubtful account reserves for the Duke Energy Registrants and result in delayed or unrecovered operating costs and lower financial results. Additionally, prolonged economic downturns that negatively impact the Duke Energy Registrants results of operations and cash flows could result in future material impairment charges to write-down the carrying value of certain assets, including goodwill, to their respective fair values. The Duke Energy Registrants also monitor the impacts of inflation on the procurement of goods and services and seek to minimize its effects in future periods through pricing strategies, productivity improvements, and cost reductions. Rapidly rising prices as a result of inflation or other factors may impact the ability of the company to recover costs timely or execute on its business strategy including the achievement of growth objectives. The Duke Energy Registrants sell electricity into the spot market or other competitive power markets on a contractual basis. With respect to such transactions, the Duke Energy Registrants are not guaranteed any rate of return on their capital investments through mandated rates, and revenues and results of operations are likely to depend, in large part, upon prevailing market prices. These market prices may fluctuate substantially over relatively short periods of time and could negatively impact the company's ability to accurately forecast the financial impact or reduce the Duke Energy Registrants revenues and margins, thereby diminishing results of operations. Factors that could impact sales volumes, generation of electricity and market prices at which the Duke Energy Registrants are able to sell electricity and natural gas are as follows: weather conditions, including abnormally mild winter or summer weather that cause lower energy or natural gas usage for heating or cooling purposes, as applicable, and periods of low rainfall that decrease the ability to operate facilities in an economical manner; supply of and demand for energy commodities; transmission or transportation constraints or inefficiencies that impact nonregulated energy operations; availability of purchased power; availability of competitively priced alternative energy sources, which are preferred by some customers over electricity produced from coal, nuclear or natural gas plants, and customer usage of energy-efficient equipment that reduces energy demand; natural gas, crude oil and refined products production levels and prices; ability to procure satisfactory levels of inventory, including materials, supplies, and fuel such as coal, natural gas and uranium; and capacity and transmission service into, or out of, the Duke Energy Registrants markets. Natural disasters or operational accidents may adversely affect the Duke Energy Registrants operating results. Natural disasters or operational accidents within the company or industry (such as forest fires, earthquakes, hurricanes or natural gas transmission pipeline explosions) could have direct or indirect impacts to the Duke Energy Registrants or to key contractors and suppliers. Further, the generation of electricity and the transportation and storage of natural gas involve inherent operating risks that may result in accidents involving serious injury or loss of life, environmental damage or property damage. Such events could impact the Duke Energy Registrants through changes to policies, laws and regulations whose compliance costs have a significant impact on the Duke Energy Registrants results of operations, financial position and cash flows. In addition, if a serious operational accident were to occur, existing insurance policies may not cover all of the potential exposures or the actual amount of loss incurred, including potential litigation awards. Any losses not covered by insurance, or any increases in the cost of applicable insurance as a result of such accident, could have a material adverse effect on the results of operations, financial position, cash flows and reputation of the Duke Energy Registrants. The reputation and financial condition of the Duke Energy Registrants could be negatively impacted due to their obligations to comply with federal and state regulations, laws, and other legal requirements that govern the operations, assessments, storage, closure, remediation, disposal and monitoring relating to CCR, the high costs and new rate impacts associated with implementing these new CCR-related requirements and the strategies and methods necessary to implement these requirements in compliance with these legal obligations. As a result of electricity produced for decades at coal-fired power plants, the Duke Energy Registrants manage large amounts of CCR that are primarily stored in dry storage within landfills or combined with water in surface impoundments, all in compliance with applicable regulatory requirements. A CCR-related operational incident could have a material adverse impact on the reputation and results of operations, financial position and cash flows of the Duke Energy Registrants. During 2015, EPA regulations were enacted related to the management of CCR from power plants. These regulations classify CCR as nonhazardous waste under the RCRA and apply to electric generating sites with new and existing landfills and, new and existing surface impoundments, and establish requirements regarding landfill design, structural integrity design and assessment criteria for surface impoundments, groundwater monitoring, protection and remedial procedures and other operational and reporting procedures for the disposal and management of CCR. In addition to the federal regulations, CCR landfills and surface impoundments will continue to be regulated by existing state laws, regulations and permits, as well as additional legal requirements that may be imposed in the future, such as the settlement reached with the NCDEQ to excavate seven of the nine remaining coal ash basins in North Carolina, and partially excavate the remaining two, and the EPA's January 11, 2022, issuance of a letter interpreting the CCR Rule, including its applicability and closure provisions. These federal and state laws, regulations and other legal requirements may require or result in additional expenditures, including increased operating and maintenance costs, which could affect the results of operations, financial position and cash flows of the Duke Energy Registrants. The Duke Energy Registrants will continue to seek full cost recovery for expenditures through the normal ratemaking process with state and federal utility commissions, who permit recovery in rates of necessary and prudently incurred costs associated with the Duke Energy Registrants regulated operations, and through other wholesale contracts with terms that contemplate recovery of such costs, although there is no guarantee of full cost recovery. In addition, the timing for and amount of recovery of such costs could have a material adverse impact on Duke Energy's cash flows. ##TABLE_START RISK FACTORS ##TABLE_ENDThe Duke Energy Registrants have recognized significant AROs related to these CCR-related requirements. Closure activities began in 2015 at the four sites specified as high priority by the Coal Ash Act and at the W.S. Lee Steam Station site in South Carolina in connection with other legal requirements. Excavation at these sites involves movement of CCR materials to off-site locations for use as structural fill, to appropriately engineered off-site or on-site lined landfills or conversion of the ash for beneficial use. Duke Energy has completed excavation of coal ash at the four high-priority North Carolina sites. At other sites, planning and closure methods have been studied and factored into the estimated retirement and management costs, and closure activities have commenced. As the closure and CCR management work progresses and final closure plans and corrective action measures are developed and approved at each site, the scope and complexity of work and the amount of CCR material could be greater than estimates and could, therefore, materially increase compliance expenditures and rate impacts. The Duke Energy Registrants results of operations, financial position and cash flows may be negatively affected by a lack of growth or slower growth in the number of customers, or decline in customer demand or number of customers. Growth in customer accounts and growth of customer usage each directly influence demand for electricity and natural gas and the need for additional power generation and delivery facilities. Customer growth and customer usage are affected by several factors outside the control of the Duke Energy Registrants, such as mandated EE measures, demand-side management goals, distributed generation resources and economic and demographic conditions, such as inflation and interest rate volatility, population changes, job and income growth, housing starts, new business formation and the overall level of economic activity. In addition, certain regulatory and legislative bodies have passed legislation implementing the extension of certain tax credits to be used toward the costs of residential solar installation or have introduced or are considering requirements and/or incentives to reduce energy consumption by certain dates in response to concerns related to climate change. Additionally, technological advances driven by federal laws mandating new levels of EE in end-use electric and natural gas devices or other improvements in or applications of technology could lead to declines in per capita energy consumption. Advances in distributed generation technologies that produce power, including fuel cells, microturbines, wind turbines and solar cells, may reduce the cost of alternative methods of producing power to a level competitive with central power station electric production utilized by the Duke Energy Registrants. In addition, the electrification of buildings and appliances currently relying on natural gas could reduce the number of customers in our natural gas distribution business. Some or all of these factors could result in a lack of growth or decline in customer demand for electricity or number of customers and may cause the failure of the Duke Energy Registrants to fully realize anticipated benefits from significant capital investments and expenditures, which could have a material adverse effect on their results of operations, financial position and cash flows. Furthermore, the Duke Energy Registrants currently have EE riders in place to recover the cost of EE programs in North Carolina, South Carolina, Florida, Indiana, Ohio and Kentucky. Should the Duke Energy Registrants be required to invest in conservation measures that result in reduced sales from effective conservation, regulatory lag in adjusting rates for the impact of these measures could have a negative financial impact. The Duke Energy Registrants future results of operations may be impacted by changing expectations and demands including heightened emphasis on environmental, social and governance concerns. Duke Energys ability to execute its strategy and achieve anticipated financial outcomes are influenced by the expectations of our customers, regulators, investors, and stakeholders. Those expectations are based in part on the core fundamentals of reliability and affordability but are also increasingly focused on our ability to meet rapidly changing demands for new and varied products, services and offerings. Additionally, the risks of global climate change continues to shape our customers sustainability goals and energy needs as well as the investment and financing criteria of investors. Failure to meet these increasing expectations or to adequately address the risks and external pressures from regulators, customers, investors and other stakeholders may impact Duke Energys reputation and affect its ability to achieve favorable outcomes in future rate cases and the results of operations for the Duke Energy Registrants. Furthermore, the increasing use of social media may accelerate and increase the potential scope of negative publicity we might receive and could increase the negative impact on our reputation, business, results of operations, and financial condition. As it relates to electric generation, a diversified fleet with increasingly clean generation resources may facilitate more efficient financing and lower costs. Conversely, jurisdictions utilizing more carbon-intensive generation such as coal may experience difficulty attracting certain investors and obtaining the most economical financing terms available. Furthermore, with this heightened emphasis on environmental, social, and governance concerns, and climate change in particular, there is an increased risk of litigation, activism, and legislation from groups both in support of and opposed to various environmental, social and governance initiatives, which could cause delays and increase the costs of our clean energy transition. The Duke Energy Registrants operating results may fluctuate on a seasonal and quarterly basis and can be negatively affected by changes in weather conditions and severe weather, including extreme weather conditions and changes in weather patterns from climate change. Electric power generation and natural gas distribution are generally seasonal businesses. In most parts of the U.S., the demand for power peaks during the warmer summer months, with market prices also typically peaking at that time. In other areas, demand for power peaks during the winter. Demand for natural gas peaks during the winter months. Further, changing frequency or magnitude of extreme weather conditions such as hurricanes, droughts, heat waves, winter storms and severe weather, including from climate change, could cause these seasonal fluctuations to be more pronounced. As a result, the overall operating results of the Duke Energy Registrants businesses may fluctuate substantially on a seasonal and quarterly basis and thus make period-to-period comparison less relevant. Sustained severe drought conditions could impact generation by hydroelectric plants, as well as fossil and nuclear plant operations, as these facilities use water for cooling purposes and for the operation of environmental compliance equipment. Furthermore, destruction caused by severe weather events, such as hurricanes, flooding, tornadoes, severe thunderstorms, snow and ice storms, including from climate change, can result in lost operating revenues due to outages, property damage, including downed transmission and distribution lines, and additional and unexpected expenses to mitigate storm damage. The cost of storm restoration efforts may not be fully recoverable through the regulatory process. ##TABLE_START RISK FACTORS ##TABLE_ENDThe Duke Energy Registrants sales may decrease if they are unable to gain adequate, reliable and affordable access to transmission assets. The Duke Energy Registrants depend on transmission and distribution facilities owned and operated by utilities and other energy companies to deliver electricity sold to the wholesale market. In addition, the growth of renewables and energy storage will put strains on existing transmission assets and require transmission and distribution upgrades. The FERCs power transmission regulations require wholesale electric transmission services to be offered on an open-access, non-discriminatory basis. If transmission is disrupted, or if transmission capacity is inadequate, the Duke Energy Registrants ability to sell and deliver products may be hindered. The different regional power markets have changing regulatory structures, which could affect growth and performance in these regions. In addition, the ISOs who oversee the transmission systems in regional power markets have imposed in the past, and may impose in the future, price limitations and other mechanisms to address volatility in the power markets. These types of price limitations and other mechanisms may adversely impact the profitability of the Duke Energy Registrants wholesale power marketing business. The availability of adequate interstate pipeline transportation capacity and natural gas supply may decrease. The Duke Energy Registrants purchase almost all of their natural gas supply from interstate sources that must be transported to the applicable service territories. Interstate pipeline companies transport the natural gas to the Duke Energy Registrants' systems under firm service agreements that are designed to meet the requirements of their core markets. A significant disruption to interstate pipelines capacity or reduction in natural gas supply due to events including, but not limited to, operational failures or disruptions, hurricanes, tornadoes, floods, freeze off of natural gas wells, terrorist or cyberattacks or other acts of war or legislative or regulatory actions or requirements, including remediation related to integrity inspections or regulations and laws enacted to address climate change, could reduce the normal interstate supply of natural gas and thereby reduce earnings. Moreover, if additional natural gas infrastructure, including, but not limited to, exploration and drilling rigs and platforms, processing and gathering systems, offshore pipelines, interstate pipelines and storage, cannot be built at a pace that meets demand, then growth opportunities could be limited. Fluctuations in commodity prices or availability may adversely affect various aspects of the Duke Energy Registrants operations as well as their results of operations, financial position and cash flows. The Duke Energy Registrants are exposed to the effects of market fluctuations in the price of natural gas, coal, fuel oil, nuclear fuel, electricity and other energy-related commodities as a result of their ownership of energy-related assets. Fuel costs are recovered primarily through cost recovery clauses, subject to the approval of state utility commissions. Additionally, the Duke Energy Registrants are exposed to risk that counterparties will not be able to fulfill their obligations. Disruption in the delivery of fuel, including disruptions as a result of, among other things, bankruptcies, transportation delays, weather, labor relations, force majeure events or environmental regulations affecting any of these fuel suppliers, could limit the Duke Energy Registrants' ability to operate their facilities. Should counterparties fail to perform, the Duke Energy Registrants might be forced to replace the underlying commitment at prevailing market prices possibly resulting in losses in addition to the amounts, if any, already paid to the counterparties. Certain of the Duke Energy Registrants hedge agreements may result in the receipt of, or posting of, collateral with counterparties, depending on the daily market-based calculation of financial exposure of the derivative positions. Fluctuations in commodity prices that lead to the return of collateral received and/or the posting of collateral with counterparties could negatively impact liquidity. Downgrades in the Duke Energy Registrants credit ratings could lead to additional collateral posting requirements. The Duke Energy Registrants continually monitor derivative positions in relation to market price activity. Cyberattacks and data security breaches could adversely affect the Duke Energy Registrants' businesses. Cybersecurity risks have increased in recent years as a result of the proliferation of new technologies and the increased sophistication, magnitude and frequency of cyberattacks and data security breaches. Duke Energy relies on the continued operation of sophisticated digital information technology systems and network infrastructure, which are part of an interconnected regional grid. Additionally, connectivity to the internet continues to increase through grid modernization and other operational excellence initiatives. Because of the critical nature of the infrastructure, increased connectivity to the internet and technology systems inherent vulnerability to disability or failures due to hacking, viruses, acts of war or terrorism or other types of data security breaches, the Duke Energy Registrants face a heightened risk of cyberattack from foreign or domestic sources and have been subject, and will likely continue to be subject, to attempts to gain unauthorized access to information and/or information systems or to disrupt utility operations through computer viruses and phishing attempts either directly or indirectly through its material vendors or related third parties. In the event of a significant cybersecurity breach on either the Duke Energy Registrants or with one of our material vendors or related third parties, the Duke Energy Registrants could (i) have business operations disrupted, including the disruption of the operation of our natural gas and electric assets and the power grid, theft of confidential company, employee, retiree, shareholder, vendor or customer information, and general business systems and process interruption or compromise, including preventing the Duke Energy Registrants from servicing customers, collecting revenues or the recording, processing and/or reporting financial information correctly, (ii) experience substantial loss of revenues, repair and restoration costs, penalties and costs for lack of compliance with relevant regulations, implementation costs for additional security measures to avert future cyberattacks and other financial loss and (iii) be subject to increased regulation, litigation and reputational damage. While Duke Energy maintains insurance relating to cybersecurity events, such insurance is subject to a number of exclusions and may be insufficient to offset any losses, costs or damage experienced. Also, the market for cybersecurity insurance is relatively new and coverage available for cybersecurity events is evolving as the industry matures. ##TABLE_START RISK FACTORS ##TABLE_ENDThe Duke Energy Registrants are subject to standards enacted by the North American Electric Reliability Corporation and enforced by FERC regarding protection of the physical and cybersecurity of critical infrastructure assets required for operating North America's bulk electric system. The Duke Energy Registrants are also subject to regulations set by the Nuclear Regulatory Commission regarding the protection of digital computer and communication systems and networks required for the operation of nuclear power plants. The Duke Energy Registrants that operate designated critical pipelines that transport natural gas are also subject to security directives issued by the Department of Homeland Security's Transportation Security Administration (TSA) requiring such registrants to implement specific cybersecurity mitigation measures. While the Duke Energy Registrants believe they are in compliance with, or, in the case of recent TSA security directives, are in the process of implementing such standards and regulations, the Duke Energy Registrants have from time to time been, and may in the future be, found to be in violation of such standards and regulations. In addition, compliance with or changes in the applicable standards and regulations may subject the Duke Energy Registrants to higher operating costs and/or increased capital expenditures as well as substantial fines for non-compliance. The Duke Energy Registrants operations have been and may be affected by pandemic health events, including COVID-19, in ways listed below and in ways the Duke Energy Registrants cannot predict at this time. The COVID-19 pandemic and efforts to respond to it have resulted in widespread adverse consequences on the global economy and on the Duke Energy Registrants customers, third-party vendors, and other parties with whom we do business. If the COVID-19 pandemic or other health epidemics and outbreaks that may occur are significantly prolonged, it could impact the Duke Energy Registrants' business strategy, results of operations, financial position and cash flows in the future as a result of delays in rate cases or other legal proceedings, an inability to obtain labor or equipment necessary for the construction of large capital projects, an inability to procure satisfactory levels of fuels or other necessary equipment for the continued production of electricity and delivery of natural gas, and the health and availability of our critical personnel and their ability to perform business functions. Duke Energy Ohios and Duke Energy Indianas membership in an RTO presents risks that could have a material adverse effect on their results of operations, financial position and cash flows. The rules governing the various regional power markets may change, which could affect Duke Energy Ohios and Duke Energy Indianas costs and/or revenues. To the degree Duke Energy Ohio and Duke Energy Indiana incur significant additional fees and increased costs to participate in an RTO, their results of operations may be impacted. Duke Energy Ohio and Duke Energy Indiana may be allocated a portion of the cost of transmission facilities built by others due to changes in RTO transmission rate design. Duke Energy Ohio and Duke Energy Indiana may be required to expand their transmission system according to decisions made by an RTO rather than their own internal planning process. In addition, RTOs have been developing rules associated with the allocation and methodology of assigning costs associated with improved transmission reliability, reduced transmission congestion and firm transmission rights that may have a financial impact on the results of operations, financial position and cash flows of Duke Energy Ohio and Duke Energy Indiana. As members of an RTO, Duke Energy Ohio and Duke Energy Indiana are subject to certain additional risks, including those associated with the allocation among RTO members, of losses caused by unreimbursed defaults of other participants in the RTO markets and those associated with complaint cases filed against an RTO that may seek refunds of revenues previously earned by RTO members. The Duke Energy Registrants may not recover costs incurred to begin construction on projects that are canceled. Duke Energys long-term strategy requires the construction of new projects, either wholly owned or partially owned, which involve a number of risks, including construction delays, delays in or failure to receive required regulatory approvals and/or sitting or environmental permits, nonperformance by equipment and other third-party suppliers, and increases in equipment and labor costs. To limit the risks of these construction projects, the Duke Energy Registrants enter into equipment purchase orders and construction contracts and incur engineering and design service costs in advance of receiving necessary regulatory approvals and/or siting or environmental permits. If any of these projects are canceled for any reason, including failure to receive necessary regulatory approvals and/or siting or environmental permits, significant cancellation penalties under the equipment purchase orders and construction contracts could occur. In addition, if any construction work or investments have been recorded as an asset, an impairment may need to be recorded in the event the project is canceled. The Duke Energy Registrants are subject to risks associated with their ability to obtain adequate insurance at acceptable costs. The financial condition of some insurance companies, actual or threatened physical or cyberattacks, and natural disasters, among other things, could have disruptive effects on insurance markets. The availability of insurance covering risks that the Duke Energy Registrants and their respective competitors typically insure against may decrease, and the insurance that the Duke Energy Registrants are able to obtain may have higher deductibles, higher premiums, and more restrictive policy terms. Further, the insurance policies may not cover all of the potential exposures or the actual amount of loss incurred. Any losses not covered by insurance, or any increases in the cost of applicable insurance, could adversely affect the results of operations, financial position or cash flows of the affected Duke Energy Registrant. Our business could be negatively affected as a result of actions of activist shareholders. While we strive to maintain constructive communications with our shareholders, activist shareholders may, from time to time, engage in proxy solicitations or advance shareholder proposals, or otherwise attempt to affect changes and assert influence on our Board and management. Perceived uncertainties as to the future direction or governance of the company may cause concern to our current or potential regulators, vendors or strategic partners, or make it more difficult to execute on our strategy or to attract and retain qualified personnel, which may have a material impact on our business and operating results. In addition, actions such as those described above could cause fluctuations in the trading price of our common stock, based on temporary or speculative market perceptions or other factors that do not necessarily reflect the underlying fundamentals and prospects of our business. ##TABLE_START RISK FACTORS ##TABLE_ENDNUCLEAR GENERATION RISKS Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida may incur substantial costs and liabilities due to their ownership and operation of nuclear generating facilities. Ownership interests in and operation of nuclear stations by Duke Energy Carolinas, Duke Energy Progress and

Duke Energy Florida subject them to various risks. These risks include, among other things: the potential harmful effects on the environment and human health resulting from the current or past operation of nuclear facilities and the storage, handling and disposal of radioactive materials; limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations; and uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives. Ownership and operation of nuclear generation facilities requires compliance with licensing and safety-related requirements imposed by the NRC. In the event of non-compliance, the NRC may increase regulatory oversight, impose fines or shut down a unit depending upon its assessment of the severity of the situation. Revised security and safety requirements promulgated by the NRC, which could be prompted by, among other things, events within or outside of the control of Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida, such as a serious nuclear incident at a facility owned by a third party, could necessitate substantial capital and other expenditures, as well as assessments to cover third-party losses. In addition, if a serious nuclear incident were to occur, it could have a material adverse effect on the results of operations, financial position, cash flows and reputation of the Duke Energy Registrants. LIQUIDITY, CAPITAL REQUIREMENTS AND COMMON STOCK RISKS The Duke Energy Registrants rely on access to short-term borrowings and longer-term debt and equity markets to finance their capital requirements and support their liquidity needs. Access to those markets can be adversely affected by a number of conditions, many of which are beyond the Duke Energy Registrants control. The Duke Energy Registrants businesses are significantly financed through issuances of debt and equity. The maturity and repayment profile of debt used to finance investments often does not correlate to cash flows from their assets. Accordingly, as a source of liquidity for capital requirements not satisfied by the cash flows from their operations and to fund investments originally financed through debt instruments with disparate maturities, the Duke Energy Registrants rely on access to short-term money markets as well as longer-term capital markets. The Subsidiary Registrants also rely on access to short-term intercompany borrowings. If the Duke Energy Registrants are not able to access debt or equity at competitive rates or at all, the ability to finance their operations and implement their strategy and business plan as scheduled could be adversely affected. An inability to access debt and equity may limit the Duke Energy Registrants ability to pursue improvements or acquisitions that they may otherwise rely on for future growth. Market disruptions may increase the cost of borrowing or adversely affect the ability to access one or more financial markets. Such disruptions could include: economic downturns, unfavorable capital market conditions, market prices for natural gas and coal, geopolitical risks, actual or threatened terrorist attacks, or the overall health of the energy industry. Additionally, rapidly rising interest rates could impact the ability to affordably finance the capital plan or increase rates to customers and could have an impact on our ability to execute on our clean energy transition. The availability of credit under Duke Energys Master Credit Facility depends upon the ability of the banks providing commitments under the facility to provide funds when their obligations to do so arise. Systemic risk of the banking system and the financial markets could prevent a bank from meeting its obligations under the facility agreement. Duke Energy maintains a revolving credit facility to provide backup for its commercial paper program and letters of credit to support variable rate demand tax-exempt bonds that may be put to the Duke Energy Registrant issuer at the option of the holder. The facility includes borrowing sublimits for the Duke Energy Registrants, each of whom is a party to the credit facility, and financial covenants that limit the amount of debt that can be outstanding as a percentage of the total capital for the specific entity. Failure to maintain these covenants at a particular entity could preclude Duke Energy from issuing commercial paper or the Duke Energy Registrants from issuing letters of credit or borrowing under the Master Credit Facility. The Duke Energy Registrants must meet credit quality standards and there is no assurance they will maintain investment grade credit ratings. If the Duke Energy Registrants are unable to maintain investment grade credit ratings, they would be required under credit agreements to provide collateral in the form of letters of credit or cash, which may materially adversely affect their liquidity. Each of the Duke Energy Registrants senior long-term debt issuances is currently rated investment grade by various rating agencies. The Duke Energy Registrants cannot ensure their senior long-term debt will be rated investment grade in the future. If the rating agencies were to rate the Duke Energy Registrants below investment grade, borrowing costs would increase, perhaps significantly. In addition, the potential pool of investors and funding sources would likely decrease. Further, if the short-term debt rating were to fall, access to the commercial paper market could be significantly limited. A downgrade below investment grade could also require the posting of additional collateral in the form of letters of credit or cash under various credit, commodity and capacity agreements and trigger termination clauses in some interest rate derivative agreements, which would require cash payments. All of these events would likely reduce the Duke Energy Registrants liquidity and profitability and could have a material effect on their results of operations, financial position and cash flows. Non-compliance with debt covenants or conditions could adversely affect the Duke Energy Registrants ability to execute future borrowings. The Duke Energy Registrants debt and credit agreements contain various financial and other covenants. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. ##TABLE_START RISK FACTORS ##TABLE_ENDMarket performance and other changes may decrease the value of the NDTF investments of Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida, which then could require significant additional funding. Ownership and operation of nuclear generation facilities also requires the maintenance of funded trusts that are intended to pay for the decommissioning costs of the respective nuclear power plants. The performance of the capital markets affects the values of the assets held in trust to satisfy these future obligations. Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida have significant obligations in this area and hold significant assets in these trusts. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below projected rates of return. Although a number of factors impact funding requirements, a decline in the market value of the assets may increase the funding requirements of the obligations for decommissioning nuclear plants. If Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida are unable to successfully manage their NDTF assets, their results of operations, financial position and cash flows could be negatively affected. Poor investment performance of the Duke Energy pension plan holdings and other factors impacting pension plan costs could unfavorably impact the Duke Energy Registrants liquidity and results of operations. The costs of providing non-contributory defined benefit pension plans are dependent upon a number of factors, such as the rates of return on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plans, future government regulation and required or voluntary contributions made to the plans. The Subsidiary Registrants are allocated their proportionate share of the cost and obligations related to these plans. Without sustained growth in the pension investments over time to increase the value of plan assets and, depending upon the other factors impacting costs as listed above, Duke Energy could be required to fund its plans with significant amounts of cash. Such cash funding obligations, and the Subsidiary Registrants proportionate share of such cash funding obligations, could have a material adverse impact on the Duke Energy Registrants results of operations, financial position and cash flows. Duke Energy is a holding company and depends on the cash flows from its subsidiaries to meet its financial obligations. Because Duke Energy is a holding company with no operations or cash flows of its own, its ability to meet its financial obligations, including making interest and principal payments on outstanding indebtedness and to pay dividends on its common stock, is primarily dependent on the net income and cash flows of its subsidiaries and the ability of those subsidiaries to pay upstream dividends or to repay borrowed funds. Prior to funding Duke Energy, its subsidiaries have regulatory restrictions and financial obligations that must be satisfied. These subsidiaries are separate legal entities and have no obligation to provide Duke Energy with funds. In addition, Duke Energy may provide capital contributions or debt financing to its subsidiaries under certain circumstances, which would reduce the funds available to meet its financial obligations, including making interest and principal payments on outstanding indebtedness and to pay dividends on Duke Energys common stock. GENERAL RISKS The failure of Duke Energy information technology systems, or the failure to enhance existing information technology systems and implement new technology, could adversely affect the Duke Energy Registrants businesses. Duke Energys operations are dependent upon the proper functioning of its internal systems, including the information technology systems that support our underlying business processes. Any significant failure or malfunction of such information technology systems may result in disruptions of our operations. In the ordinary course of business, we rely on information technology systems, including the internet and third-party hosted services, to support a variety of business processes and activities and to store sensitive data, including (i) intellectual property, (ii) proprietary business information, (iii) personally identifiable information of our customers, employees, retirees and shareholders and (iv) data with respect to invoicing and the collection of payments, accounting, procurement, and supply chain activities. Our information technology systems are dependent upon global communications and cloud service providers, as well as their respective vendors, many of whom have at some point experienced significant system failures and outages in the past and may experience such failures and outages in the future. These providers systems are susceptible to cybersecurity and data breaches, outages from fire, floods, power loss, telecommunications failures, break-ins and similar events. Failure to prevent or mitigate data loss from system failures or outages could materially affect the results of operations, financial position and cash flows of the Duke Energy Registrants. In addition to maintaining our current information technology systems, Duke Energy believes the digital transformation of its business is key to driving internal efficiencies as well as providing additional capabilities to customers. Duke Energys information technology systems are critical to cost-effective, reliable daily operations and our ability to effectively serve our customers. We expect our customers to continue to demand more sophisticated technology-driven solutions and we must enhance or replace our information technology systems in response. This involves significant development and implementation costs to keep pace with changing technologies and customer demand. If we fail to successfully implement critical technology, or if it does not provide the anticipated benefits or meet customer demands, such failure could materially adversely affect our business strategy as well as impact the results of operations, financial position and cash flows of the Duke Energy Registrants. Potential terrorist activities, or military or other actions, could adversely affect the Duke Energy Registrants businesses. The continued threat of terrorism and the impact of retaliatory military and other action by the U.S. and its allies may lead to increased political, economic and financial market instability and volatility in prices for natural gas and oil, which may have material adverse effects in ways the Duke Energy Registrants cannot predict at this time. In addition, future acts of terrorism and possible reprisals as a consequence of action by the U.S. and its allies could be directed against companies operating in the U.S. Information technology systems, transportation systems for our fuel sources including natural gas pipelines, transmission and distribution and generation facilities such as nuclear plants could be potential targets of terrorist activities or harmful activities by individuals or groups that could have a material adverse effect on Duke Energy Registrants' businesses. In particular, the Duke Energy Registrants may experience increased capital and operating costs to implement increased security for their information technology systems, transmission and distribution and generation facilities, including nuclear power plants under the NRCs design basis threat requirements. These increased costs could include additional physical plant security and security personnel or additional capability following a terrorist incident. ##TABLE_START RISK FACTORS ##TABLE_ENDFailure to attract and retain an appropriately qualified workforce could unfavorably impact the Duke Energy Registrants results of operations. Certain events, such as an aging workforce, mismatch of skill set or complement to future needs, or unavailability of contract resources may lead to operating challenges and increased costs. The challenges include lack of resources, loss of knowledge base and the lengthy time required for skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, may increase. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to new employees, or future availability and cost of contract labor may adversely affect the ability to manage and operate the business, especially considering the workforce needs associated with nuclear generation facilities and new skills required to operate a modernized, technology-enabled power grid. If the Duke Energy Registrants are unable to successfully attract and retain an appropriately qualified workforce, their results of operations, financial position and cash flows could be negatively affected.

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Item 1. Business. Item 1A. Risk Factors. Item 2. Properties.

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BUSINESS RISK FACTORSRISKS RELATING TO EDISON INTERNATIONALEdison Internationals liquidity and ability to pay dividends depends on its ability to borrow funds, access to bank and capital markets, monetization of tax benefits held by Edison International, and SCEs ability to pay dividends and tax allocation payments to Edison International. Edison International is a holding company and, as such, it has no material operations of its own. Edison Internationals ability to meet its financial obligations, make investments, and to pay dividends on its common stock is primarily dependent on the earnings and cash flows of SCE and SCEs ability to make upstream distributions. If SCE does not make upstream distributions to Edison International and Edison International is unable to access the bank and capital markets on reasonable terms, Edison International may be unable to continue to pay dividends to its shareholders or meet its financial obligations.Prior to paying dividends to Edison International, SCE has financial and regulatory obligations that must be satisfied, including, among others, debt service and preference stock dividends. Further, SCE and Edison International cannot pay dividends if California law requirements for the declaration of dividends are not met. For information on CPUC and California law requirements related to the declaration of dividends, see Liquidity and Capital ResourcesSCESCE Dividends in the MDA. SCE may also owe tax-allocation payments to Edison International under applicable tax-allocation agreements.Edison Internationals ability to obtain financing, as well as its ability to refinance debt and make scheduled payments of principal and interest, are dependent on numerous factors, including its levels of indebtedness, maintenance of acceptable credit ratings, financial performance, liquidity and cash flow, and other market conditions. In addition, the factors affecting SCEs business will impact Edison Internationals ability to obtain financing. Edison Internationals inability to borrow funds from time to time could have a material effect on Edison Internationals liquidity and operations.See Risks Relating to Southern California Edison Company below for further discussion.RISKS RELATING TO SOUTHERN CALIFORNIA EDISON COMPANYRegulatory and Legislative RisksSCEs financial results depend upon its ability to recover its costs and to earn a reasonable rate of return on capital investments in a timely manner from its customers through regulated rates. SCEs ongoing financial results depend on its ability to recover its costs from its customers, including the costs of electricity purchased for its customers, through the rates it charges its customers as approved by the CPUC and FERC. SCEs financial results also depend on its ability to earn a reasonable return on capital, including long-term debt and equity. SCEs ability to recover its costs and earn a reasonable rate of return can be affected by many factors, including the time lag between when costs are incurred and when those costs are recovered in customers rates and differences between the forecast or authorized costs embedded in rates (which are set on a prospective basis) and the amount of actual costs incurred. The CPUC or the FERC may not allow SCE to recover costs on the basis that such costs were not reasonably or prudently incurred or for other reasons. Further, SCE may incur expenses before the relevant regulatory agency approves the recovery of such costs. For example, SCE has incurred, and expects to further incur, wildfire mitigation expenses and increased labor and material costs due to supply chain constraints and elevated levels of inflation before it is clear whether such costs will be recoverable from customers. Also, the CPUC may deny recovery of costs incurred by SCE, including uninsured wildfire-related costs, if the CPUC determines that SCE was not prudent. For further information on recovery of uninsured wildfire-related costs, including costs related to the 2017/2018 Wildfire/Mudslide Events, see BusinessSouthern California WildfiresRecovery of Wildfire-Related Costs and Management OverviewSouthern California Wildfires and Mudslides in the MDA. In addition, while SCE supports Californias environmental goals, it may be prevented from fully executing on its strategy to support such goals by regulatory delay or lack of approval of cost-recovery for the costs of such strategic actions and electrification programs from the relevant regulatory agencies.SCEs authorized return on investment is established by multiplying an authorized rate of return, determined by the CPUC in standalone cost of capital proceedings, by SCEs authorized CPUC rate base. SCEs CPUC-authorized cost of capital is subject to potential adjustment should interest rates move substantially in years between cost of capital proceedings. For further information on the cost of capital mechanism see Management OverviewCost of Capital Applications in the MDA.SCEs capital investment plan, increasing procurement of renewable power and energy storage, inflation, commodity price volatility, increasing self-generation, load departures to CCAs or Electric Service Providers, and increasing environmental regulations, among other things, collectively place continuing upward pressure on customer rates. If customer rates continue to increase, the CPUC may face greater pressure to approve lesser amounts in SCEs ratemaking or cost recovery proceedings. To relieve some of this upward rate pressure, the CPUC may authorize lower revenues or increase the period over which SCE is allowed to recover amounts, which could impact SCEs ability to timely recover its operating costs. For example, in track 3 of the 2021 GRC, while the CPUC authorized SCE to recover costs through electric rates over a 36-month period, SCE may not recover all of its interest expense incurred as a result of financing such costs because the CPUC has only authorized interest accruals on the balances at a short-term rate of interest. If SCE is unable to obtain a sufficient rate increase or modify its rate design to recover its costs and an adequate return on capital in rates in a timely manner, its financial condition and results of operations could be materially affected.SCE is subject to extensive regulation and the risk of adverse regulatory and legislative decisions, delays in regulatory or legislative decisions, and changes in applicable regulations or legislation. SCE operates in a highly regulated environment. SCEs business is subject to extensive federal, state and local energy, environmental and other laws and regulations. Among other things, the CPUC regulates SCEs retail rates and capital structure, and the FERC regulates SCEs wholesale rates and capital structure. The NRC regulates the decommissioning of San Onofre in addition to the local and state agencies that require permits. The construction, planning, siting and operation of SCEs power plants, energy storage projects, and transmission lines in California are also subject to regulation by the CPUC and other local, state and federal agencies.SCE must periodically apply for licenses and permits from these various regulatory authorities, including environmental regulatory authorities, and must abide by their respective rules, regulations and orders. Should SCE be unsuccessful in obtaining necessary licenses or permits or should these regulatory authorities initiate any investigations or enforcement actions or impose fines, penalties or disallowances on SCE, SCE may be prevented from executing its strategy and its business could be materially affected. The process of obtaining licenses and permits from regulatory authorities may be delayed or defeated by opponents and such delay or defeat could have a material effect on SCEs business.To the extent the Wildfire Insurance Fund and other provisions of AB 1054 do not effectively mitigate the significant risk faced by California investor-owned utilities related to liability for damages arising from catastrophic wildfires where utility facilities are a substantial cause, not achieving a more comprehensive solution could have a detrimental effect on SCEs business and financial condition. The effectiveness of AB 1054 to mitigate the wildfire-related risk faced by SCE is conditioned in part on the performance of OEIS and various entities formed under AB 1054 and related legislation to, among other things, administer the Wildfire Insurance Fund, approve WMPs, issue safety certifications, oversee and enforce compliance with wildfire safety standards, and develop metrics to reduce risk and measure compliance with risk reduction. In addition, CPUC approval is required to recover the costs SCE is incurring to strengthen its wildfire mitigation and prevention efforts described in SCEs WMPs. See BusinessSouthern California Wildfires and Liquidity and Capital ResourcesSCERegulatory ProceedingsWildfire Related Regulatory Proceedings in the MDA.In addition, existing regulations may be revised or re-interpreted and new laws and regulations may be adopted or become applicable to SCE, or its facilities or operations, in a manner that may have a detrimental effect on SCEs business or result in significant additional costs. In addition, regulations adopted via the public initiative or legislative process may apply to SCE, or its facilities or operations, in a manner that may have a detrimental effect on SCEs business or result in significant additional costs.SCEs energy procurement activities are subject to regulatory and market risks that could materially affect its financial condition and liquidity. SCE obtains energy, capacity, environmental credits and ancillary services needed to serve its customers from its own generating plants and through contracts with energy producers and sellers. California law and CPUC decisions allow SCE to recover, through the rates it is allowed to charge its customers, reasonable procurement costs incurred in compliance with an approved procurement plan. Nonetheless, SCEs cash flows remain subject to volatility primarily resulting from changes in commodity prices, including as a result of gas supply constraints. Additionally, significant and prolonged gas use restrictions may adversely impact the reliability of the electric grid if critical generation resources are limited in their operations. For further information, see BusinessSCEPurchased Power and Fuel Supply. SCE is also subject to the risks of unfavorable or untimely CPUC decisions about the compliance with SCEs procurement plan and the reasonableness of certain procurement-related costs.SCE may not be able to hedge its risk for commodities on economic terms or fully recover the costs of hedges through the rates it is allowed to charge its customers, which could materially affect SCEs liquidity and results of operations, see Market Risk Exposures in the MDA.Operating RisksDamage claims against SCE for wildfire-related losses may materially affect SCEs financial condition and results of operations. Prolonged drought conditions and shifting weather patterns in California resulting from climate change as well as, among other things, buildup of dry vegetation in areas severely impacted by years of historic drought and lack of adequate clearing of hazardous fuels by responsible parties have increased the duration of the wildfire season and the risk of severe wildfire events.Severe wildfires and increased urban development in high fire risk areas in California have given rise to large damage claims against California utilities for fire-related losses alleged to be the result of utility practices and/or the failure of electric and other utility equipment. Catastrophic wildfires can occur in SCEs service territory even if SCE effectively implements its WMPs. California courts have previously found utilities to be strictly liable for property damage, regardless of fault, by applying the theory of inverse condemnation when a utilitys facilities were determined to be a substantial cause of a wildfire that caused the property damage. The rationale generally stated by these courts for applying this theory to investor-owned utilities is that property losses resulting from a public improvement, such as the distribution of electricity, can be spread across the larger community that benefited from such improvement. However, in November 2017, the CPUC issued a decision denying an investor-owned utilitys request to include in its rates uninsured wildfire-related costs arising from several 2007 fires, finding that the investor-owned utility did not prudently manage and operate its facilities prior to or at the outset of the 2007 wildfires. An inability to recover uninsured wildfire-related costs could materially affect SCEs business, financial condition and results of operations. For example, if SCE is unable to, or believes that it may be unable to, recover damages related to catastrophic wildfires through insurance, the Wildfire Insurance Fund (which is only available for fires ignited after July 12, 2019) or electric rates, or access the bank and capital markets on reasonable terms, SCE may not have sufficient cash or equity to pay dividends or may be restricted from declaring such dividends because it does not meet CPUC or California law requirements related to the declaration of dividends. For information on the California law requirements on the declaration of dividends, see Liquidity and Capital ResourcesSCESCE Dividends in the MDA. Also see Notes to Consolidated Financial StatementsNote 12. Commitments and ContingenciesContingenciesSouthern California Wildfires and Mudslides.Edison Internationals and SCEs costs of accessing capital markets has increased due to the risks associated with wildfires in Southern California. Edison Internationals and SCEs access to the bank and capital markets could also be constrained and/or the costs of accessing those markets could increase further as a result of wildfire risk, including if Edison Internationals and/or SCEs credit ratings are downgraded or placed on negative watch due to concerns about Edison International and/or SCEs financial health as a result of wildfires.SCEs insurance coverage for wildfires may not be sufficient. Edison International has experienced increased costs and difficulties in obtaining insurance coverage for wildfires that could arise in connection with SCEs ordinary operations. Edison International, SCE and its contractors may experience coverage reductions and/or increased wildfire insurance costs in future years. No assurance can be given that losses will not exceed the limits of SCEs or its contractors insurance coverage. SCE may not be able to recover uninsured losses (including amounts paid for self-insured retention and co-insurance) and increases in the cost of insurance in electric rates. Losses which are not fully insured or cannot be recovered through the Wildfire Insurance Fund or electric rates could materially affect Edison Internationals and SCEs financial condition and results of operations. For more information on wildfire insurance risk, see Notes to Consolidated Financial StatementsNote 12. Commitments and ContingenciesContingenciesSouthern California Wildfires and Mudslides.SCE may not effectively implement its wildfire mitigation plans.SCE will face a higher likelihood of catastrophic wildfires in its service territory if it cannot effectively implement its WMPs. For example, SCE may not be able to effectively implement its WMPs if it experiences unanticipated difficulties relative to sourcing, engaging, and retaining effectively trained contract workers or procuring materials it needs to fulfill its mitigation obligations under the WMPs. In addition, if SCE does not have an approved WMP, SCE will not be issued a safety certification from the CPUC and will consequently not benefit from the presumption of prudency or the AB 1054 Liability Cap.The CPUC may assess penalties on SCE if it finds that SCE has failed to substantially comply with its WMP. In addition, SCE may be subject to mandated changes to, or restrictions on, its operational wildfire mitigation practices or be subject to regulatory fines and penalties or claims for damages and reputational harm if SCE does not execute its wildfire mitigation practices in compliance with applicable rules and regulations. SCEs wildfire mitigation practices include PSPS and using fast-curve settings. In addition, SCE may be subject to regulatory fines and penalties or claims for damages and reputational harm if it is determined that SCE has placed excessive or unreasonable reliance on PSPS.SCE establishes the criteria under which it implements PSPS in its territory. To the extent SCEs criteria for implementing PSPS are not sufficient to mitigate the risk of wildfires during high wind events, SCE does not fully implement PSPS when criteria are met due to other overriding conditions or SCEs regulators or others mandate changes to, or restrictions on, its criteria or other operational PSPS practices, SCE will face a higher likelihood of catastrophic wildfires in its territory during high wind events. Similarly, if SCE is prohibited from implementing its desired fast-curve settings, SCE will face a higher likelihood of catastrophic wildfires in its territory.For more information on AB 1054, see BusinessSouthern California WildfiresRecovery of Wildfire-Related Costs2019 Wildfire Legislation.SCE will not benefit from all of the features of AB 1054 if the Wildfire Insurance Fund is exhausted. Catastrophic wildfires could rapidly exhaust the Wildfire Insurance Fund and SCE will not be reimbursed by the Wildfire Insurance Fund or benefit from the AB 1054 Liability Cap if the fund has been exhausted as a result of damage claims previously incurred by SCE or the other participating utilities.For more information on AB 1054, see BusinessSouthern California Wildfires and MudslidesRecovery of Wildfire-Related Costs2019 Wildfire Legislation.Climate change exacerbated weather-related incidents and other natural disasters could materially affect SCEs financial condition and results of operations. Weather-related incidents, including storms and events caused, or exacerbated, by climate change, such as wildfires, flooding and debris flows, and other natural disasters such as earthquakes can disrupt the generation and transmission of electricity, and can seriously damage the infrastructure necessary to deliver power to SCEs customers. The impacts of climate change continue to evolve and remain dynamic and unpredictable. Climate change has caused, and exacerbated, extreme weather events and wildfires in southern California, and wildfires could cause, among other things, public safety issues, property damage and operational issues. In addition, the risk of flooding and debris flows occurring as a result of rain may be heightened. For example, the 2017/2018 Wildfire/Mudslide Events resulted in, among other things, loss of life, property damage and loss of service. For more information on the impact of the 2017/2018 Wildfire/Mudslide Events on SCE and Edison International, see Notes to Consolidated Financial StatementsNote 12. Commitments and ContingenciesContingenciesSouthern California Wildfires and

Mudslides.Extreme heat events can lead to prolonged widespread outages due to, among other things, state-wide capacity supply shortages or equipment failure. Extreme weather events can also lead to use of PSPS. Weather-related events, such as debris flows, flooding and melting of a significantly higher than normal snowpack, and earthquakes can cause over-topping or failure at an SCE dam resulting in a rapid release of water that could cause, among other things, public safety issues, property damage and operational issues.Weather-related incidents and other natural disasters can lead to lost revenue and increased expense, including higher maintenance and repair costs, which SCE may not be able to recover from its customers. These incidents can also result in regulatory penalties and disallowances, particularly if SCE encounters difficulties in restoring power to its customers on a timely basis or if fire-related losses are found to be the result of utility practices and/or the failure of electric and other utility equipment. In addition, these occurrences could lead to significant claims for damages, including for loss of life and property damage. These occurrences could materially affect SCEs business, financial condition and results of operations, and the inability to restore power to SCEs customers could also materially damage the business reputation of SCE and Edison International.For additional information related to climate related risks, see BusinessEnvironmental ConsiderationsEnvironmental Risks.The generation, transmission and distribution of electricity are dangerous and involve inherent risks of damage to private property and injury to SCEs workforce and the general public. Electricity poses hazards for SCEs workforce and the general public should they come in contact with electrical current or equipment, including through energized downed power lines or if equipment malfunctions. In addition, the risks associated with the operation of transmission and distribution assets and power generation and storage facilities include public and workforce safety issues and the risk of utility assets causing or contributing to wildfires.Injuries and property damage caused by such events can subject SCE to liability that, despite the existence of insurance coverage, can be significant. In addition, SCE may be held responsible for the actions of its contractors. No assurance can be given that future losses will not exceed the limits of SCEs or its contractors insurance coverage. The CPUC has increased its focus on public safety with an emphasis on heightened compliance with construction and operating standards and the potential for penalties being imposed on utilities. Additionally, the CPUC has delegated to its staff the authority to issue citations to electric utilities, which can impose fines of up to $100,000 per violation per day (capped at a maximum of $8 million), pursuant to the CPUCs jurisdiction for violations of safety rules found in statutes, regulations, and the CPUCs General Orders. The CPUC also can issue fines greater than $8 million outside of the citation program. Such penalties and liabilities could be significant and materially affect SCEs liquidity and results of operations. SCEs financial condition and results of operations could be materially affected if it is unable to successfully manage the risks inherent in constructing, operating, and maintaining its facilities and workforce. SCEs infrastructure is aging and could pose a risk to system reliability. SCE is also constructing utility owned storage to mitigate possible state-wide capacity shortages in 2023 and later years, and any delays in construction may result in those facilities being unavailable to reduce the impact of any capacity shortages in summer 2023. In addition, as described above, wildfires in SCEs service territory can cause significant public safety issues, property damage and operational issues. In order to mitigate these risks, SCE is engaged in a significant and ongoing infrastructure investment program. This substantial investment program has inherent operational risks and elevates the need for superior execution in SCEs activities. SCEs financial condition and results of operations could be materially affected if it is unable to successfully manage these risks as well as the risks inherent in constructing, operating, and maintaining its facilities, the operation of which can be hazardous and important for system reliability. SCEs inherent operating risks include such matters as the risks of human performance, workforce capabilities, contractor management, data and records accuracy, public opposition to infrastructure projects, delays, environmental remediation and mitigation costs, difficulty in estimating costs or in recovering costs that are above original estimates, system limitations and degradation, maintaining physical security of workforce and assets, maintaining cybersecurity of data and assets, and delays and interruptions in necessary supplies, including key components necessary for the timely construction of utility owned storage. For example, SCEs financial condition may be materially affected as a result of safety incidents, delays, permitting violations and violations of regulatory requirements, among other things, caused by SCEs failure to appropriately manage its contractor workforce or from contractual violations by SCEs contractors and the inability for SCE to recover through contractual indemnities or insurance held by the contractor. SCEs financial condition may also be materially affected as a result of data or records inaccuracies, for example inaccurate records could lead to missing or delayed compliance with SCEs policies and regulatory requirements, and could contribute to safety incidents. SCEs financial condition and results of operations could also be materially affected if SCE is unable to attract, train and retain a qualified and diverse workforce, including due to the constrained labor market in California and nationally and SCEs relations with its unionized workforce. SCEs financial condition and results of operations could also be materially affected as a result of atypical resolutions to litigation proceedings arising from its operations, including atypical settlements and verdicts. For instance, SCE was subject to an atypical jury verdict in a recent employment litigation matter. There are inherent risks associated with owning and decommissioning nuclear power generation facilities and obtaining cost reimbursement, including, among other things, insufficiency of nuclear decommissioning trust funds, costs exceeding current estimates, execution risks, potential harmful effects on the environment and human health and the hazards of storage, handling and disposal of radioactive materials. Existing insurance and ratemaking arrangements may not protect SCE fully against losses from a nuclear incident. SCE funds decommissioning costs with assets that are currently held in nuclear decommissioning trusts. Based upon the financial performance of the nuclear decommissioning trust fund investments, as well as the resolution of a number of other uncertainties, assumptions and estimates, additional contributions to the nuclear decommissioning trusts funds may be required. If additional contributions to the nuclear decommissioning trust funds become necessary, recovery of any such additional funds through electric rates is subject to the CPUCs review and approval.The costs of decommissioning San Onofre are subject to reasonableness reviews by the CPUC. These costs may not be recoverable through regulatory processes or otherwise unless SCE can establish that the costs were reasonably incurred. In addition, SCE faces inherent execution risks including such matters as the risks of human performance, workforce capabilities, public opposition, permitting delays, and governmental approvals. Decommissioning costs ultimately incurred could exceed the current estimates and cost increases resulting from contractual disputes, delays in performance by the contractor, elevated levels of inflation, or permitting delays, among other things, could cause SCE to materially overrun current decommissioning cost estimates and could materially impact the sufficiency of trust funds. See Liquidity and Capital ResourcesSCEDecommissioning of San Onofre in the MDA.Even though San Onofre is being decommissioned, the presence of spent nuclear fuel still poses a potential risk of a nuclear incident. Federal law limits public liability claims from a nuclear incident to the amount of available financial protection, which is currently approximately $13.7 billion for Palo Verde and $560 million for San Onofre. SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available of $450 million per site. In the case of San Onofre, the balance is covered by a US Government indemnity. In the case of Palo Verde, the balance is covered by a loss sharing program among nuclear reactor licensees. There is no assurance that the CPUC would allow SCE to recover the required contribution made pursuant to this loss sharing program in the case of one or more nuclear incidents with claims that exceeded $450 million at a nuclear reactor which is participating in the program. If this public liability limit of $13.7 billion is insufficient, federal law contemplates that additional funds may be appropriated by Congress. There can be no assurance of SCEs ability to recover uninsured costs in the event the additional federal appropriations are insufficient. For more information on nuclear insurance risk, see Notes to Consolidated Financial StatementsNote 12. Commitments and ContingenciesContingenciesNuclear Insurance.SCEs distribution of water and propane gas on Catalina Island involves inherent risks of damage to private property and the environment and injury to employees and the general public. SCE owns and operates the water distribution system that serves Catalina Island, California and a propane gas distribution system that serves the City of Avalon on Catalina Island, California. Production, storage, treatment and distribution of water for human use and the transportation, storage, distribution and use of gas can be hazardous, and can cause damage to private property and the environment and injury to employees and the general public if equipment fails or does not perform as anticipated. For example, the risks of operating a water distribution system include the potential for burst pipes and water contamination and the risks of operating gas distribution system include the potential for gas leaks, fire or explosion. The risks related to SCEs operation of its water and gas distribution systems may be exacerbated due to aging infrastructure. SCE has requested that the CPUC allow SCE to include certain water system costs in electric rates and may make similar requests for the water and gas systems in the future. If such requests are denied, significant costs may not be recoverable from customers. In addition, SCE may have to pay fines, penalties and remediation costs if it does not comply with laws and regulations in the operation of the water and gas distribution systems. An inability to recover costs associated with any such damages or injuries or any fines, penalties or remediation costs, from insurance or through electric rates, could materially affect SCEs business, financial condition and results of operations.Financing RisksAs a capital-intensive company, SCE relies on access to the capital markets. If SCE were unable to access the capital markets or the cost of financing were to substantially increase, its liquidity and operations could be materially affected. SCE regularly accesses the capital markets to finance its activities and is expected to do so by its regulators as part of its obligation to serve as a regulated utility. SCEs needs for capital for its ongoing infrastructure investment program are substantial. SCEs ability to obtain financing, as well as its ability to refinance debt and make scheduled payments of principal and interest, are dependent on numerous factors, including SCEs levels of indebtedness, maintenance of acceptable credit ratings, financial performance, liquidity and cash flow, and other market conditions. In addition, the actions of other California investor-owned utilities and legal, regulatory and legislative decisions impacting investor-owned utilities can affect market conditions and therefore, SCEs ability to obtain financing. SCEs inability to obtain additional capital from time to time could have a material effect on SCEs liquidity and operations.Competitive and Market RisksSCEs inability to effectively and timely respond to the changes that the electricity industry is undergoing, as a result of increased competition, technological advances, and changes to the regulatory environment, could materially impact SCEs business model, financial condition and results of operations. Customers and third parties are increasingly deploying distributed energy resources (DERs), such as solar generation, energy storage, energy efficiency and demand response technologies. Californias environmental policy objectives are accelerating the pace and scope of industry change. This change will require modernization of the electric distribution grid to, among other things, accommodate two-way flows of electricity and increase the grids capacity to interconnect DERs. In addition, enabling Californias clean energy economy goals will require sustained investments in grid modernization, renewable integration projects, energy efficiency programs, energy storage options and electric vehicle infrastructure. If SCE is unable to effectively adapt to these changes, its business model, its ability to execute on its strategy, and ultimately its financial condition and results of operations could be materially impacted.Customer-owned generation and load departures to CCAs or Electric Service Providers each reduce the amount of electricity that customers purchase from utilities and have the effect of increasing utility rates unless customer rates are designed to allocate the costs of the distribution grid across all customers that benefit from its use. For example, some customers in California who generate their own power are not currently required to pay all transmission and distribution charges and non-bypassable charges, subject to limitations, which results in increased costs for those customers who do not own their generation. If regulations arent changed such that customers pay their share of transmission and distribution costs and non-bypassable charges and the demand for electricity reduces so significantly that SCE is no longer effectively able to recover such costs from its customers, SCEs business, financial condition and results of operations will be materially impacted.In addition, the FERC has opened transmission development to competition from independent developers, allowing such developers to compete with incumbent utilities for the construction and operation of transmission facilities.For more information. See BusinessSCECompetition.Cybersecurity and Physical Security RisksSCEs systems and network infrastructure are targets for physical and cyber attacks, intrusions or other catastrophic events that could result in their failure or reduced functionality. Regulators such as NERC and U.S. Government agencies, including the Departments of Defense, Homeland Security and Energy, have increasingly stressed that threat sources continue to seek to exploit potential vulnerabilities in the U.S. national electric grid and other energy infrastructures, and that such attacks and disruptions, both physical and cyber, are highly sophisticated and dynamic. Several U.S. Government agencies have highlighted the increasing risks related to physical attacks, ransomware attacks and cybersecurity risks related to the electric sector, including its supply chains, and that the risks may escalate during periods of heightened geopolitical tensions. SCEs operations require the continuous availability of critical information technology systems, sensitive customer and employee data and network infrastructure and information, all of which are targets for malicious actors. New cyber and physical threats arise as SCE moves from an analog to a digital electric grid. For example, SCEs grid modernization efforts and the move to a network-connected grid increases the number of threat surfaces and potential vulnerabilities that an adversary can target. SCE system data and architecture are also disclosed, either intentionally or unintentionally, to third parties and the public by regulators, employees, contractors and vendors. This system information may be used by malicious actors to understand SCEs systems to prepare for a cyber or physical attack.SCE depends on a wide array of vendors to provide it with services and equipment. Malicious actors may attack vendors to disrupt the services they provide to SCE, or to use those vendors as a conduit to attack SCE. Additionally, the equipment and material provided by SCEs vendors may contain cyber vulnerabilities. A compromise of equipment and/or exfiltration of SCE data, whether by physical or by electronic means, could result in loss or changes to confidential or sensitive electronic data, loss of intellectual property and interruption of business processes. While some of SCEs vendors have experienced cybersecurity incidents, such incidents have not, to SCEs knowledge, resulted in a material impact to SCE to date.SCEs systems have experienced, and will continue to experience, cybersecurity incidents involving attacks of malicious code, unauthorized access attempts, and other illicit activities, but to SCEs knowledge it has not experienced a material cybersecurity or data breach to date. Though SCE actively monitors developments in this area, no security measures can completely shield its systems, infrastructure and data from cyber attacks, intrusions or other catastrophic events that could result in their failure or reduced functionality.If SCEs information technology and operational technology systems security measures were to be breached, or a critical system failure were to occur without timely recovery, SCE could be unable to fulfill critical business functions, such as delivery of electricity to customers, and/or sensitive confidential personal and other data could be compromised, which could result in violations of applicable privacy and other laws, material financial loss to SCE or to its customers, loss of confidence in SCEs security measures, customer dissatisfaction, and significant litigation and/or regulatory exposure, all of which could materially affect SCEs financial condition and results of operations and materially damage the business reputation of Edison International and SCE.RISKS RELATING TO EDISON INTERNATIONAL AND SOUTHERN CALIFORNIA EDISON COMPANY Edison Internationals and SCEs financial condition and results of operations could be materially impacted by events, like the COVID-19 pandemic, that cause significant disruption to workforces, supply chains, economies, or societies on a regional, statewide, national or global basis. Edison International and SCE could be materially and adversely impacted by events, such as the widespread outbreak of a communicable disease, that result in, among other things, significant disruption to supply chains, economies, societies or workforces on a regional, statewide, national or global basis. For example, the global spread of COVID-19, which was declared a pandemic by the World Health Organization in March 2020, created significant uncertainty, volatility and disruption globally and has impacted the operations of Edison International and SCE. Many of the risks and uncertainties identified in this Form 10-K are, and will be, exacerbated by the impacts of an event like a pandemic and the actions being taken by governmental entities, businesses, individuals and others in response to such an event. For example, SCE may be unable to effectively execute its PSPS program due to, among other things, requests from local and State authorities not to shut off the power during a pandemic or other event, and thereby may increase the risk of SCE equipment being associated with the ignition of wildfires.In addition, impacts of a pandemic or similar event on SCEs customers and third parties could also result in SCE facing, among other things, significant reductions in demand for electricity and payment delays and/or defaults from customers which could result in significant under-collections. In addition, Edison International and SCE could also face payment delays and/or defaults from insurers and other counterparties. Furthermore, Edison Internationals and SCEs access to the bank and capital markets could also be constrained and/or the costs of accessing those markets could increase as a result of a pandemic or similar event, including if Edison Internationals and/or SCEs credit ratings are downgraded, or placed on negative watch due to concerns about Edison International and/or SCEs financial health as a result of the impacts of the pandemic. SCE may also incur significant incremental costs as a result of actions it is taking in response to a pandemic or a similar event, including costs being incurred to maintain its operations and assist its employees who are required to telework or are otherwise impacted by the event. SCE could also face delays in important legal and regulatory proceedings. These impacts, among others, could materially and adversely impact Edison Internationals and SCEs business, operations, cash flows, liquidity and financial results.Edison Internationals and SCEs business activities are concentrated in one industry and in one region.Edison Internationals and SCEs business activities are concentrated in the electric utility industry. Edison Internationals principal subsidiary, SCE, serves customers only in southern and central California. As a result, Edison Internationals and SCEs future performance may be affected by events and economic factors unique to California or by regional regulation, legislation or judicial decisions. For example, California courts have applied strict liability to investor-owned utilities in wildfire and other litigation matters. See Notes to Consolidated Financial StatementsNote 12. Commitments and ContingenciesContingenciesSouthern California Wildfires and Mudslides.

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Item 1. Business RISK FACTORS SUMMARY Entergys business is subject to numerous risks and uncertainties that could affect its ability to successfully implement its business strategy and affect its financial results. Carefully consider all of the information in this report and, in particular, the following principal risks and all of the other specific factors described in Item 1A. of this report, Risk Factors, before deciding whether to invest in Entergy or the Registrant Subsidiaries. Utility Regulatory Risks The terms and conditions of service, including electric and gas rates, of the Utility operating companies and System Energy are determined through regulatory approval proceedings that can be lengthy and subject to appeal, potentially resulting in lengthy litigation, and uncertainty as to ultimate results. Entergys business could experience adverse effects related to changes to state or federal legislation or regulation. The Utility operating companies recover fuel, purchased power, and associated costs through rate mechanisms that are subject to risks of delay or disallowance in regulatory proceedings. The Utility operating companies are subject to risks associated with participation in the MISO markets and the allocation of transmission upgrade costs. The continued impacts of the COVID-19 pandemic and responsive measures taken are highly uncertain and cannot be predicted. A delay or failure in recovering amounts for storm restoration costs incurred as a result of severe weather could have material effects on Entergy and its Utility operating companies affected by severe weather. Weather, economic conditions, technological developments, and other factors may have a material impact on electricity and gas usage and otherwise materially affect the Utility operating companies results of operations. Nuclear Operating, Shutdown, and Regulatory Risks The results of operations, financial condition, and liquidity of Entergy Arkansas, Entergy Louisiana, and System Energy could be materially affected by the following: inability to consistently operate their nuclear power plants at high capacity factors; refueling outages that last materially longer than anticipated or unplanned outages; risks related to the purchase of uranium fuel (and its conversion, enrichment, and fabrication); the risk that the NRC will change or modify its regulations, suspend or revoke their licenses, or increase oversight of their nuclear plants; risks and costs related to operating and maintaining their nuclear power plants; the costs associated with the storage of the spent nuclear fuel, as well as the costs of and their ability to fully decommission their nuclear power plants; the potential requirement to pay substantial retrospective premiums imposed under the Price-Anderson Act and/or by Nuclear Electric Insurance Limited (NEIL) in the event of a nuclear incident, and losses not covered by insurance; the risk that the decommissioning trust fund assets for the nuclear power plants may not be adequate to meet decommissioning obligations if market performance and other changes decrease the value of assets in the decommissioning trusts; and new or existing safety concerns regarding operating nuclear power plants and nuclear fuel. General Business Risks Entergy and the Registrant Subsidiaries depend on access to the capital markets and, at times, may face potential liquidity constraints, which could make it more difficult to handle future contingencies. Disruptions in the capital and credit markets may adversely affect Entergys and its subsidiaries ability to meet liquidity needs, access capital and operate and grow their businesses, and the cost of capital. Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy A downgrade in Entergys or its Registrant Subsidiaries credit ratings could, among other things, negatively affect Entergys and its Registrant Subsidiaries ability to access capital and the cost of such capital. Entergy or its Registrant Subsidiaries may be materially adversely affected by negative publicity or the inability to meet their stated goals or commitments, among other potential causes. Changes in tax legislation and taxation as well as the inherent difficulty in quantifying potential tax effects of business decisions could negatively impact Entergys and the Registrant Subsidiaries results of operations, financial condition, and liquidity. Entergy and its subsidiaries ability to successfully execute on their business strategies, including their ability to complete capital projects, other capital improvements, and strategic transactions, is subject to significant risks, and, as a result, they may be unable to achieve some or all of the anticipated results of such strategies. Failure to attract, retain, and manage an appropriately qualified workforce could negatively affect Entergy or its subsidiaries results of operations. Entergy and Entergys subsidiaries, including the Utility operating companies and System Energy, may incur substantial costs (i) to fulfill their obligations related to environmental and other matters or (ii) related to reliability standards. Entergy could be negatively affected by the effects of climate change, including physical risks, such as increased frequency and intensity of hurricanes and other severe weather, and transition risks, such as environmental and regulatory obligations intended to combat the effects of climate change, including by compelling greenhouse gas emission reductions or reporting, or increasing clean or renewable energy requirements, or placing a price on greenhouse gas emissions. Entergy and its subsidiaries are dependent on the continued and future availability and quality of water for cooling, process, and sanitary uses. Entergy and its subsidiaries may not be adequately hedged against changes in commodity prices. The Utility operating companies and Entergys non-regulated operations are exposed to the risk that counterparties may not meet their obligations. Market performance and other changes may decrease the value of benefit plan assets, which then could require additional funding and result in increased benefit plan costs. The litigation environment in the states in which the Registrant Subsidiaries operate poses a significant risk to those businesses. Terrorist attacks, physical attacks, cyber attacks, system failures, or data breaches of Entergys and its subsidiaries or their suppliers physical infrastructure or technology systems may adversely affect Entergys results of operations. Entergy and the Registrant Subsidiaries are subject to risks associated with their ability to obtain adequate insurance at acceptable costs. Significant increases in commodity prices, other materials and supplies, and operation and maintenance expenses may adversely affect Entergys results of operations, financial condition, and liquidity. The effect of higher purchased gas cost charges to customers taking gas service may adversely affect Entergy New Orleanss results of operations and liquidity. System Energy owns and, through an affiliate, operates a single nuclear generating facility, and it is dependent on sales to affiliated companies for all of its revenues. Certain contractual arrangements relating to System Energy, the affiliated companies, and these revenues are the subject of ongoing litigation and regulatory proceedings. The aggregate amount of refunds claimed in these proceedings substantially exceeds the current net book value of System Energy. In the event of an adverse decision in one or more of these proceedings requiring the payment of substantial additional refunds, System Energy would be required to seek financing to pay such refunds, which financing may not be available on terms acceptable to System Energy, or may not be available at all, when required. If one or more of the foregoing events occurs, System Energy may be required to explore other options or protections available to it to extend, restructure, or retire its indebtedness and to prioritize its obligations. Entergys non-regulated operations are subject to substantial governmental regulation and may be adversely affected by legislative, regulatory, or market design changes, as well as liability under, or any future inability to comply with, existing or future regulations or requirements. As a holding company, Entergy Corporation depends on cash distributions from its subsidiaries to meet its debt service and other financial obligations and to pay dividends on its common stock, and has provided, and may continue to provide, capital contributions or debt financing to its subsidiaries, which would reduce the funds available to meet its other financial obligations. Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy ENTERGYS BUSINESS Entergy is an integrated energy company engaged primarily in electric power production and retail distribution operations. Entergy owns and operates power plants with approximately 24,000 MW of electric generating capacity, including approximately 5,000 MW of nuclear power. Entergy delivers electricity to 3 million utility customers in Arkansas, Louisiana, Mississippi, and Texas. Entergy had annual revenues of $13.8 billion in 2022 and had approximately 12,000 employees as of December 31, 2022. Entergy operates primarily through two business segments: Utility and Entergy Wholesale Commodities. The Utility business segment includes the generation, transmission, distribution, and sale of electric power in portions of Arkansas, Mississippi, Texas, and Louisiana, including the City of New Orleans; and operation of a small natural gas distribution business. The Entergy Wholesale Commodities business segment includes the ownership, operation, and decommissioning of nuclear power plants located in the northern United States and the sale of the electric power produced by its operating plants to wholesale customers. Entergy Wholesale Commodities also provides services to other nuclear power plant owners and owns interests in non-nuclear power plants that sell the electric power produced by those plants to wholesale customers. See MANAGEMENTS FINANCIAL DISCUSSION AND ANALYSIS - Entergy Wholesale Commodities Exit from the Merchant Power Business for discussion of the shutdown and sale of each of the Entergy Wholesale Commodities nuclear power plants. With the sale of Palisades in June 2022, Entergy completed its multi-year strategy to exit the merchant nuclear power business. Upon completion of all transition activities, effective January 1, 2023, Entergy Wholesale Commodities is no longer a reportable business segment. See Note 13 to the financial statements for financial information regarding Entergys business segments. Strategy Entergys strategy is to operate and grow its utility business, creating sustainable value for its customers, employees, communities, and owners. Entergys strategy to achieve its stakeholder objectives has a few key aspects. First, Entergy invests in the Utility for the benefit of its customers, which supports steady, predictable growth in earnings and dividends. Second, Entergy manages risks by ensuring its Utility investments are customer-centric, supported by progressive regulatory constructs, and executed with disciplined project management. Third, Entergy is committed to delivering sustainable outcomes for all of its stakeholders by focusing on continually improving key elements of Environmental, Social, and Governance (ESG), including reducing carbon emissions and improving resilience for Entergy and its customers. Entergy also executed the wind down of the Entergy Wholesale Commodities merchant nuclear generation business, which was effectively complete by the end of 2022. Utility The Utility business segment includes five retail electric utility subsidiaries: Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, and Entergy Texas. These companies generate, transmit, distribute, and sell electric power to retail and wholesale customers in Arkansas, Louisiana, Mississippi, and Texas. Entergy Louisiana and Entergy New

Orleans also provide natural gas utility services to customers in and around Baton Rouge, Louisiana, and New Orleans, Louisiana, respectively. Also included in the Utility is System Energy, a wholly-owned subsidiary of Entergy Corporation that owns or leases 90 percent of Grand Gulf. System Energy sells its power and capacity from Grand Gulf at wholesale to Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans. The five retail utility subsidiaries are each regulated by the FERC and by state utility commissions, or, in the case of Entergy New Orleans, the City Council. System Energy is regulated by the FERC because all of its transactions are at wholesale. The Utility has a diverse power generation portfolio, including increasingly carbon-free energy sources, which is consistent with Entergys strong support for the environment. Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy Customers As of December 31, 2022, the Utility operating companies provided retail electric and gas service to customers in Arkansas, Louisiana, Mississippi, and Texas, as follows: ##TABLE_START Electric Customers Gas Customers Area Served (In Thousands) (%) (In Thousands) (%) Entergy Arkansas Portions of Arkansas 730 24 % Entergy Louisiana Portions of Louisiana 1,101 37 % 95 47 % Entergy Mississippi Portions of Mississippi 461 15 % Entergy New Orleans City of New Orleans 211 7 % 109 53 % Entergy Texas Portions of Texas 499 17 % Total customers 3,002 100 % 204 100 % ##TABLE_ENDElectric and Natural Gas Energy Sales Electric Energy Sales The total electric energy sales of the Utility operating companies are subject to seasonal fluctuations, with the peak sales period normally occurring during the third quarter of each year. On June 24, 2022, Entergy reached a 2022 peak demand of 22,301 MWh, compared to the 2021 peak of 22,051 MWh recorded on August 23, 2021. Selected electric energy sales data for 2022 is shown in the table below: ##TABLE_START Entergy Arkansas Entergy Louisiana Entergy Mississippi Entergy New Orleans Entergy Texas System Energy Entergy (a) (GWh) Sales to retail customers 22,473 57,532 13,038 5,706 21,380 120,129 Sales for resale: Affiliates 1,906 5,416 279 7,739 Others 6,520 3,423 2,914 2,298 813 15,968 Total 30,899 66,371 15,952 8,004 22,472 7,739 136,097 Average use per residential customer (kWh) 13,478 14,874 14,791 12,818 15,444 14,479 ##TABLE_END(a) Includes the effect of intercompany eliminations. The following table illustrates the Utility operating companies 2022 combined electric sales volume as a percentage of total electric sales volume, and 2022 combined electric revenues as a percentage of total 2022 electric revenue, each by customer class. ##TABLE_START Customer Class % of Sales Volume % of Revenue Residential 27.3 35.2 Commercial 20.6 23.4 Industrial (a) 38.6 28.2 Governmental 1.8 2.2 Wholesale/Other 11.7 11.0 ##TABLE_END(a) Major industrial customers are primarily in the petroleum refining and chemical industries. Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy Natural Gas Energy Sales Entergy New Orleans and Entergy Louisiana provide both electric power and natural gas to retail customers. Entergy New Orleans and Entergy Louisiana sold 10,514,012 and 6,786,779 Mcf, respectively, of natural gas to retail customers in 2022. In 2022, 99% of Entergy Louisianas operating revenue was derived from the electric utility business and only 1% from the natural gas distribution business. For Entergy New Orleans, 86% of operating revenue was derived from the electric utility business and 14% from the natural gas distribution business in 2022. Following is data concerning Entergy New Orleanss 2022 retail operating revenue sources: ##TABLE_START Customer Class % of Electric Operating Revenue % of Natural Gas Operating Revenue Residential 47 47 Commercial 36 26 Industrial 5 19 Governmental/Municipal 12 8 ##TABLE_ENDRetail Rate Regulation General (Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, Entergy Texas, System Energy) Each Utility operating company regularly participates in retail rate proceedings. The status of material retail rate proceedings is described in Note 2 to the financial statements. Certain aspects of the Utility operating companies retail rate mechanisms are discussed below. ##TABLE_START Rate base (in billions) Current authorized return on common equity Weighted average cost of capital (after-tax) Equity ratio Regulatory construct Entergy Arkansas $9.2 (a) 9.15% - 10.15% 5.25% 37.8% (b) - forward test year formula rate plan - riders: MISO, capacity, Grand Gulf, energy efficiency, fuel and purchased power Entergy Louisiana (electric) $14.4 (c) 9.0% - 10.0% 6.62% 49.41% - formula rate plan through 2022 test year - riders/specific recovery: MISO, capacity, transmission, fuel, distribution Entergy Louisiana (gas) $0.13 (d) 9.3% - 10.3% 6.76% 49.03% - gas rate stabilization plan - rider: gas infrastructure ##TABLE_ENDPart I Item 1 Entergy Corporation, Utility operating companies, and System Energy ##TABLE_START Entergy Mississippi $4.0 (e) 9.19% - 11.37% 6.71% 45.9% - formula rate plan with forward-looking features - riders: power management, Grand Gulf, fuel, MISO, unit power cost, storm damage, ad valorem tax adjustment, vegetation, grid modernization, restructuring credit Entergy New Orleans (electric) $1.2 (f) 8.85% - 9.85% 6.88% 51% - formula rate plan with forward-looking features - riders/specific recovery: fuel and purchased power, MISO, energy efficiency, environmental, capacity Entergy New Orleans (gas) $0.2 (f) 8.85% - 9.85% 6.88% 51% - formula rate plan with forward-looking features - rider: purchased gas Entergy Texas $2.4 (g) 9.65% 7.73% 50.90% - rate case - riders: fuel, capacity, cost recovery (distribution, transmission, and generation), rate case expenses, AMI surcharge, tax reform, among others System Energy $1.67 (h) 10.94% (i) 8.04 % 61% (i) - monthly cost of service ##TABLE_END(a) Based on 2023 test year. (b) Based on $1.9 billion in accumulated deferred income taxes at a 0% cost rate included in the weighted average cost of capital calculation. (c) Based on December 31, 2021 test year and includes approximately $800 million for the Lake Charles Power Station and excludes $250 million for the Washington Parish Energy Center included in the capacity rider, $400 million of transmission plant investment included in the transmission rider, and $200 million of distribution investment included in the distribution rider. (d) Based on September 30, 2021 test year. (e) Based on 2022 forward test year. (f) Based on December 31, 2021 test year and known and measurables through December 31, 2022. (g) Based on December 31, 2017 test year and excludes $1.7 billion in cost recovery riders. (h) Based on calculation as of December 31, 2022. (i) Effective July 2022, Entergy Mississippis bills from System Energy reflect an authorized return on equity of 9.65%, a capital structure not to exceed 52% equity, a rate base reduction for the advance collection of sale-leaseback rental costs, and the exclusion of certain long-term incentive plan performance unit costs from rates. See Note 2 to the financial statements for discussion of ongoing proceedings at the FERC challenging System Energys authorized return on common equity and capital structure. Entergy Arkansas Formula Rate Plan Between base rate cases, Entergy Arkansas is able to adjust base rates annually, subject to certain caps, through formula rate plans that utilize a forward test year. Entergy Arkansas is subject to a maximum rate change Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy of 4% of the filing year total retail revenue. In addition, Entergy Arkansas is subject to a true-up of projection to actuals netted with future projection. In response to Entergy Arkansass application for a general change in rates in 2015, the APSC approved the formula rate plan tariff proposed by Entergy Arkansas including its use of a projected year test period and an initial five-year term. The initial five-year term expired in 2021. As granted by Arkansas law, Entergy Arkansas obtained APSC approval of the extension of the formula rate plan tariff for an additional five-year term, through 2026. If Entergy Arkansass formula rate plan were terminated, Entergy Arkansas could file an application for a general change in rates that may include a request for continued regulation under a formula rate review mechanism. Fuel and Purchased Power Cost Recovery Entergy Arkansass rate schedules include an energy cost recovery rider to recover fuel and purchased power costs in monthly bills. The rider utilizes prior calendar year energy costs and projected energy sales for the twelve-month period commencing on April 1 of each year to develop an energy cost rate, which is redetermined annually and includes a true-up adjustment reflecting the over-recovery or under-recovery, including carrying charges, of the energy cost for the prior calendar year. The energy cost recovery rider tariff also allows an interim rate request depending upon the level of over- or under-recovery of fuel and purchased energy costs. In December 2007 the APSC issued an order stating that Entergy Arkansass energy cost recovery rider will remain in effect, and any future termination of the rider would be subject to eighteen months advance notice by the APSC, which would occur following notice and hearing. Production Cost Allocation Rider Entergy Arkansas has in place an APSC-approved production cost allocation rider for recovery from customers of the retail portion of the costs allocated to Entergy Arkansas as a result of System Agreement proceedings. Entergy Louisiana Formula Rate Plan Entergy Louisiana historically sets electric base rates annually through a formula rate plan using a historic test year. The form of the formula rate plan, on a combined basis, was approved in connection with the business combination of Entergy Louisiana and Entergy Gulf States Louisiana and largely followed the formula rate plans that were approved by the LPSC in connection with the full electric base rate cases filed by those companies in February 2013. The formula rate plan was most recently extended through the test year 2022; certain modifications were made in that extension, including a decrease to the allowed return on equity, narrowing of the earnings dead band around the mid-point allowed return on equity, elimination of sharing above and below the earnings dead band, and the addition of a distribution cost recovery mechanism. The formula rate plan continues to include exceptions from the rate cap and sharing requirements for certain large capital investment projects, including acquisition or construction of generating facilities and purchase power agreements approved by the LPSC, certain transmission investments, and most recently, certain distribution investments, among other items. In the event that the electric formula rate plan is not renewed or extended or otherwise replaced, Entergy Louisiana would revert to the more traditional rate case environment with a rate case filing occurring as soon as mid-2023. Fuel Recovery Entergy Louisianas rate schedules include a fuel adjustment clause designed to recover the cost of fuel and purchased power costs. The fuel adjustment clause contains a surcharge or credit for deferred fuel expense and related carrying charges arising from the monthly reconciliation of actual fuel costs incurred with fuel cost revenues billed to customers, including carrying charges. See Note 2 to the financial statements for a discussion of proceedings related to audits of Entergy Louisianas fuel adjustment clause filings. Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy To help stabilize electricity costs, Entergy Louisiana received approval from the LPSC to hedge its exposure to natural gas price volatility through the use of financial instruments. Entergy Louisiana historically hedged approximately one-third of the projected exposure to natural gas price changes for the gas used to serve its native electric load for all months of the year. The hedge quantity was reviewed on an annual basis. In January 2018, Entergy Louisiana filed an application with the LPSC to suspend these seasonal hedging programs and implement financial hedges with terms up to five years for a portion of its natural gas exposure, which was approved in November 2018. Entergy Louisianas gas rates include a purchased gas adjustment clause based on estimated gas costs for the billing month adjusted by a surcharge or credit that arises from an annual reconciliation of fuel costs incurred with fuel cost revenues billed to customers, including carrying charges. Retail Rates - Gas In accordance with the settlement of Entergy Gulf States Louisianas gas rate stabilization plan for the test year ended September 30, 2012, in August 2014, Entergy Gulf States Louisiana submitted for consideration a proposal for implementation of an infrastructure rider to recover expenditures associated with strategic plant investment and relocation projects mandated by local governments. After review by the LPSC staff and inclusion of certain customer safeguards required by the LPSC staff, in December 2014, Entergy Gulf States Louisiana and the LPSC staff submitted a joint settlement for implementation of an accelerated gas pipe replacement program providing for the replacement of approximately 100 miles of pipe over the next ten years, as well as relocation of certain existing pipe resulting from local government-related infrastructure projects, and for a rider to recover the investment associated with these projects. The rider allows for recovery of approximately $65 million over ten years. The rider recovery will be adjusted on a quarterly basis to include actual investment incurred for the prior quarter and is subject to the following conditions, among others: a ten-year term; application of any earnings in excess of the upper end of the earnings band as an offset to the revenue requirement of the infrastructure rider; adherence to a specified spending plan, within plus or minus 20% annually; annual filings comparing actual versus planned rider spending with actual spending and explanation of variances exceeding 10%; and an annual true-up. The joint settlement was approved by the LPSC in January 2015. Implementation of the infrastructure rider commenced with bills rendered on and after the first billing cycle of April 2015. In April 2022 Entergy Louisiana submitted for consideration a proposal to extend the infrastructure rider to address replacement of an additional 187 miles of pipe. In December 2022 Entergy Louisiana and the LPSC staff submitted an uncontested settlement that extends the rider for an additional ten years beginning after the end of the current term of the rider in 2025. The extension is subject to the same customer safeguards and conditions as the original term of the rider. The extension allows for recovery of approximately $95 million over ten years. In February 2023, the uncontested settlement was approved by the LPSC. Storm Cost Recovery See Note 2 to the financial statements for a discussion of Entergy Louisianas filings to recover storm-related costs. Other In March 2016 the LPSC opened two dockets to examine, on a generic basis, issues that it identified in connection with its review of Cleco Corporations acquisition by third party investors. The first docket is captioned In re: Investigation of double leveraging issues for all LPSC-jurisdictional utilities, and the second is captioned In re: Investigation of tax structure issues for all LPSC-jurisdictional utilities. In April 2016 the LPSC clarified that the concerns giving rise to the two dockets arose as a result of its review of the structure of the Cleco-Macquarie transaction and that the specific intent of the directives is to seek more information regarding intra-corporate debt financing of a utilitys capital structure as well as the use of investment tax credits to mitigate the tax Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy obligation at the parent level of a consolidated entity. No schedule has been set for either docket, and limited discovery has occurred. In December 2019 an LPSC commissioner issued an unopposed directive to staff to research customer-centered options for all customer classes, as well as other regulatory environments, and recommend a plan for how to ensure customers are the focus. There was no opposition to the directive from other commissioners but several remarked that the intent of the directive was not initiated to pursue retail open access. In furtherance of the directive, the LPSC issued a notice of the opening of a docket to conduct a rulemaking to research and evaluate customer-centered options for all electric customer classes as well as other regulatory environments in January 2020. To date, the LPSC staff has requested multiple rounds of comments from stakeholders and conducted one technical conference. Topics on which comments have been filed include full and limited retail access, demand response, sleeved power purchase agreements, and energy efficiency. Neither the LPSC or the LPSC staff have made recommendations or adopted any rules. Entergy Mississippi Formula Rate Plan Since the conclusion in 2015 of Entergy Mississippis most recent base rate case, Entergy

Mississippi has set electric base rates annually through a formula rate plan. Between base rate cases, Entergy Mississippi is able to adjust base rates annually, subject to certain caps, through formula rate plans that utilize forward-looking features. In addition, Entergy Mississippi is subject to an annual look-back evaluation. Entergy Mississippi is allowed a maximum rate increase of 4% of each test years retail revenue. Any increase above 4% requires a base rate case. If Entergy Mississippis formula rate plan were terminated without replacement, it would revert to the more traditional rate case environment or seek approval of a new formula rate plan. In August 2012 the MPSC opened inquiries to review whether the then current formulaic methodology used to calculate the return on common equity in both Entergy Mississippis formula rate plan and Mississippi Power Companys annual formula rate plan was still appropriate or could be improved to better serve the public interest. The intent of this inquiry and review was for informational purposes only; the evaluation of any recommendations for changes to the existing methodology would take place in a general rate case or in the existing formula rate plan proceeding. In March 2013 the Mississippi Public Utilities Staff filed its consultants report which noted the return on common equity estimation methods used by Entergy Mississippi and Mississippi Power Company are commonly used throughout the electric utility industry. The report suggested ways in which the methods used by Entergy Mississippi and Mississippi Power Company might be improved, but did not recommend specific changes in the return on common equity formulas or calculations at that time. In June 2014 the MPSC expanded the scope of the August 2012 inquiry to study the merits of adopting a uniform formula rate plan that could be applied, where possible in whole or in part, to both Entergy Mississippi and Mississippi Power Company in order to achieve greater consistency in the plans. The MPSC directed the Mississippi Public Utilities Staff to investigate and review Entergy Mississippis formula rate plan rider schedule and Mississippi Power Companys Performance Evaluation Plan by considering the merits and deficiencies and possibilities for improvement of each and then to propose a uniform formula rate plan that, where possible, could be applicable to both companies. No procedural schedule has been set. In October 2014 the Mississippi Public Utilities Staff conducted a public technical conference to discuss performance benchmarking and its potential application to the electric utilities formula rate plans. The docket remains open. In December 2019 the MPSC approved Entergy Mississippis proposed revisions to its formula rate plan to provide for a mechanism in the formula rate plan, the interim capacity rate adjustment mechanism, to recover the non-fuel related costs of additional owned capacity acquired by Entergy Mississippi as well as to allow similar cost recovery treatment for other capacity acquisitions that are approved by the MPSC. The MPSC must approve recovery through the interim capacity rate adjustment for each new resource. In addition, the MPSC approved revisions to the formula rate plan which allows Entergy Mississippi to begin billing rate adjustments effective April Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy 1 of the filing year on a temporary basis subject to refund or credit to customers, subject to final MPSC order. The MPSC also authorized Entergy Mississippi to remove vegetation management costs from the formula rate plan and recover these costs through the establishment of a vegetation management rider. Fuel Recovery Entergy Mississippis rate schedules include energy cost recovery riders to recover fuel and purchased power costs. The energy cost rate for each calendar year is redetermined annually and includes a true-up adjustment reflecting the over-recovery or under-recovery of the energy costs as of the 12-month period ended September 30. Entergy Mississippis fuel cost recoveries are subject to annual audits conducted pursuant to the authority of the MPSC. The energy cost recovery riders allow interim rate adjustments depending on the level of over- or under-recovery of fuel and purchased energy costs. To help stabilize electricity costs, Entergy Mississippi received approval from the MPSC to hedge its exposure to natural gas price volatility through the use of financial instruments. Entergy Mississippi hedges approximately one-third of the projected exposure to natural gas price changes for the gas used to serve its native electric load for all months of the year. The hedge quantity is reviewed on an annual basis. Storm Cost Recovery See Note 2 to the financial statements for a discussion of recovery of Entergy Mississippis storm-related costs. Entergy New Orleans Formula Rate Plan As part of its determination of rates in the base rate case filed by Entergy New Orleans in 2018, in November 2019, the City Council issued a resolution resolving the rate case, with rates to become effective retroactive to August 2019. The resolution allows Entergy New Orleans to implement a three-year formula rate plan, beginning with the 2019 test year as adjusted for forward-looking known and measurable changes, with the filing for the first test year to be made in 2020. As part of a settlement of Entergy New Orleans appeal of the Councils decision in its 2018 base rate case, Entergy New Orleans agreed to postpone the filing of its first test year formula rate plan to 2021 and, in return, to be provided an additional test year for the three-year cycle. Accordingly, Entergy New Orleans will submit its final formula rate plan filing of the three-year cycle in April 2023 unless the formula rate plan is extended or renewed. See Note 2 to the financial statements for further discussion. Fuel Recovery Entergy New Orleanss electric rate schedules include a fuel adjustment tariff designed to reflect no more than targeted fuel and purchased power costs, adjusted by a surcharge or credit for deferred fuel expense arising from the monthly reconciliation of actual fuel and purchased power costs incurred with fuel cost revenues billed to customers, including carrying charges. Entergy New Orleanss gas rate schedules include a purchased gas adjustment to reflect estimated gas costs for the billing month, adjusted by a surcharge or credit similar to that included in the electric fuel adjustment clause, including carrying charges. To help stabilize gas costs, Entergy New Orleans seeks approval annually from the City Council to continue implementation of its natural gas hedging program consistent with the City Councils stated policy objectives. The program uses financial instruments to hedge exposure to volatility in the wholesale price of natural gas purchased to Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy serve Entergy New Orleans gas customers. Entergy New Orleans hedges up to 25% of actual gas sales made during the winter months. Storm Cost Recovery See Note 2 to the financial statements for a discussion of Entergy New Orleanss filings to recover storm-related costs. Entergy Texas Base Rates The base rates of Entergy Texas are established largely in traditional base rate case proceedings. Between base rate proceedings, Entergy Texas has available rate riders to recover the revenue requirements associated with certain incremental costs. Entergy Texas is required to file full base rate case proceedings every four years and within eighteen months of utilizing its generation cost recovery rider for investments above $200 million. Fuel Recovery Entergy Texass rate schedules include a fixed fuel factor to recover fuel and purchased power costs, including interest, that are not included in base rates. Semi-annual revisions of the fixed fuel factor are made in March and September based on the market price of natural gas and changes in fuel mix. The amounts collected under Entergy Texass fixed fuel factor and any interim surcharge or refund are subject to fuel reconciliation proceedings before the PUCT every three years, at a minimum. In the course of this reconciliation, the PUCT determines whether eligible fuel and fuel-related expenses and revenues are necessary and reasonable and makes a prudence finding for each of the fuel-related contracts entered into during the reconciliation period. The PUCT fuel cost proceedings are discussed in Note 2 to the financial statements. At the PUCTs April 2013 open meeting, the PUCT Commissioners discussed their view that a purchased power capacity rider was good public policy. The PUCT issued an order in May 2013 adopting the rule allowing for a purchased power capacity rider, subject to an offsetting adjustment for load growth. The rule, as adopted, also includes a process for obtaining pre-approval by the PUCT of purchased power agreements. No Texas utility, including Entergy Texas, has exercised the option to recover capacity costs under the new rider mechanism, but Entergy Texas will continue to evaluate the benefits of utilizing the rider to recover future capacity costs. Other Cost Recovery As discussed above, Entergy Texas has available rate riders to recover the revenue requirements associated with certain incremental costs. These riders include a transmission cost recovery factor rider mechanism for the recovery of transmission-related capital investments, a distribution cost recovery factor rider mechanism for the recovery of distribution-related capital investment, and a generation cost recovery rider mechanism for the recovery of generation-related capital investments. In June 2009 a law was enacted in Texas containing provisions that allow Entergy Texas to take advantage of a cost recovery mechanism that permits annual filings for the recovery of reasonable and necessary expenditures for transmission infrastructure improvement and changes in wholesale transmission charges. This mechanism was previously available to other non-ERCOT Texas utility companies, but not to Entergy Texas. In September 2011 the PUCT adopted a proposed rule implementing a distribution cost recovery factor to recover capital and capital-related costs related to distribution infrastructure. The distribution cost recovery factor permits utilities once per year to implement an increase or decrease in rates above or below amounts reflected in base rates to reflect distribution-related depreciation expense, federal income tax and other taxes, and return on Part I Item 1 Entergy Corporation, Utility operating companies, and System

Energy investment. The distribution cost recovery factor rider may be changed a maximum of four times between base rate cases. In September 2019 the PUCT initiated a rulemaking to promulgate a generation cost recovery rider rule, implementing legislation passed in the 2019 Texas legislative session intended to allow electric utilities to recover generation investments between base rate proceedings. The PUCT approved the final rule in July 2020. Storm Cost Recovery See Note 2 to the financial statements for a discussion of Entergy Texass filings to recover storm-related costs. Electric Industry Restructuring In June 2009 a law was enacted in Texas that required Entergy Texas to cease all activities relating to Entergy Texass transition to competition. The law allows Entergy Texas to remain a part of the SERC Reliability Corporation (SERC) Region, although it does not prevent Entergy Texas from joining another power region. The law provides that proceedings to certify a power region that Entergy Texas belongs to as a qualified power region can be initiated by the PUCT, or on motion by another party, when the conditions supporting such a proceeding exist. Under the law, the PUCT may not approve a transition to competition plan for Entergy Texas until the expiration of four years from the PUCTs certification of a qualified power region for Entergy Texas. The law further amended already existing law that had required Entergy Texas to propose for PUCT approval a tariff to allow eligible customers the ability to contract for competitive generation. The amending language in the law provides, among other things, that: 1) the tariff shall not be implemented in a manner that harms the sustainability or competitiveness of manufacturers who choose not to participate in the tariff; 2) Entergy Texas shall purchase competitive generation service, selected by the customer, and provide the generation at retail to the customer; and 3) Entergy Texas shall provide and price transmission service and ancillary services under that tariff at a rate that is unbundled from its cost of service. The law directs that the PUCT may not issue an order on the tariff that is contrary to an applicable decision, rule, or policy statement of a federal regulatory agency having jurisdiction. The PUCT determined that unrecovered costs that may be recovered through the rider consist only of those costs necessary to implement and administer the competitive generation program and do not include lost revenues or embedded generation costs. The amount of customer load that may be included in the competitive generation service program is limited to 115 MW. System Energy Cost of Service The rates of System Energy are established by the FERC, and the costs allowed to be charged pursuant to these rates are, in turn, passed through to the participating Utility operating companies through the Unit Power Sales Agreement, which has monthly billings that reflect the current operating costs of, and investment in, Grand Gulf. Retail regulators and other parties may seek to initiate proceedings at FERC to investigate the prudence of costs included in the rates charged under the Unit Power Sales Agreement and examine, among other things, the reasonableness or prudence of the operation and maintenance practices, level of expenditures, allowed rates of return and rate base, and previously incurred capital expenditures. The Unit Power Sales Agreement is currently the subject of several litigation proceedings at the FERC, including a challenge with respect to System

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Energys uncertain tax positions, sale leaseback arrangement, authorized return on equity and capital structure, and a separate proceeding for a broader investigation of rates under the Unit Power Sales Agreement. In addition, certain of the Utility operating companies retail regulators have filed a complaint at FERC challenging the 2012 extended power uprate of Grand Gulf and the operation and management of the plant, particularly during the time period 2016 - 2020. Beginning in 2021, System Energy implemented billing protocols to provide retail regulators with Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy information regarding rates billed under the Unit Power Sales Agreement. Entergy cannot predict the outcome of any of these proceedings, and an adverse outcome in any of them could have a material adverse effect on Entergys or System Energys results of operations, financial condition, or liquidity. See Note 2 to the financial statements for further discussion of the proceedings. Franchises Entergy Arkansas holds exclusive franchises to provide electric service in approximately 308 incorporated cities and towns in Arkansas. These franchises generally are unlimited in duration and continue unless the municipalities purchase the utility property. In Arkansas, franchises are considered to be contracts and, therefore, are governed pursuant to the terms of the franchise agreement and applicable statutes. Entergy Louisiana holds non-exclusive franchises to provide electric service in approximately 175 incorporated municipalities and in the unincorporated areas of approximately 59 parishes of Louisiana. Entergy Louisiana holds non-exclusive franchises to provide natural gas service to customers in the City of Baton Rouge and in East Baton Rouge Parish. Municipal franchise agreement terms range from 25 to 60 years while parish franchise terms range from 25 to 99 years. Entergy Mississippi has received from the MPSC certificates of public convenience and necessity to provide electric service to areas within 45 counties, including a number of municipalities, in western Mississippi. Under Mississippi statutory law, such certificates are exclusive. Entergy Mississippi may continue to serve in such municipalities upon payment of a statutory franchise fee, regardless of whether an original municipal franchise is still in existence. Entergy New Orleans provides electric and gas service in the City of New Orleans pursuant to indeterminate permits set forth in city ordinances. These ordinances contain a continuing option for the City of New Orleans to purchase Entergy New Orleanss electric and gas utility properties. Entergy Texas holds a certificate of convenience and necessity from the PUCT to provide electric service to areas within approximately 27 counties in eastern Texas and holds non-exclusive franchises to provide electric service in approximately 70 incorporated municipalities. Entergy Texas typically obtains 25-year franchise agreements as existing agreements expire. Entergy Texass electric franchises expire over the period 2023-2058. The business of System Energy is limited to wholesale power sales. It has no distribution franchises. Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy Property and Other Generation Resources Owned Generating Stations The total capability of the generating stations owned and leased by the Utility operating companies and System Energy as of December 31, 2022 is indicated below: ##TABLE_START Owned and

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Leased Capability MW(a) Company Total CT / CCGT (b) Legacy Gas/Oil Nuclear Coal Hydro Solar Entergy Arkansas 5,276 1,567 522 1,822 1,192 73 100 Entergy Louisiana 10,829 5,595 2,766 2,129 339 Entergy Mississippi 2,857 1,738 707 310 102 Entergy New Orleans 663 636 27 Entergy Texas 3,190 980 1,960 250 System Energy 1,260 1,260 Total 24,075 10,516 5,955 5,211 2,091 73 229 ##TABLE_END(a) Owned and Leased Capability is the dependable load carrying capability as demonstrated under actual operating conditions based on the primary fuel (assuming no curtailments) that each station was designed to utilize. (b) Represents Simple Cycle Combustion Turbine units and Combined Cycle Gas Turbine units. Summer peak load for the Utility has averaged 21,602 MW over the previous decade. The Utility operating companies load and capacity projections are reviewed periodically to assess the need and timing for additional generating capacity and interconnections. These reviews consider existing and projected demand, the availability and price of power, the location of new load, the economy, Entergys clean energy and other public policy goals, environmental regulations, and the age and condition of Entergys existing infrastructure. The Utility operating companies long-term resource strategy (Portfolio Transformation Strategy) calls for the bulk of capacity needs to be met through long-term resources, whether owned or contracted. Over the past decade, the Portfolio Transformation Strategy has resulted in the addition of about 8,975 MW of new long-term resources and the deactivation of about 4,881 MW of legacy generation. As MISO market participants, the Utility operating companies also participate in MISOs Day Ahead and Real Time Energy and Ancillary Services markets to economically dispatch generation and purchase energy to serve customers reliably and at the lowest reasonable cost. Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy Other Generation Resources RFP Procurements The Utility operating companies from time to time issue requests for proposals (RFP) to procure supply-side resources from sources other than the spot market to meet the unique regional needs of the Utility operating companies. The RFPs issued by the Utility operating companies have sought resources needed to meet near-term MISO reliability requirements as well as long-term requirements through a broad range of wholesale power products, including long-term contractual products and asset acquisitions. The RFP process has resulted in selections or acquisitions, including, among other things: Entergy Louisianas construction of the 980 MW, combined-cycle, gas turbine J. Wayne Leonard Power Station (previously referred to as the St. Charles generating facility) at its existing Little Gypsy electric generating station. The facility began commercial operation in May 2019; Entergy Louisianas construction of the 994 MW, combined-cycle, gas turbine Lake Charles generating facility at its existing Nelson electric generating station site. The facility began commercial operation in March 2020; Entergy Texass construction of the 993 MW, combined-cycle, gas turbine Montgomery County Power Station at its existing Lewis Creek electric generating station. The facility began commercial operation in January 2021; Entergy New Orleanss construction of the 20 MW solar photovoltaic facility, New Orleans Solar Station, located at the NASA Michoud Facility. The facility began commercial operation in December 2020; In December 2020, Entergy Texas selected the self-build alternative, Orange County Advanced Power Station, out of the 2020 Entergy Texas combined-cycle, gas turbine RFP. Regulatory approval was received in November 2022 and construction has commenced. The facility is expected to be in service by mid-2026; In March 2019, Entergy Arkansas signed an agreement for the purchase of an approximately 100 MW to-be-constructed solar photovoltaic energy facility, Searcy Solar facility, sited on approximately 800 acres in White County near Searcy, Arkansas. Entergy Arkansas received regulatory approval from the APSC in April 2020, and closed on the acquisition, through use of a tax equity partnership, in December 2021. The Searcy Solar facility was placed in service in January 2022; In November 2018, Entergy Mississippi signed an agreement for the purchase of an approximately 100 MW to-be-constructed solar photovoltaic energy facility, Sunflower Solar facility, sited on approximately 1,000 acres in Sunflower County, Mississippi. Entergy Mississippi received regulatory approval from the MPSC in April 2020, and the Sunflower Solar facility began commercial operation in September 2022; In June 2020, Entergy Arkansas signed an agreement for the purchase of an approximately 100 MW to-be-constructed solar photovoltaic energy facility, Walnut Bend Solar facility, that will be sited on approximately 1,000 acres in Lee County, Arkansas. In July 2021 the APSC issued an order approving the acquisition of the Walnut Bend Solar facility. The counter-party notified Entergy Arkansas that it was terminating the project, though it was willing to consider an alternative for the site. Entergy Arkansas disputed the right of termination. Negotiations are ongoing, including with respect to cost and schedule and to updates arising as a result of the Inflation Reduction Act of 2022, and the updates would require additional APSC approval. At this time the project, if approved, is expected to achieve commercial operation in 2024; In September 2020, Entergy Arkansas signed an agreement for the purchase of an approximately 180 MW to-be-constructed solar photovoltaic energy facility, West Memphis Solar facility, that will be sited on approximately 1,500 acres in Crittenden County, Arkansas. In October 2021 the APSC issued an order approving the acquisition of the West Memphis Solar facility. The counter-party notified Entergy Arkansas that it was seeking changes to certain terms of the build-own-transfer agreement, including both cost and schedule. In January 2023, Entergy Arkansas made a supplemental filing with the APSC. Following APSC supplemental approval, full notice to proceed will be issued with closing expected to occur in 2024; Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy In November 2021, Entergy Louisiana signed an agreement for the purchase of an approximately 150 MW to-be-constructed solar photovoltaic energy facility, St. Jacques facility, that will be sited in St. James Parish near Vacherie, Louisiana. In September 2022 the LPSC voted to approve the order including the St. Jacques facility; however, project details could be adjusted pending a final St. James Parish ruling on land use permit requirements. Closing is expected to occur in 2025 dependent upon the final St. James Parish ruling; and In August 2022, Entergy Arkansas signed an agreement for the purchase of an approximately 250 MW to-be-constructed solar photovoltaic energy facility, Driver Solar facility, that will be sited near Osceola, Arkansas. Also in August 2022, Entergy Arkansas received necessary approvals for the Driver Solar facility, and Entergy Arkansas has issued the counter-party full notice to proceed to begin construction. The parties are evaluating the effects of certain matters related to the Inflation Reduction Act of 2022, including the viability of a tax equity partnership. Closing is expected to occur by the end of 2024. The RFP process has also resulted in the selection, or confirmation of the economic merits of, long-term purchased power agreements (PPAs), including, among others: River Bends 30% life-of-unit PPA between Entergy Louisiana and Entergy New Orleans for 100 MW related to Entergy Louisianas unregulated portion of the River Bend nuclear station, which portion was formerly owned by Cajun; Entergy Arkansass wholesale base load capacity life-of-unit PPAs executed in 2003 totaling approximately 220 MW between Entergy Arkansas and Entergy Louisiana (110 MW) and between Entergy Arkansas and Entergy New Orleans (110 MW) related to the sale of a portion of Entergy Arkansass coal and nuclear base load resources (which had not been included in Entergy Arkansass retail rates); In September 2012, Entergy Gulf States Louisiana executed a 20-year agreement for 28 MW, with the potential to purchase an additional 9 MW when available, from Rain CII Carbon LLCs petroleum coke calcining facility in Sulphur, Louisiana. The facility began commercial operation in May 2013. Entergy Louisiana, as successor in interest to Entergy Gulf States Louisiana, now holds the agreement with the facility; In March 2013, Entergy Gulf States Louisiana executed a 20-year agreement for 8.5 MW from Agrilectric Power Partners, LPs refurbished rice hull-fueled electric generation facility located in Lake Charles, Louisiana. Entergy Louisiana, as successor in interest to Entergy Gulf States Louisiana, now holds the agreement with Agrilectric; In September 2013, Entergy Louisiana executed a 10-year agreement with TX LFG Energy, LP, a wholly-owned subsidiary of Montauk Energy Holdings, LLC, to purchase approximately 3 MW from its landfill gas-fueled power generation facility located in Cleveland, Texas; Entergy Mississippis cost-based purchase, beginning in January 2013, of 90 MW from Entergy Arkansass share of Grand Gulf (only 60 MW of this PPA came through the RFP process). Cost recovery for the 90 MW was approved by the MPSC in January 2013; In April 2015, Entergy Arkansas and Stuttgart Solar, LLC executed a 20-year agreement for 81 MW from a solar photovoltaic electric generation facility located near Stuttgart, Arkansas. The APSC approved the project and deliveries pursuant to that agreement commenced in June 2018; In November 2016, Entergy Louisiana and LS Power executed a 10-year agreement for 485 MW from the Carville Energy Center located in St. Gabriel, Louisiana. In November 2019, LS Power sold and transferred the Carville Energy Center and facility to Argo Infrastructure Partners, which included the power purchase agreement; In November 2016, Entergy Louisiana and Occidental Chemical Corporation executed a 10-year agreement for 500 MW from the Taft Cogeneration facility located in Hahnville, Louisiana. The transaction received regulatory approval and began in June 2018; In June 2017, Entergy Arkansas and Chicot Solar, LLC executed a

20-year agreement for 100 MW from a to-be-constructed solar photovoltaic electric generating facility located in Chicot County, Arkansas. The transaction received regulatory approval and the PPA began in November 2020; Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy In February 2018, Entergy Louisiana and LA3 West Baton Rouge, LLC (Capital Region Solar project) executed a 20-year agreement for 50 MW from a to-be-constructed solar photovoltaic electric generating facility located in West Baton Rouge Parish, Louisiana. The transaction received regulatory approval in February 2019 and the PPA began in October 2020; In July 2018, Entergy New Orleans and St. James Solar, LLC executed a 20-year agreement for 20 MW from a to-be-constructed solar photovoltaic electric generating facility located in St. James Parish, Louisiana. The transaction received regulatory approval in July 2019 and is targeting commercial operation in the first half of 2023; In August 2018, Entergy Louisiana and South Alexander Development I, LLC executed a 5-year agreement for 5 MW from a solar photovoltaic electric generating facility located in Livingston Parish, Louisiana. The PPA began in December 2020 and received regulatory approval in January 2021; In February 2019, Entergy New Orleans and Iris Solar, LLC executed a 20-year agreement for 50 MW from a to-be-constructed solar photovoltaic electric generating facility located in Washington Parish, Louisiana. The transaction received regulatory approval in July 2019 and achieved commercial operation in November 2022; In August 2020, Entergy Texas and Umbriel Solar, LLC executed a 20-year agreement for 150 MW from a to-be-constructed solar photovoltaic electric generating facility located in Polk County, Texas. The PPA is expected to start when the facility reaches commercial operation in December 2023; In June 2021, Entergy Louisiana and Sunlight Road Solar, LLC executed a 20-year agreement for 50 MW from a to-be-constructed solar photovoltaic electric generating facility located in Washington Parish, Louisiana. In September 2022 the LPSC voted to approve the order including this project. The facility is expected to reach commercial operation in December 2024; In June 2021, Entergy Louisiana and Vacherie Solar Energy Center, LLC executed a 20-year PPA for 150 MW from a to-be-constructed solar photovoltaic electric generating facility located in St. James Parish, Louisiana. In September 2022 the LPSC voted to approve the order including this project; however, project details could be adjusted pending a final St. James Parish ruling on land use permit requirements. The facility is expected to reach commercial operation in 2025; In November 2021, Entergy Louisiana signed a PPA for approximately 125 MW from a to-be-constructed solar photovoltaic energy facility located in Allen, Louisiana. In September 2022 the LPSC voted to approve the order including this project. The facility is expected to reach commercial operation in February 2024; In December 2022, Entergy Mississippi signed a PPA for approximately 150 MW from a to-be-constructed solar photovoltaic energy facility located in Hinds County, Mississippi. Following execution of the agreement, Entergy Mississippi filed a petition with the MPSC requesting all necessary approvals. The facility is expected to reach commercial operation in June 2026; In October 2022, Entergy Mississippi signed a PPA for approximately 100 MW from a to-be-constructed solar photovoltaic energy facility located in Tallahatchie County, Mississippi. Following execution of the agreement, Entergy Mississippi filed a petition with the MPSC requesting all necessary approvals. The facility is expected to reach commercial operation as early as May 2026; In October 2022, Entergy Mississippi signed a PPA for approximately 170 MW from a to-be-constructed solar photovoltaic energy facility located in Washington County, Mississippi. Following execution of the agreement, Entergy Mississippi filed a petition with the MPSC requesting all necessary approvals. The facility is expected to reach commercial operation as early as May 2026; In October 2022, Entergy Arkansas signed a PPA for approximately 200 MW from a to-be-constructed solar photovoltaic energy facility located in St. Francis County, Arkansas. Following execution of the agreement, Entergy Arkansas filed a petition with the APSC requesting all necessary approvals. The facility is expected to reach commercial operation as early as May 2025; In October 2022, Entergy Arkansas signed a PPA for approximately 200 MW from a to-be-constructed solar photovoltaic energy facility located in Mississippi County, Arkansas. Following execution of the agreement, Entergy Arkansas filed a petition with the APSC requesting all necessary approvals. The facility is expected to reach commercial operation as early as May 2025; and Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy In January 2023, Entergy Texas signed a PPA for approximately 150 MW from a to-be-constructed solar photovoltaic energy facility located in Walker County, Texas. The facility is expected to reach commercial operation as early as June 2026. In March 2021, Entergy Services, on behalf of Entergy Louisiana, issued an RFP for solar photovoltaic resources. Entergy Louisiana selected a combination of PPA and build-own-transfer resources by March 2022, some of which have been executed and are noted above and the remainder are in progress working through definitive agreements. In July 2021, Entergy Services, on behalf of Entergy Texas, issued an RFP for solar generation resources. Entergy Texas selected a combination of PPA and build-own-transfer resources in March 2022. One PPA was executed in January 2023 as noted above, and definitive agreements for the remaining resources are in progress. In August 2021, Entergy Services, on behalf of Entergy Arkansas, issued an RFP for solar photovoltaic and wind resources. Entergy Arkansas selected a combination of PPA and build-own-transfer resources in February 2022, some of which have been executed and are noted above and the remainder are in progress working through definitive agreements. In January 2022, Entergy Services, on behalf of Entergy Mississippi, issued an RFP for solar photovoltaic and wind resources. The RFP is seeking up to 500 MW through a combination of build-own-transfer agreements, self-build alternatives, and power purchase agreements that can provide cost-effective energy supply, fuel diversity, and other benefits to Entergy Mississippi customers. In June 2022, Entergy Services, on behalf of Entergy Louisiana, issued an RFP for solar photovoltaic and wind resources. The RFP is seeking up to 1500 MW through a combination of build-own-transfer agreements, self-build alternatives, and power purchase agreements that can provide cost-effective energy supply, fuel diversity, and other benefits to Entergy Louisiana customers. In April 2022, Entergy Services, on behalf of Entergy Arkansas, issued an RFP for solar photovoltaic and wind resources. The RFP is seeking up to 1000 MW through a combination of build-own-transfer agreements, self-build alternatives, and power purchase agreements that can provide cost-effective energy supply, fuel diversity, and other benefits to Entergy Arkansas customers. In October 2022, Entergy Services, on behalf of Entergy Texas, issued an RFP for solar photovoltaic and wind resources. The RFP is seeking up to 2000 MW through a combination of build-own-transfer agreements, self-build alternatives, and power purchase agreements that can provide cost-effective energy supply, fuel diversity, and other benefits to Entergy Texas customers. In November 2022, Entergy Services, on behalf of Entergy Mississippi, issued an RFP for solar photovoltaic and wind resources. The RFP is seeking up to 500 MW through a combination of build-own-transfer agreements, self-build alternatives, and power purchase agreements that can provide cost-effective energy supply, fuel diversity, and other benefits to Entergy Mississippi customers. Other Procurements From Third Parties The Utility operating companies have also made resource acquisitions outside of the RFP process, including Entergy Arkansass (Power Block 2), Entergy Louisianas (Power Blocks 3 and 4), and Entergy New Orleanss (Power Block 1) March 2016 acquisitions of the 1,980 MW (summer rating), natural gas-fired, combined-cycle gas turbine Union Power Station power blocks, each rated at 495 MW (summer rating); and Entergy Mississippis October 2019 acquisition of the 810 MW, combined-cycle, natural gas-fired Choctaw Generating Station. The Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy Utility operating companies have also entered into various limited- and long-term contracts in recent years as a result of bilateral negotiations. The Washington Parish Energy Center is a 361 MW natural gas-fired peaking power plant approximately 60 miles north of New Orleans on a site Entergy Louisiana purchased from Calpine in 2019. In May 2018, Entergy Louisiana received LPSC approval of its certification application for this simple-cycle power plant to be developed pursuant to an agreement between Calpine and Entergy Louisiana. Calpine began construction on the plant in early 2019 and Entergy Louisiana purchased the plant upon completion in November 2020. The Hardin County Peaking Facility, an existing 147 MW simple-cycle gas-fired peaking power plant in Kountze, Texas, previously owned by East Texas Electric Cooperative, was acquired by Entergy Texas in June 2021. The facility has been in operation since January 2010. Power Through Programs In December 2020, Entergy Texas filed an application with the PUCT to amend its certificate of convenience and necessity to own and operate up to 75 MW of natural gas-fired distributed generation to be installed at commercial and industrial customer premises. Under this proposal, Entergy Texas would own and operate a fleet of generators ranging from 100 kW to 10 MW that would supply a portion of Entergy Texass long-term resource needs and enhance the resiliency of Entergy Texass electric grid. This fleet of generators would also be available to customers during outages to supply backup electric service as part of a program known as Power Through. In its

2021 session, the Texas legislature modified the Texas Utilities Code to exempt generators under 10 megawatts from the requirement to obtain a certificate of convenience and necessity. In addition, the PUCT announced an intent to conduct a broad rulemaking related to distributed generation and recommended that utilities with pending applications addressing distributed generation withdraw them. Accordingly, Entergy Texas withdrew its application for a certificate of convenience and necessity and associated tariff from the PUCT without prejudice to refiling. Entergy Texas continues to deploy certain customer-sited distributed generators under an existing PUCT-approved tariff. In August 2022, Entergy Texas filed an application for PUCT approval of voluntary Rate Schedule Utility Owned Distributed Generation (UODG) through which it would charge host customers for back-up service from customer-sited Power Through generators. Based on the exemption enacted by the Texas legislature in 2021, Entergy Texass application was not required to, and did not, seek an amendment to its certificate of convenience and necessity in order to continue deploying Power Through generators. In October 2022 two intervenors filed requests for a hearing on Entergy Texass application. In October 2022 the PUCT staff filed a request that the proceeding be referred to the State Office of Administrative Hearings. In January 2023 the PUCT announced an intent to develop certain broadly applicable reliability metrics against which to measure distributed generation resources and directed Entergy Texas to withdraw its application. However, the PUCT did allow Entergy Texas to continue its pilot program for Power Through generators. Entergy Texas has withdrawn its application and is considering next steps. In August 2021, Entergy Arkansas filed with the APSC an application for authority to deploy natural gas-fired distributed generation. The application was supported by a number of letters of interest from Entergy Arkansas customers. In December 2021 the APSC general staff requested briefing, which Entergy Arkansas opposed. In January 2022, Entergy Arkansas filed to support the establishment of a procedural schedule with a hearing in April 2022. Also in January 2022, the APSC granted the general staffs request for briefing but on an expedited schedule; briefing concluded in February 2022. Based on testimony filed to date the APSC general staff, Arkansas Electric Energy Consumers, Sierra Club, and Audubon oppose Entergy Arkansass proposed Power Through offering, which has been demonstrated to be in high demand by interested customers, some of which directly have filed public comments encouraging the APSC to approve the application. A paper hearing was held in August and September 2022 with Entergy Arkansas responding to several written commissioner questions. The parties are awaiting a decision from the APSC. Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy In July 2021, Entergy Louisiana filed with the LPSC an application for authority to deploy natural gas-fired distributed generation. The application was supported by a number of letters of interest from Entergy Louisiana customers. In October 2021, a procedural schedule was established with a hearing in April 2022. Staff and certain intervenors filed direct testimony in December 2021, and cross-answering testimony was filed in January 2022. Entergy Louisiana filed rebuttal testimony in February 2022.

The parties reached an uncontested settlement which, among other things, recommended approval of 120 MW of natural gas fired distributed generation and an additional 30 MW of solar and battery distributed generation, for a total distributed generation program of 150 MW. Pursuant to the terms of the settlement agreement, Entergy Louisiana may seek to expand the distributed generation program following the earlier of two years after issuance of an order approving the settlement or the installation of 60 MW of distributed generation pursuant to this program. The settlement was approved by the LPSC in November 2022. Interconnections The Utility operating companies generating units are interconnected to a transmission system operating at various voltages up to 500 kV. These generating units consist of steam-turbine generators fueled by natural gas and coal, combustion-turbine generators, and reciprocating internal combustion engine generators that are fueled by natural gas, generators powered by pressurized and boiling water nuclear reactors and inverter-based resources interconnecting both solar photovoltaic systems and energy storage devices that operate in the MISO wholesale electric market. Additionally, some of the Utility operating companies also offer customer services and products that include resources interconnected to both the distribution and transmission systems that also participate in the wholesale market. Entergys Utility operating companies are MISO market participants and the companies transmission systems are interconnected with those of many neighboring utilities. MISO is an essential link in the safe, cost-effective delivery of electric power across all or parts of 15 U.S. states and the Canadian province of Manitoba. In addition, the Utility operating companies are members of SERC Reliability Corporation (SERC), the Regional Entity with delegated authority from the North American Electric Reliability Corporation (NERC) for the purpose of proposing and enforcing Bulk Electric System reliability standards within 16 central and southeastern states. Gas Property As of December 31, 2022, Entergy New Orleans distributed and transported natural gas for distribution within New Orleans, Louisiana, through approximately 2,600 miles of gas pipeline. As of December 31, 2022, the gas properties of Entergy Louisiana, which are located in and around Baton Rouge, Louisiana, were not material to Entergy Louisianas financial position. Title The Utility operating companies generating stations are generally located on properties owned in fee simple. Most of the substations and transmission and distribution lines are constructed on private property or public rights-of-way pursuant to easements, servitudes, or appropriate franchises. Some substation properties are owned in fee simple. The Utility operating companies generally have the right of eminent domain, whereby they may perfect title to, or secure easements or servitudes on, private property for their utility operations. Substantially all of the physical properties and assets owned by Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, Entergy Texas, and System Energy are subject to the liens of mortgages securing bonds issued by those companies. The Lewis Creek generating station of Entergy Texas was acquired by merger with a subsidiary of Entergy Texas and is currently not subject to the lien of the Entergy Texas indenture. Part I Item 1 Entergy

Corporation, Utility operating companies, and System Energy Fuel Supply The average fuel cost per kWh for the Utility operating companies and System Energy for the years 2020-2022 were: ##TABLE_START Year Natural Gas Nuclear Coal Renewables (a) Purchased Power MISO Purchases (b) 2022 (Cents Per kWh) Entergy Arkansas 4.98 0.52 2.93 2.11 10.90 (2.65) Entergy Louisiana 5.50 0.57 2.84 10.70 6.95 6.45 Entergy Mississippi 4.38 2.85 0.04 6.53 6.68 Entergy New Orleans (c) 5.10 (5.16) 7.21 Entergy Texas 5.77 2.83 6.26 5.61 6.68 System Energy 0.65 Utility 5.27 0.57 2.89 7.00 6.54 5.95 2021 Entergy Arkansas 4.11 0.56 2.43 2.85 2.53 3.87 Entergy Louisiana 3.77 0.56 2.62 10.87 5.52 4.04 Entergy Mississippi 2.71 2.53 1.22 2.70 4.16 Entergy New Orleans (c) 3.47 (2.82) 4.50 Entergy Texas 4.65 2.60 3.97 4.53 4.10 System Energy 0.55 Utility 3.75 0.56 2.48 9.07 4.76 4.08 2020 Entergy Arkansas 1.78 0.62 2.35 2.28 7.39 0.63 Entergy Louisiana 1.98 0.58 3.27 9.99 3.48 2.65 Entergy Mississippi 1.73 2.52 0.25 3.23 2.26 Entergy New Orleans 1.56 0.02 2.99 Entergy Texas 2.23 3.17 3.61 3.29 2.71 System Energy 0.39 Utility 1.92 0.57 2.54 8.28 3.35 2.48 ##TABLE_END(a) Includes average fuel costs from both owned and purchased power resources. (b) Includes activity from financial transmission rights. See Note 15 to the financial statements for discussion of financial transmission rights. (c) Entergy New Orleanss renewables include liquidated damage payments of $2.9 million in 2022 and $1 million in 2021 due to the delay of in-service dates related to purchased power agreements. Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy Actual 2022 and projected 2023 sources of generation for the Utility operating companies and System Energy, including certain power purchases from affiliates under life of unit power purchase agreements, including the Unit Power Sales Agreement, are: ##TABLE_START 2022 CT / CCGT (b) Legacy Gas Nuclear Coal Renewables (c) Purchased Power (d) MISO Purchases (e) Entergy Arkansas 30 % 1 % 50 % 12 % 3 % % 4 % Entergy Louisiana 44 % 9 % 23 % 3 % 2 % 8 % 11 % Entergy Mississippi 59 % 6 % 18 % 7 % 1 % % 9 % Entergy New Orleans 54 % 1 % 35 % 1 % 1 % 1 % 7 % Entergy Texas 31 % 20 % 11 % 5 % % 9 % 24 % System Energy (a) % % 100 % % % % % Utility 42 % 8 % 27 % 5 % 2 % 5 % 11 % ##TABLE_END##TABLE_START 2023 CT / CCGT (b) Legacy Gas Nuclear Coal Renewables (c) Purchased Power (d) MISO Purchases (e) Entergy Arkansas 26 % % 58 % 13 % 3 % % % Entergy Louisiana 47 % 5 % 30 % 3 % 3 % 12 % % Entergy Mississippi 63 % % 26 % 10 % 1 % % % Entergy New Orleans 48 % 1 % 45 % 2 % 3 % 1 % % Entergy Texas 44 % 31 % 15 % 9 % % 1 % % System Energy (a) % % 100 % % % % % Utility 44 % 6 % 36 % 7 % 2 % 5 % % ##TABLE_END(a) Capacity and energy from System Energys interest in Grand Gulf is allocated as follows under the Unit Power Sales Agreement: Entergy Arkansas - 36%; Entergy Louisiana - 14%; Entergy Mississippi - 33%; and Entergy New Orleans - 17%. Pursuant to purchased power agreements, Entergy Arkansas is selling a portion of its owned capacity and energy from Grand Gulf to Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans. (b) Represents natural gas sourced for Simple Cycle Combustion Turbine units and Combined Cycle Gas Turbine units. (c) Includes generation from both owned and purchased power resources. (d) Excludes MISO purchases and renewables purchased through purchased power agreements. (e) In December 2013, Entergy integrated its transmission system into the MISO RTO. Entergy offers all of its generation into the MISO energy market on a day-ahead and real-time basis and bids for power in the MISO energy market to serve the demand of its customers, with MISO making dispatch decisions. The MISO purchases metric provided for 2022 is not projected for 2023. Some of the Utilitys gas-fired plants are also capable of using fuel oil, if necessary. Although based on current economics the Utility does not expect fuel oil use in 2023, it is possible that various operational events including weather or pipeline maintenance may require the use of fuel oil. Natural Gas The Utility operating companies have long-term firm and short-term interruptible gas contracts for both supply and transportation. Over 50% of the Utility operating companies power plants maintain some level of long-term firm transportation. Short-term contracts and spot-market purchases satisfy additional gas requirements. Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy Entergy Texas owns a gas storage facility and Entergy Louisiana has a firm storage service agreement that provide reliable and flexible natural gas service to certain generating stations. Many factors, including wellhead deliverability, storage, pipeline capacity, and demand requirements of end users, influence the availability and price of natural gas supplies for power plants. Demand is primarily tied to weather conditions as well as to the prices and availability of other energy sources. Pursuant to federal and state regulations, gas supplies to power plants may be interrupted during periods of shortage. To the extent natural gas supplies are disrupted or natural gas prices significantly increase, the Utility operating companies may in some instances use alternate fuels, such as oil when available, or rely to a larger extent on coal, nuclear generation, and purchased power. Coal Entergy Arkansas has committed to six two- to three-year contracts that will supply approximately 85% of the total coal supply needs in 2023. These contracts are staggered in term so that not all contracts have to be renewed the same year. If needed, additional Powder River Basin (PRB) coal will be purchased through contracts with a term of less than one year to provide the remaining supply needs. Based on the high cost of alternate sources, modes of transportation, and infrastructure improvements necessary for its delivery, no alternative coal consumption is expected at Entergy Arkansas during 2023. Coal will be transported to Arkansas via an existing Union Pacific transportation agreement that is expected to provide all of Entergy Arkansass rail transportation requirements for 2023. Entergy Louisiana has committed to four two- to three-year contracts that will supply approximately 90% of Nelson Unit 6 coal needs in 2023. If needed, additional PRB coal will be purchased through contracts with a term of less than one year to provide the remaining supply needs. For the same reasons as the Entergy Arkansas plants, no alternative coal consumption is expected at Nelson Unit 6 during 2023. Coal will be transported to Nelson via an existing transportation agreement that is expected to provide all of Entergy Louisianas rail transportation requirements for 2023. Coal transportation delivery rates to Entergy Arkansas- and Entergy Louisiana-operated coal-fired units became constrained and were unable to fully meet supply needs and obligations beginning in August 2021. Deliveries remained constrained through 2022 with modest improvement expected later in 2023. Both Entergy Arkansas and Entergy Louisiana control enough railcars to satisfy the rail transportation requirement. The operator of Big Cajun 2 - Unit 3, Louisiana Generating, LLC, has advised Entergy Louisiana and Entergy Texas that it has adequate rail car and barge capacity to meet the volumes of PRB coal requested for 2023, but is also currently experiencing delivery constraints. Entergy Louisianas and Entergy Texass coal nomination requests to Big Cajun 2 - Unit 3 are made on an annual basis. Nuclear Fuel The nuclear fuel cycle consists of the following: mining and milling of uranium ore to produce a concentrate; conversion of the concentrate to uranium hexafluoride gas; enrichment of the uranium hexafluoride gas; fabrication of nuclear fuel assemblies for use in fueling nuclear reactors; and disposal of spent fuel. The Registrant Subsidiaries that own nuclear plants, Entergy Arkansas, Entergy Louisiana, and System Energy, are responsible through a shared regulated uranium pool for contracts to acquire nuclear material to be used in fueling Entergys Utility nuclear units. These companies own the materials and services in this shared regulated Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy uranium pool on a pro rata fractional basis determined by the nuclear generation capability of each company. Any liabilities for obligations of the pooled contracts are on a several but not joint basis. The shared regulated uranium pool maintains inventories of nuclear materials during the various stages of processing. The Registrant Subsidiaries purchase enriched uranium hexafluoride for their nuclear plant reload requirements at the average inventory cost from the shared regulated uranium pool. Entergy Operations, Inc. contracts separately for the fabrication of nuclear fuel as agent on behalf of each of the Registrant Subsidiaries that owns a nuclear plant. All contracts for the disposal of spent nuclear fuel are between the DOE and the owner of a nuclear power plant. Based upon currently planned fuel cycles, the Utility nuclear units have a diversified portfolio of contracts and inventory that provides substantially adequate nuclear fuel materials and conversion and enrichment services at what Entergy believes are reasonably predictable or fixed prices through most of 2027. Entergys ability to purchase nuclear fuel at reasonably predictable prices, however, depends upon the performance reliability of uranium miners, including their ability to work through supply disruptions caused by global events, such as the COVID-19 pandemic, or national events, such as political disruption. There are a number of possible supply alternatives that may be accessed to mitigate any supplier performance failure, including potentially drawing upon Entergys inventory intended for later generation periods depending upon its risk management strategy at that time, although the pricing of any alternate uranium supply from the market will be dependent upon the market for uranium supply at that time. In addition, some nuclear fuel contracts are on a non-fixed price basis subject to prevailing prices at the time of delivery. The effects of market price changes may be reduced and deferred by risk management strategies, such as negotiation of floor and ceiling amounts for long-term contracts, buying for inventory or entering into forward physical contracts at fixed prices when Entergy believes it is appropriate and useful. Entergy buys uranium from a diversified mix of sellers located in a diversified mix of countries, and from time to time purchases from nearly all qualified reliable major market participants worldwide that sell into the U.S. Entergys ability to assure nuclear fuel supply also depends upon the performance reliability of conversion, enrichment, and fabrication services providers. There are fewer of these providers than for uranium. For conversion and enrichment services, like uranium, Entergy diversifies its supply by supplier and country and may take special measures as needed to ensure supply of enriched uranium for the reliable fabrication of nuclear fuel. For fabrication services, each plant is dependent upon the effective performance of the fabricator of that plants nuclear fuel, therefore, Entergy provides additional monitoring, inspection, and oversight for the fabrication process to assure reliability and quality. Entergy Arkansas, Entergy Louisiana, and System Energy each have made arrangements to lease nuclear fuel and related equipment and services. The lessors, which are consolidated in the financial statements of Entergy and the applicable Registrant Subsidiary, finance the acquisition and ownership of nuclear fuel through credit agreements and the issuance of notes. These credit facilities are subject to periodic renewal, and the notes are issued periodically, typically for terms between three and seven years. Natural Gas Purchased for Resale Entergy New Orleans has several suppliers of natural gas. Its system is interconnected with one interstate and three intrastate pipelines. Entergy New Orleans has a no-notice service gas purchase contract with Symmetry Energy Solutions which guarantees Entergy New Orleans gas delivery at specific delivery points and at any volume within the minimum and maximum set forth in the contract amounts. The Symmetry Energy Solutions gas supply is transported to Entergy New Orleans pursuant to a transportation service agreement with Gulf South Pipeline Co. This service is subject to FERC-approved rates. Entergy New Orleans also makes interruptible spot market purchases. Entergy Louisiana purchased natural gas for resale in 2022 under a firm contract from Sequent Energy Management L.P. The gas is delivered through a combination of intrastate and interstate pipelines. Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy As a result of the implementation of FERC-mandated interstate pipeline restructuring in 1993, curtailments of interstate gas supply could occur if Entergy Louisianas or Entergy New Orleanss suppliers failed to perform their obligations to deliver gas under their supply agreements. Gulf South Pipeline Co. could curtail transportation capacity only in the event of pipeline system constraints. Federal Regulation of the Utility State or local regulatory authorities, as described above, regulate the retail rates of the Utility operating companies. The FERC regulates wholesale sales of electricity rates and interstate transmission of electricity, including System Energys sales of capacity and energy from Grand Gulf to Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans pursuant to the Unit Power Sales Agreement. See Note 2 to the financial statements for further discussion of federal regulation proceedings. Transmission and MISO Markets In December 2013 the Utility operating companies integrated into the MISO RTO.

Although becoming a member of MISO did not affect the ownership by the Utility operating companies of their transmission facilities or the responsibility for maintaining those facilities, MISO maintains functional control over the combined transmission systems of its members and administers wholesale energy and ancillary services markets for market participants in the MISO region, including the Utility operating companies. MISO also exercises functional control of transmission planning and congestion management and provides schedules and pricing for the commitment and dispatch of generation that is offered into MISOs markets, as well as pricing for load that bids into the markets. The Utility operating companies sell capacity, energy, and ancillary services on a bilateral basis to certain wholesale customers and offer available electricity production of their generating facilities into the MISO day-ahead and real-time energy markets pursuant to the MISO tariff and market rules. Each Utility operating company has its own transmission pricing zone and a formula rate template (included as Attachment O to the MISO tariff) used to establish transmission rates within MISO. The terms and conditions of the MISO tariff, including provisions related to the design and implementation of wholesale markets and the allocation of transmission upgrade costs, are subject to regulation by the FERC. System Energy and Related Agreements System Energy recovers costs related to its interest in Grand Gulf through rates charged to Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans for capacity and energy under the Unit Power Sales Agreement (described below). In 1998 the FERC approved requests by Entergy Arkansas and Entergy Mississippi to accelerate a portion of their Grand Gulf purchased power obligations. Entergy Arkansass and Entergy Mississippis acceleration of Grand Gulf purchased power obligations ceased effective July 2001 and July 2003, respectively, as approved by the FERC. See Note 2 to the financial statements for discussion of proceedings at the FERC related to System Energy. Unit Power Sales Agreement The Unit Power Sales Agreement allocates capacity, energy, and the related costs from System Energys ownership and leasehold interests in Grand Gulf to Entergy Arkansas (36%), Entergy Louisiana (14%), Entergy Mississippi (33%), and Entergy New Orleans (17%). Each of these companies is obligated to make payments to System Energy for its entitlement of capacity and energy on a full cost-of-service basis regardless of the quantity of energy delivered. Payments under the Unit Power Sales Agreement are System Energys only source of operating revenue. The financial condition of System Energy depends upon the continued commercial operation of Grand Gulf and the receipt of such payments. Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans generally recover payments made under the Unit Power Sales Agreement through rates charged to their customers. Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy In the case of Entergy Arkansas and Entergy Louisiana, payments are also recovered through sales of electricity from their respective retained shares of Grand Gulf. Under a settlement agreement entered into with the APSC in 1985 and amended in 1988, Entergy Arkansas retains 22% of its 36% share of Grand Gulf-related costs and recovers the remaining 78% of its share in rates. In the event that Entergy Arkansas is not able to sell its retained share to third parties, it may sell such energy to its retail customers at a price equal to its avoided cost, which is currently less than Entergy Arkansass cost from its retained share. Entergy Arkansas has life-of-resources purchased power agreements with Entergy Louisiana and Entergy New Orleans that sell a portion of the output of Entergy Arkansass retained share of Grand Gulf to those companies, with the remainder of the retained share being sold to Entergy Mississippi through a separate life-of-resources purchased power agreement. In a series of LPSC orders, court decisions, and agreements from late 1985 to mid-1988, Entergy Louisiana was granted cost recovery with respect to costs associated with Entergy Louisianas share of capacity and energy from Grand Gulf, subject to certain terms and conditions. Entergy Louisiana retains and does not recover from retail ratepayers 18% of its 14% share of the costs of Grand Gulf capacity and energy and recovers the remaining 82% of its share in rates. Entergy Louisiana is allowed to recover through the fuel adjustment clause at 4.6 cents per kWh for the energy related to its retained portion of these costs. Alternatively, Entergy Louisiana may sell such energy to non-affiliated parties at prices above the fuel adjustment clause recovery amount, subject to the LPSCs approval. Entergy Arkansas also has a life-of-resources purchased power agreement with Entergy Mississippi to sell a portion of the output of Entergy Arkansass non-retained share of Grand Gulf. Entergy Mississippi was granted cost recovery for those purchases by the MPSC through its annual unit power cost rate mechanism. Availability Agreement The Availability Agreement among System Energy and Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans was entered into in 1974 in connection with the original financing by System Energy of Grand Gulf. The Availability Agreement provides that System Energy make available to Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans all capacity and energy available from System Energys share of Grand Gulf. Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans also agreed severally to pay System Energy monthly for the right to receive capacity and energy from Grand Gulf in amounts that (when added to any amounts received by System Energy under the Unit Power Sales Agreement) would at least equal System Energys total operating expenses for Grand Gulf (including depreciation at a specified rate and expenses incurred in a permanent shutdown of Grand Gulf) and interest charges. The allocation percentages under the Availability Agreement are fixed as follows: Entergy Arkansas - 17.1%; Entergy Louisiana - 26.9%; Entergy Mississippi - 31.3%; and Entergy New Orleans - 24.7%. The allocation percentages under the Availability Agreement would remain in effect and would govern payments made under such agreement in the event of a shortfall of operating expense funds available to System Energy from other sources, including payments under the Unit Power Sales Agreement. System Energy has assigned its rights to payments and advances from Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans under the Availability Agreement as security for all of its outstanding series of first mortgage bonds, as well as for its outstanding term loan and the pollution control revenue refunding bonds issued on its behalf. In these assignments, Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans further agreed that, in the event they were prohibited by governmental action from making payments under the Availability Agreement (for example, if the FERC reduced or disallowed such payments as constituting excessive rates), they would then make subordinated advances to System Energy in the same amounts and at the same times as the prohibited payments. System Energy would not be allowed to repay these subordinated advances so long as it remained in default under the related indebtedness or in other similar circumstances. Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy Each of the assignment agreements relating to the Availability Agreement provides that Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans will make payments directly to System Energy. However, if there is an event of default, those payments must be made directly to the holders of indebtedness that are the beneficiaries of such assignment agreements. The payments must be made pro rata according to the amount of the respective obligations secured. The obligations of Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans to make payments under the Availability Agreement are subject to the receipt and continued effectiveness of all necessary regulatory approvals. Sales of capacity and energy under the Availability Agreement would require that the Availability Agreement be submitted to the FERC for approval with respect to the terms of such sale. No such filing with the FERC has been made because sales of capacity and energy from Grand Gulf are being made pursuant to the Unit Power Sales Agreement. If, for any reason, sales of capacity and energy are made in the future pursuant to the Availability Agreement, the jurisdictional portions of the Availability Agreement would be submitted to the FERC for approval. Since commercial operation of Grand Gulf began, payments under the Unit Power Sales Agreement to System Energy have exceeded the amounts payable under the Availability Agreement and, therefore, no payments under the Availability Agreement have ever been required. If Entergy Arkansas or Entergy Mississippi fails to make its Unit Power Sales Agreement payments, and System Energy is unable to obtain funds from other sources, Entergy Louisiana and Entergy New Orleans could become subject to claims or demands by System Energy or certain of its creditors for payments or advances under the Availability Agreement (or the assignments thereof) equal to the difference between their required Unit Power Sales Agreement payments and their required Availability Agreement payments because their Availability Agreement obligations exceed their Unit Power Sales Agreement obligations. The Availability Agreement may be terminated, amended, or modified by mutual agreement of the parties thereto, without further consent of any assignees or other creditors. Service Companies Entergy Services, a limited liability company wholly-owned by Entergy Corporation, provides management, administrative, accounting, legal, engineering, and other services primarily to the Utility operating companies, but also provides services to Entergy Wholesale Commodities. Entergy

Operations is also wholly-owned by Entergy Corporation and provides nuclear management, operations and maintenance services under contract for ANO, River Bend, Waterford 3, and Grand Gulf, subject to the owner oversight of Entergy Arkansas, Entergy Louisiana, and System Energy, respectively. Entergy Services and Entergy Operations provide their services to the Utility operating companies and System Energy on an at cost basis, pursuant to cost allocation methodologies for these service agreements that were approved by the FERC. Jurisdictional Separation of Entergy Gulf States, Inc. into Entergy Gulf States Louisiana and Entergy Texas Effective December 31, 2007, Entergy Gulf States, Inc. completed a jurisdictional separation into two vertically integrated utility companies, one operating under the sole retail jurisdiction of the PUCT, Entergy Texas, and the other operating under the sole retail jurisdiction of the LPSC, Entergy Gulf States Louisiana. Entergy Texas owns all Entergy Gulf States, Inc. distribution and transmission assets located in Texas, the gas-fired generating plants located in Texas, undivided 42.5% ownership shares of Entergy Gulf States, Inc.s 70% ownership interest in Nelson Unit 6 and 42% ownership interest in Big Cajun 2, Unit 3, which are coal-fired generating plants located in Louisiana, and other assets and contract rights to the extent related to utility operations in Texas. Entergy Louisiana, as successor in interest to Entergy Gulf States Louisiana, owns all of the remaining assets that were owned by Entergy Gulf States, Inc. On a book value basis, approximately 58.1% of the Entergy Gulf States, Inc. assets were allocated to Entergy Gulf States Louisiana and approximately 41.9% were allocated to Entergy Texas. Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy Entergy Texas purchases from Entergy Louisiana pursuant to a life-of-unit purchased power agreement a 42.5% share of capacity and energy from the 70% of River Bend subject to retail regulation. Entergy Texas was allocated a share of River Bends nuclear and environmental liabilities that is identical to the share of the plants output purchased by Entergy Texas under the purchased power agreement. In connection with the termination of the System Agreement effective August 31, 2016, the purchased power agreements that were put in place for certain legacy units at the time of the jurisdictional separation were also terminated at that time. See Note 2 to the financial statements for additional discussion of the purchased power agreements. Entergy Louisiana and Entergy Gulf States Louisiana Business Combination On October 1, 2015, the businesses formerly conducted by Entergy Louisiana (Old Entergy Louisiana) and Entergy Gulf States Louisiana (Old Entergy Gulf States Louisiana) were combined into a single public utility. In order to effect the business combination, under the Texas Business Organizations Code (TXBOC), Old Entergy Louisiana allocated substantially all of its assets to a new subsidiary, Entergy Louisiana Power, LLC, a Texas limited liability company (New Entergy Louisiana), and New Entergy Louisiana assumed the liabilities of Old Entergy Louisiana, in a transaction regarded as a merger under the TXBOC. Under the TXBOC, Old Entergy Gulf States Louisiana allocated substantially all of its assets to a new subsidiary (New Entergy Gulf States Louisiana) and New Entergy Gulf States Louisiana assumed the liabilities of Old Entergy Gulf States

Louisiana, in a transaction regarded as a merger under the TXBOC. New Entergy Gulf States Louisiana then merged into New Entergy Louisiana with New Entergy Louisiana surviving the merger. Thereupon, Old Entergy Louisiana changed its name from Entergy Louisiana, LLC to EL Investment Company, LLC and New Entergy Louisiana changed its name from Entergy Louisiana Power, LLC to Entergy Louisiana, LLC (Entergy Louisiana). With the completion of the business combination, Entergy Louisiana holds substantially all of the assets, and has assumed the liabilities, of Old Entergy Louisiana and Old Entergy Gulf States Louisiana. Entergy New Orleans Internal Restructuring In November 2017, pursuant to the agreement in principle, Entergy New Orleans, Inc. undertook a multi-step restructuring, including the following: Entergy New Orleans, Inc. redeemed its outstanding preferred stock at a price of approximately $21 million, which included a call premium of approximately $819,000, plus any accumulated and unpaid dividends. Entergy New Orleans, Inc. converted from a Louisiana corporation to a Texas corporation. Under the Texas Business Organizations Code (TXBOC), Entergy New Orleans, Inc. allocated substantially all of its assets to a new subsidiary, Entergy New Orleans Power, LLC, a Texas limited liability company (Entergy New Orleans Power), and Entergy New Orleans Power assumed substantially all of the liabilities of Entergy New Orleans, Inc. in a transaction regarded as a merger under the TXBOC. Entergy New Orleans, Inc. remained in existence and held the membership interests in Entergy New Orleans Power. Entergy New Orleans, Inc. contributed the membership interests in Entergy New Orleans Power to an affiliate (Entergy Utility Holding Company, LLC, a Texas limited liability company and subsidiary of Entergy Corporation). As a result of the contribution, Entergy New Orleans Power is a wholly-owned subsidiary of Entergy Utility Holding Company, LLC. In December 2017, Entergy New Orleans, Inc. changed its name to Entergy Utility Group, Inc., and Entergy New Orleans Power then changed its name to Entergy New Orleans, LLC. Entergy New Orleans, LLC holds substantially all of the assets, and has assumed substantially all of the liabilities, of Entergy New Orleans, Inc. The restructuring was accounted for as a transaction between entities under common control. Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy Entergy Arkansas Internal Restructuring In November 2018, Entergy Arkansas undertook a multi-step restructuring, including the following: Entergy Arkansas, Inc. redeemed its outstanding preferred stock at the aggregate redemption price of approximately $32.7 million. Entergy Arkansas, Inc. converted from an Arkansas corporation to a Texas corporation. Under the Texas Business Organizations Code (TXBOC), Entergy Arkansas, Inc. allocated substantially all of its assets to a new subsidiary, Entergy Arkansas Power, LLC, a Texas limited liability company (Entergy Arkansas Power), and Entergy Arkansas Power assumed substantially all of the liabilities of Entergy Arkansas, Inc., in a transaction regarded as a merger under the TXBOC. Entergy Arkansas, Inc. remained in existence and held the membership interests in Entergy Arkansas Power. Entergy Arkansas, Inc. contributed the membership interests in Entergy Arkansas Power to an affiliate (Entergy Utility Holding Company, LLC, a Texas limited liability company and subsidiary of Entergy Corporation). As a result of the contribution, Entergy Arkansas Power is a wholly-owned subsidiary of Entergy Utility Holding Company, LLC. In December 2018, Entergy Arkansas, Inc. changed its name to Entergy Utility Property, Inc., and Entergy Arkansas Power then changed its name to Entergy Arkansas, LLC. Entergy Arkansas, LLC holds substantially all of the assets, and assumed substantially all of the liabilities, of Entergy Arkansas, Inc. The transaction was accounted for as a transaction between entities under common control. Entergy Mississippi Internal Restructuring In November 2018, Entergy Mississippi undertook a multi-step restructuring, including the following: Entergy Mississippi, Inc. redeemed its outstanding preferred stock, at the aggregate redemption price of approximately $21.2 million. Entergy Mississippi, Inc. converted from a Mississippi corporation to a Texas corporation. Under the Texas Business Organizations Code (TXBOC), Entergy Mississippi, Inc. allocated substantially all of its assets to a new subsidiary, Entergy Mississippi Power and Light, LLC, a Texas limited liability company (Entergy Mississippi Power and Light), and Entergy Mississippi Power and Light assumed substantially all of the liabilities of Entergy Mississippi, Inc., in a transaction regarded as a merger under the TXBOC. Entergy Mississippi, Inc. remained in existence and held the membership interests in Entergy Mississippi Power and Light. Entergy Mississippi, Inc. contributed the membership interests in Entergy Mississippi Power and Light to an affiliate (Entergy Utility Holding Company, LLC, a Texas limited liability company and subsidiary of Entergy Corporation). As a result of the contribution, Entergy Mississippi Power and Light is a wholly-owned subsidiary of Entergy Utility Holding Company, LLC. In December 2018, Entergy Mississippi, Inc. changed its name to Entergy Utility Enterprises, Inc., and Entergy Mississippi Power and Light then changed its name to Entergy Mississippi, LLC. Entergy Mississippi, LLC holds substantially all of the assets, and assumed substantially all of the liabilities, of Entergy Mississippi, Inc. The restructuring was accounted for as a transaction between entities under common control. Entergy Wholesale Commodities See Entergy Wholesale Commodities Exit from the Merchant Power Business in Entergy Corporation and Subsidiaries Managements Financial Discussion and Analysis for discussion of the shutdown and sale of each of the Entergy Wholesale Commodities nuclear power plants. With the sale of Palisades in June 2022, Entergy completed its multi-year strategy to exit the merchant power business. Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy Entergy Wholesale Commodities includes the ownership of interests in non-nuclear power plants that sell the electric power produced by those plants to wholesale customers. Entergy Wholesale Commodities also provides decommissioning-related services to nuclear power plants owned by non-affiliated entities in the United States. Property Entergy Wholesale Commodities includes ownership in the following non-nuclear power plants: ##TABLE_START Plant Location Ownership Net Owned Capacity (a) Type Independence Unit 2; 842 MW Newark, AR 14% 121 MW(b) Coal Nelson Unit 6; 550 MW Westlake, LA 11% 60 MW(b) Coal ##TABLE_END(a) Net Owned Capacity refers to the nameplate rating on the generating unit. (b) The owned MW capacity is the portion of the plant capacity owned by Entergy Wholesale Commodities. For a complete listing of Entergys jointly-owned generating stations, refer to Jointly-Owned Generating Stations in Note 1 to the financial statements. All of Entergy Wholesale Commodities owned generation falls under the authority of MISO. Entergy Wholesale Commodities customers for the sale of both energy and capacity from its owned generation and its contracted power purchases include retail power providers, utilities, electric power co-operatives, power trading organizations, and other power generation companies. The majority of Entergy Wholesale Commodities owned generation and contracted power purchases are sold under cost-based contract. Other Business Activities TLG Services, a subsidiary in the Entergy Wholesale Commodities segment, offers decommissioning, engineering, and related services to nuclear power plant owners. Regulation of Entergys Business Federal Power Act The Federal Power Act provides the FERC the authority to regulate: the transmission and wholesale sale of electric energy in interstate commerce; the reliability of the high voltage interstate transmission system through reliability standards; sale or acquisition of certain assets; securities issuances; the licensing of certain hydroelectric projects; certain other activities, including accounting policies and practices of electric and gas utilities; and changes in control of FERC jurisdictional entities or rate schedules. The Federal Power Act gives the FERC jurisdiction over the rates charged by System Energy for Grand Gulf capacity and energy provided to Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy New Orleans and over the rates charged by Entergy Arkansas and Entergy Louisiana to unaffiliated wholesale customers. The FERC also regulates wholesale power sales between the Utility operating companies. In addition, the FERC regulates the MISO RTO, an independent entity that maintains functional control over the combined transmission systems of its members and administers wholesale energy, capacity, and ancillary services markets for market participants in the MISO region, including the Utility operating companies. FERC regulation of the MISO RTO includes regulation of the design and implementation of the wholesale markets administered by the MISO RTO, as Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy well as the rates, terms, and conditions of open access transmission service over the member systems and the allocation of costs associated with transmission upgrades. Entergy Arkansas holds a FERC license that expires in 2053 for two hydroelectric projects totaling 65 MW of capacity. State Regulation Utility Entergy Arkansas is subject to regulation by the APSC as to the following: utility service; utility service areas; retail rates and charges, including depreciation rates; fuel cost recovery, including audits of the energy cost recovery rider; terms and conditions of service; service standards; the acquisition, sale, or lease of any public utility plant or property constituting an operating unit or system; certificates of convenience and necessity and certificates of environmental compatibility and public need, as applicable, for generating and transmission facilities; avoided cost payments to non-exempt Qualifying Facilities; net energy metering; integrated resource planning; utility mergers and acquisitions and other changes of control; and the issuance and sale of certain securities. Additionally, Entergy Arkansas serves a limited number of retail customers in Tennessee. Pursuant to legislation enacted in Tennessee, Entergy Arkansas is subject to complaints before the Tennessee Regulatory Authority only if it fails to treat its retail customers in Tennessee in the same manner as its retail customers in Arkansas. Additionally, Entergy Arkansas maintains limited facilities in Missouri but does not provide retail electric service to customers in Missouri. Although Entergy Arkansas obtained a certificate with respect to its Missouri facilities, Entergy Arkansas is not subject to retail ratemaking jurisdiction in Missouri. Entergy Louisianas electric and gas business is subject to regulation by the LPSC as to the following: utility service; retail rates and charges, including depreciation rates; fuel cost recovery, including audits of the fuel adjustment clause, environmental adjustment charge, and purchased gas adjustment charge; terms and conditions of service; service standards; certification of certain transmission projects; certification of capacity acquisitions, both for owned capacity and for purchase power contracts that exceed either 5 MW or one year in term; procurement process to acquire capacity over 50 MW; audits of the energy efficiency rider; avoided cost payment to non-exempt Qualifying Facilities; integrated resource planning; net energy metering; and utility mergers and acquisitions and other changes of control. Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy Entergy Mississippi is subject to regulation by the MPSC as to the following: utility service; utility service areas; retail rates and charges, including depreciation rates; fuel cost recovery, including audits of the energy cost recovery mechanism; terms and conditions of service; service standards; certification of generating facilities and certain transmission projects; avoided cost payments to non-exempt Qualifying Facilities; integrated resource planning; net energy metering; and utility mergers, acquisitions, and other changes of control. Entergy Mississippi is also subject to regulation by the APSC as to the certificate of environmental compatibility and public need for the Independence Station, which is located in Arkansas. Entergy New Orleans is subject to regulation by the City Council as to the following: utility service; retail rates and charges, including depreciation rates; fuel cost recovery, including audits of the fuel adjustment charge and purchased gas adjustment charge; terms and conditions of service; service standards; audit of the environmental adjustment charge; certification of the construction or extension of any new plant, equipment, property, or facility that comprises more than 2% of the utilitys rate base; integrated resource planning; net energy metering; avoided cost payments to non-exempt Qualifying Facilities; issuance and sale of certain securities; and utility mergers and acquisitions and other changes of control. To the extent authorized by governing legislation, Entergy Texas is subject to the original jurisdiction of the municipal authorities of a number of incorporated cities in Texas with appellate jurisdiction over such matters residing in the PUCT. Entergy Texas is also subject to regulation by the PUCT as to the following: retail rates and charges, including depreciation rates, and terms and conditions of service in unincorporated areas of its service territory, and in municipalities that have ceded jurisdiction to the PUCT; fuel recovery, including reconciliations (audits) of the fuel adjustment charges; service standards; certification of certain transmission and generation projects; utility service areas, including extensions into new areas; avoided cost payments to non-exempt Qualifying Facilities; net energy metering; and utility mergers, sales/acquisitions/leases of plants over $10 million, sales of greater than 50% voting stock of utilities, and transfers of controlling interest in or operation of utilities. Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy Regulation of the Nuclear Power Industry Atomic Energy Act of 1954 and Energy Reorganization Act of 1974 Under the Atomic Energy Act of 1954 and the Energy Reorganization Act of 1974, the operation of nuclear plants is heavily regulated by the NRC, which has broad power to impose licensing and safety-related requirements. The NRC has broad authority to impose civil penalties or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Entergy Arkansas, Entergy Louisiana, and System Energy, as owners of all or portions of ANO, River Bend and Waterford 3, and Grand Gulf, respectively, and Entergy Operations, as the licensee and operator of these units, are subject to the jurisdiction of the NRC. Nuclear Waste Policy Act of 1982 Spent Nuclear Fuel Under the Nuclear Waste Policy Act of 1982, the DOE is required, for a specified fee, to construct storage facilities for, and to dispose of, all spent nuclear fuel and other high-level radioactive waste generated by domestic nuclear power reactors. Entergys nuclear owner/licensee subsidiaries have been charged fees for the estimated future disposal costs of spent nuclear fuel in accordance with the Nuclear Waste Policy Act of 1982. The affected Entergy companies entered into contracts with the DOE, whereby the DOE is to furnish disposal services at a cost of one mill per net kWh generated and sold after April 7, 1983, plus a one-time fee for generation prior to that date. Entergy Arkansas is the only one of the Utility operating companies that generated electric power with nuclear fuel prior to that date and has a recorded liability as of December 31, 2022 of $195.0 million for the one-time fee. The fees payable to the DOE may be adjusted in the future to assure full recovery. Entergy considers all costs incurred for the disposal of spent nuclear fuel, except accrued interest, to be proper components of nuclear fuel expense. Provisions to recover such costs have been or will be made in applications to regulatory authorities for the Utility plants. Entergys total spent fuel fees to date, including the one-time fee liability of Entergy Arkansas, have surpassed $1.7 billion (exclusive of amounts relating to Entergy plants that were paid or are owed by prior owners of those plants). The permanent spent fuel repository in the U.S. has been legislated to be Yucca Mountain, Nevada. The DOE is required by law to proceed with the licensing (the DOE filed the license application in June 2008) and, after the license is granted by the NRC, proceed with the repository construction and commencement of receipt of spent fuel. Because the DOE has not begun accepting spent fuel, it is in non-compliance with the Nuclear Waste Policy Act of 1982 and has breached its spent fuel disposal contracts. The DOE continues to delay meeting its obligation. Specific steps were taken to discontinue the Yucca Mountain project, including a motion to the NRC to withdraw the license application with prejudice and the establishment of a commission to develop recommendations for alternative spent fuel storage solutions. In August 2013 the U.S. Court of Appeals for the D.C. Circuit ordered the NRC to continue with the Yucca Mountain license review, but only to the extent of funds previously appropriated by Congress for that purpose and not yet used. Although the NRC completed the safety evaluation report for the license review in 2015, the previously appropriated funds are not sufficient to complete the review, including required hearings. The government has taken no effective action to date related to the recommendations of the appointed spent fuel study commission. Accordingly, large uncertainty remains regarding the time frame under which the DOE will begin to accept spent fuel from Entergys facilities for storage or disposal. As a result, continuing future expenditures will be required to increase spent fuel storage capacity at Entergys nuclear sites. Following the defunding of the Yucca Mountain spent fuel repository program, the National Association of Regulatory Utility Commissioners and others sued the government seeking cessation of collection of the one mill per net kWh generated and sold after April 7, 1983 fee. In November 2013 the D.C. Circuit Court of Appeals ordered the DOE to submit a proposal to Congress to reset the fee to zero until the DOE complies with the Nuclear Waste Policy Act or Congress enacts an alternative waste disposal plan. In January 2014 the DOE submitted the Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy proposal to Congress under protest, and also filed a petition for rehearing with the D.C. Circuit. The petition for rehearing was denied. The zero spent fuel fee went into effect prospectively in May 2014. As a result of the DOEs failure to begin disposal of spent nuclear fuel in 1998 pursuant to the Nuclear Waste Policy Act of 1982 and the spent fuel disposal contracts, Entergys nuclear owner/licensee subsidiaries have incurred and will continue to incur damages. These subsidiaries have been, and continue to be, involved in litigation to recover the damages caused by the DOEs delay in performance. See Note 8 to the financial statements for discussion of final judgments recorded by Entergy in 2020, 2021, and 2022 related to Entergys nuclear owner licensee subsidiaries litigation with the DOE. Through 2022, Entergys subsidiaries have won and collected on judgments against the government totaling approximately $1 billion. Pending DOE acceptance and disposal of spent nuclear fuel, the owners of nuclear plants are providing their own spent fuel storage. Storage capability additions using dry casks began operations at ANO in 1996, at River Bend in 2005, at Grand Gulf in 2006, and at Waterford 3 in 2011. These facilities will be expanded as needed. Nuclear Plant Decommissioning Entergy Arkansas, Entergy Louisiana, and System Energy are entitled to recover from customers through electric rates the estimated decommissioning costs for ANO, Waterford 3, and Grand Gulf, respectively. In addition, Entergy Louisiana and Entergy Texas are entitled to recover from customers through electric rates the estimated decommissioning costs for the portion of River Bend subject to retail rate regulation. The collections are deposited in trust funds that can only be used in accordance with NRC and other applicable regulatory requirements. Entergy periodically reviews and updates the estimated decommissioning costs to reflect inflation and changes in regulatory requirements and technology, and then makes applications to the regulatory authorities to reflect, in rates, the changes in projected decommissioning costs. In December 2018 the APSC ordered collections in rates for decommissioning ANO 2 and found that ANO 1s decommissioning was adequately funded without additional collections. In November 2021, Entergy Arkansas filed a revised decommissioning cost recovery tariff for ANO indicating that both ANO 1 and 2 decommissioning trusts were adequately funded without further collections, and in December 2021 the APSC ordered zero collections for ANO 1 and 2 decommissioning. In November 2022, Entergy Arkansas filed a revised decommissioning cost recovery tariff for ANO indicating that ANO 1s decommissioning trust was adequately funded, but that ANO 2s fund had a projected shortage as a result of a decline in decommissioning trust fund investment values over the past year. The filing proposes a reinstatement of decommissioning cost recovery for ANO 2. Management cannot predict the outcome of this filing. In July 2010 the LPSC approved increased decommissioning collections for Waterford 3 and the Louisiana regulated share of River Bend to address previously identified funding shortfalls. This LPSC decision contemplated that the level of decommissioning collections could be revisited should the NRC grant license extensions for both Waterford 3 and River Bend. In July 2019, following the NRC approval of license extensions for Waterford 3 and River Bend, Entergy Louisiana made a filing with the LPSC seeking to adjust decommissioning and depreciation rates for those plants, including one proposed scenario that would adjust Louisiana-jurisdictional decommissioning collections to zero for both plants (including an offsetting increase in depreciation rates). Because of the ongoing public health emergency arising from the COVID-19 pandemic and accompanying economic uncertainty, Entergy Louisiana determined that the relief sought in the filing was no longer appropriate, and in November 2020, filed an unopposed motion to dismiss the proceeding. Following that filing, in a December 2020 order, the LPSC dismissed the proceeding without prejudice. In July 2021, Entergy Louisiana made a filing with the LPSC to adjust Waterford 3 and River Bend decommissioning collections based on the latest site-specific decommissioning cost estimates for those plants. The filing seeks to increase Waterford 3 decommissioning collections and decrease River Bend decommissioning collections. The procedural schedule in the case has been suspended pending settlement negotiations. Management cannot predict the outcome of this filing. Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy In December 2010 the PUCT approved increased decommissioning collections for the Texas share of River Bend to address previously identified funding shortfalls. In December 2018 the PUCT approved a settlement that eliminated River Bend decommissioning collections for the Texas jurisdictional share of the plant based on a determination by Entergy Texas that the existing decommissioning fund was adequate following license renewal. In July 2022, Entergy Texas filed a rate case that proposed continuation of the cessation of River Bend decommissioning collections. In December 2022, Entergy Texas filed on behalf of the parties a motion to abate the hearing on the merits to give parties additional time to finalize a settlement, which was approved by the presiding ALJ along with an order for the parties to file monthly settlement status reports. Management cannot predict the outcome of this filing. In December 2016 the NRC issued a 20-year operating license renewal for Grand Gulf. In a 2017 filing at the FERC, System Energy stated that with the renewed operating license, Grand Gulfs decommissioning trust was sufficiently funded, and proposed, among other things, to cease decommissioning collections for Grand Gulf effective October 1, 2017. The FERC accepted a settlement including the proposed decommissioning revenue requirement by letter order in August 2018. Entergy currently believes its decommissioning funding will be sufficient for its nuclear plants subject to retail rate regulation, although decommissioning cost inflation and trust fund performance will ultimately determine the adequacy of the funding amounts. Plant owners are required to provide the NRC with a biennial report (annually for units that have shut down or will shut down within five years), based on values as of December 31, addressing the owners ability to meet the NRC minimum funding levels. Depending on the value of the trust funds, plant owners may be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional contributions to the trusts, to ensure that the trusts are adequately funded and that NRC minimum funding requirements are met. In March 2021 filings with the NRC were made reporting on decommissioning funding for all of Entergys subsidiaries nuclear plants. Those reports showed that decommissioning funding for each of the nuclear plants met the NRCs financial assurance requirements. Additional information with respect to Entergys decommissioning costs and decommissioning trust funds is found in Note 9 and Note 16 to the financial statements. Price-Anderson Act The Price-Anderson Act requires that reactor licensees purchase and maintain the maximum amount of nuclear liability insurance available and participate in an industry assessment program called Secondary Financial Protection in order to protect the public in the event of a nuclear power plant accident. The costs of this insurance are borne by the nuclear power industry. Congress amended and renewed the Price-Anderson Act in 2005 for a term through 2025. The Price-Anderson Act limits the contingent liability for a single nuclear incident to a maximum assessment of approximately $137.6 million per reactor (with 96 nuclear industry reactors currently participating). In the case of a nuclear event in which Entergy Arkansas, Entergy Louisiana, or System Energy is liable, protection is afforded through a combination of private insurance and the Secondary Financial Protection program. In addition to this, insurance for property damage, costs of replacement power, and other risks relating to nuclear generating units is also purchased. The Price-Anderson Act and insurance applicable to the nuclear programs of Entergy are discussed in more detail in Note 8 to the financial statements. NRC Reactor Oversight Process The NRCs Reactor Oversight Process is a program to collect information about plant performance, assess the information for its safety significance, and provide for appropriate licensee and NRC response. The NRC evaluates plant performance by analyzing two distinct inputs: inspection findings resulting from the NRCs inspection program and performance indicators reported by the licensee. The evaluations result in the placement of Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy each plant in one of the NRCs Reactor Oversight Process Action Matrix columns: licensee response column, or Column 1, regulatory response column, or Column 2, degraded cornerstone column, or Column 3, and multiple/repetitive degraded cornerstone column, or Column 4, and unacceptable performance, or Column 5. Plants in Column 1 are subject to normal NRC inspection activities. Plants in Column 2, Column 3, or Column 4 are subject to progressively increasing levels of inspection by the NRC. Continued plant operation is not permitted for plants in Column 5. All of the nuclear generating plants owned and operated by Entergys Utility business are currently in Column 1, except Waterford 3, which is in Column 2. In September 2022 the NRC placed Waterford 3 in Column 2 based on an error associated with a radiation monitor calibration. Entergy corrected the issue with the radiation monitor in February 2022; however, Waterford 3 is expected to remain in Column 2 until third quarter 2023 based on a subsequent radiation monitor calibration issue. Environmental Regulation Entergys facilities and operations are subject to regulation by various governmental authorities having jurisdiction over air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters. Management believes that Entergys businesses are in substantial compliance with environmental regulations currently applicable to its facilities and operations, with reference to possible exceptions noted below. Because environmental regulations are subject to change, future compliance requirements and costs cannot be precisely estimated. Except to the extent discussed below, at this time compliance with federal, state, and local provisions regulating the discharge of materials into the environment, or otherwise protecting the environment, is incorporated into the routine cost structure of Entergys businesses and is not expected to have a material effect on their competitive position, results of operations, cash flows, or financial position. Clean Air Act and Subsequent Amendments The Clean Air Act and its amendments establish several programs that currently or in the future may affect Entergys fossil-fueled generation facilities and, to a lesser extent, certain operations at nuclear and other facilities. Individual states also operate similar independent state programs or delegated federal programs that may include requirements more stringent than federal regulatory requirements. These programs include: new source review and preconstruction permits for new sources of criteria air pollutants, greenhouse gases, and significant modifications to existing facilities; acid rain program for control of sulfur dioxide (SO_2) and nitrogen oxides (NO_x); nonattainment area programs for control of criteria air pollutants, which could include fee assessments for air pollutant emission sources under Section 185 of the Clean Air Act if attainment is not reached in a timely manner; hazardous air pollutant emissions reduction programs; Interstate Air Transport; operating permit programs and enforcement of these and other Clean Air Act programs; Regional Haze programs; and new and existing source standards for greenhouse gas and other air emissions. National Ambient Air Quality Standards The Clean Air Act requires the EPA to set

National Ambient Air Quality Standards (NAAQS) for ozone, carbon monoxide, lead, nitrogen dioxide, particulate matter, and sulfur dioxide, and requires periodic review of those standards. When an area fails to meet an ambient standard, it is considered to be in nonattainment and is classified as marginal, moderate, serious, or severe. When an area fails to meet the ambient air standard, the EPA requires state regulatory authorities to prepare state implementation plans meant to cause progress toward bringing the area into attainment with applicable standards. Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy Ozone Nonattainment Entergy Texas operates two fossil-fueled generating facilities (Lewis Creek and Montgomery County Power Station) in a geographic area that is not in attainment with the applicable NAAQS for ozone. The ozone nonattainment area that affects Entergy Texas is the Houston-Galveston-Brazoria area. Both Lewis Creek and the Montgomery County Power Station hold all necessary permits for operation and comply with applicable air quality program regulations. Measures enacted to return the area to ozone attainment could make these program regulations more stringent. Entergy will continue to work with state environmental agencies on appropriate methods for assessing attainment and nonattainment with the ozone NAAQS. Potential SO 2 Nonattainment The EPA issued a final rule in June 2010 adopting an SO 2 1-hour national ambient air quality standard of 75 parts per billion. In Entergys utility service territory, only St. Bernard Parish and Evangeline Parish in Louisiana are designated as nonattainment. In August 2017 the EPA issued a letter indicating that East Baton Rouge and St. Charles parishes would be designated by December 31, 2020, as monitors were installed to determine compliance. In March 2021 the EPA published a final rule designating East Baton Rouge, St. Charles, St. James, and West Baton Rouge parishes in Louisiana as attainment/unclassifiable, and, in Texas, Jefferson County as attainment/unclassifiable and Orange County as unclassifiable. No challenges to these final designations were filed within the 60 day deadline. Entergy continues to monitor this situation. Hazardous Air Pollutants The EPA released the final Mercury and Air Toxics Standard (MATS) rule in December 2011, which had a compliance date, with a widely granted one-year extension, of April 2016. The required controls have been installed and are operational at all affected Entergy units. In May 2020 the EPA finalized a rule that finds that it is not appropriate and necessary to regulate hazardous air pollutants from electric steam generating units under the provisions of section 112(n) of the Clean Air Act. This is a reversal of the EPAs previous finding requiring such regulation. The final appropriate and necessary finding does not revise the underlying MATS rule. Several lawsuits have been filed challenging the appropriate and necessary finding. In February 2021 the D.C. Circuit granted the EPAs motion to hold the litigation in abeyance pending the agencys review of the appropriate and necessary rule. In February 2022 the EPA issued a proposed rule revoking the 2020 rule and determining, again, that it is appropriate and necessary to regulate hazardous air pollutants. The EPA is seeking additional information, which it could use to further tighten the standard. Entergy will continue to monitor this situation. Cross-State Air Pollution In March 2005 the EPA finalized the

Clean Air Interstate Rule (CAIR), which was intended to reduce SO_2 and NO_x emissions from electric generation plants in order to improve air quality in twenty-nine eastern states. The rule required a combination of capital investment to install pollution control equipment and increased operating costs through the purchase of emission allowances. Entergy began implementation in 2007, including installation of controls at several facilities and the development of an emission allowance procurement strategy. Based on several court challenges, CAIR and its subsequent versions, now known as the Cross-State Air Pollution Rule (CSAPR), have been remanded to and modified by the EPA on multiple occasions. In April 2022 the EPA published a rule to address interstate transport for the 2015 ozone NAAQS which will increase the stringency of the CSAPR program in all four of the states where the Utility operating companies operate. If finalized as proposed, the rule will significantly reduce emission allowances and would likely require the installation of post-combustion nitrogen oxides (NO_x) emissions controls on any coal or large legacy gas units that will operate beyond 2026 and are not currently equipped with such controls. Fifteen Entergy-owned units, totaling approximately 9,370 MW of total unit capacity, are identified by the EPA for selective catalytic reduction retrofits. Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy Based on the EPA estimates, Entergys share of the capital costs would be approximately $1.6 billion if all the identified units were in fact retrofitted. Additionally, the EPA is proposing controls on certain non-electric generating NO_x sources. Since releasing the proposed rule, the price for Group 3 NO_x sources allowances has increased significantly, peaking at over $45,000 per allowance in late August 2022 before stabilizing in the range of $15,000 to $18,000 per allowance since September 2022. Comments on the proposed rule were due in June 2022. MISO, other impacted regional transmission organizations, and various state public service commissions all filed comments expressing reliability concerns if the rule is finalized as proposed. Entergy filed individual comments which assert, in addition to other issues, that the EPAs proposal represents over-control of the Entergy units in Arkansas and Mississippi; the EPA should consider an alternative approach or provide flexibility for units with a limited remaining useful life; the EPA should consult with regional transmission organizations to determine the reliability impacts of the proposed rule; and the EPA should consider and incorporate current economic trends, including inflation, into any benefit-costs analysis supporting the rule. Regional Haze In June 2005 the EPA issued its final Clean Air Visibility Rule (CAVR) regulations that potentially could result in a requirement to install SO_2 and NO_x pollution control technology as Best Available Retrofit Control Technology to continue operating certain of Entergys fossil generation units. The rule leaves certain CAVR determinations to the states. This rule establishes a series of 10-year planning periods, with states required to develop State Implementation Plans (SIPs) for each planning period, with each SIP including such air pollution control measures as may be necessary to achieve the ultimate goal of the CAVR by the year 2064. The various states are currently in the process of developing SIPs to implement the second planning period of the CAVR, which addresses the

2018-2028 planning period. In January and February 2018, Entergy Arkansas, Entergy Mississippi, Entergy Power, and other co-owners received 60-day notice of intent to sue letters from the Sierra Club and the National Parks Conservation Association concerning allegations of violations of new source review and permitting provisions of the Clean Air Act at the Independence and White Bluff coal-burning units, respectively. In November 2018, following extensive negotiations, Entergy Arkansas, Entergy Mississippi, and Entergy Power entered a proposed settlement resolving those claims and reducing the risk that Entergy Arkansas, as operator of Independence and White Bluff, might be compelled under the Clean Air Acts regional haze program to install costly emissions control technologies. Consistent with the terms of the settlement, Entergy Arkansas, along with co-owners, agreed to begin using only low-sulfur coal at Independence and White Bluff by mid-2021; agreed to cease using coal at White Bluff and Independence by the end of 2028 and 2030, respectively; agreed to cease operation of the remaining gas unit at Lake Catherine by the end of 2027; reserved the option to develop new generating sources at each plant site; and committed to installing or proposing to regulators at least 800 MWs of renewable generation by the end of 2027, with at least half installed or proposed by the end of 2022 (which includes two existing Entergy Arkansas projects) and with all qualifying co-owner projects counting toward satisfaction of the obligation. Under the settlement, the Sierra Club and the National Parks Conservation Association also waived certain potential existing claims under federal and state environmental law with respect to specified generating plants. The settlement, which formally resolves a complaint filed by the Sierra Club and the National Parks Conservation Association, was subject to approval by the U.S. District Court for the Eastern District of Arkansas. In November 2020 the court denied motions by the Arkansas Attorney General and the Arkansas Affordable Energy Coalition to intervene and to stay the proceedings. The proposed intervenors did not appeal the ruling. The District Court approved and entered the proposed settlement in March 2021. Entergy met the settlement deadline to use low-sulfur coal and is on target to meet the other requirements of the settlement. See Remaining Useful Lives Review in the State and Local Rate Regulation and Fuel-Cost Recovery section of Entergy Arkansas, LLC and Subsidiaries Managements Financial Discussion and Analysis for discussion of the APSCs proceeding related to Entergy Arkansass utility generation units. The second planning period (2018-2028) for the regional haze program requires states to examine sources for impacts on visibility and to prepare SIPs by July 31, 2021 to ensure reasonable progress is being made to attain Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy visibility improvements. Entergy received information collection requests from the Arkansas and Louisiana Departments of Environmental Quality requesting an evaluation of technical and economic feasibility of various NO x and SO 2 control technologies for Independence, Nelson 6, Nelson Industrial Steam Company (NISCO), and Ninemile. Responses to the information collection requests have been submitted to the respective state agencies. Louisiana has issued its draft SIP which, at this time, does not propose any additional air emissions controls for the affected Entergy units in Louisiana. Some public commenters, however, believe additional air controls are cost-effective. It is not yet clear how the Louisiana Department of Environmental Quality (LDEQ) will respond in its final SIP, and the agency, like many other state agencies, did not meet the July 31, 2021 deadline to submit a SIP to the EPA for review. Similar to the LDEQ, the Arkansas Department of Energy and Environment, Division of Environmental Quality (ADEQ) did not meet the July 31, 2021 SIP submission deadline, but subsequently submitted it to the EPA for review. The ADEQ reviewed Entergys Independence plant, but determined that additional air emission controls would not be cost-effective considering the facilitys commitment to cease coal-fired combustion by December 31, 2030. The Texas Commission on Environmental Quality has completed its second-planning period SIP and submitted it to the EPA for review. There were no Entergy sources selected for additional emission controls. The Mississippi Department of Environmental Quality continues to develop its SIP, but there are no Entergy sources that are expected to be impacted. In August 2022 the EPA issued findings of failure to submit regional haze SIPs to 15 states, including Louisiana and Mississippi. These findings were effective September 2022 and start the two-year period for the EPA to either approve a SIP submitted by the state or issue a final federal plan. Greenhouse Gas Emissions In July 2019 the EPA released the Affordable Clean Energy Rule (ACE), which applies only to existing coal-fired electric generating units. The ACE determines that heat rate improvements are the best system of emission reductions and lists six candidate technologies for consideration by states at each coal unit. The rule and associated rulemakings by the EPA replace the Obama administrations Clean Power Plan, which established national emissions performance rates for existing fossil-fuel fired steam electric generating units and combustion turbines. The ACE rule provides states discretion in determining how the best system for emission reductions applies to individual units, including through the consideration of technical feasibility and the remaining useful life of the facility. The ADEQ and the LDEQ have issued information collection requests to Entergy facilities to help the states collect the information needed to determine the best system of emission reductions for each facility. Entergy responded to the requests. In January 2021 the U.S. Court of Appeals for the D.C. Circuit vacated ACE. The court held that ACE relied on an incorrect interpretation of the Clean Air Act that the statute expressly forecloses emission reduction approaches, such as emissions trading and generating shifting, that cannot be applied at and to the individual source. The court remanded ACE to the EPA for further consideration and also vacated the repeal of the Clean Power Plan. In March 2021 the D.C. Circuit issued a partial mandate vacating the ACE rule, but withheld the mandate vacating the repeal of the Clean Power Plan pending the EPAs new rulemaking to regulate greenhouse gas emissions. Thus, there currently is no regulation in place with respect to greenhouse gas emissions from existing electric generating units and states are not expected to take further action to develop and submit plans at this time. In October 2021 the United States Supreme Court agreed to hear a challenge to the already vacated ACE rule. In

June 2022 the United States Supreme Court held that the EPA could not use generation shifting as the best system of emission reduction under Section 111(d) of the Clean Air Act. The EPA does still have the authority to regulate greenhouse gas emissions, but those emissions reductions must be technology based. The EPA has announced its intent to propose a rule for existing power plants pursuant to the Clean Air Act by March 2023. The ultimate impact of the United States Supreme Court's decision cannot be determined at this time. Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy In April 2021, President Biden announced a target for the United States in connection with the United Nations Paris Agreement on climate change. The target consists of a 50-52 percent reduction in economy-wide net greenhouse gas emissions from 2005 levels by 2030. President Biden has also stated that a goal of his administration is for the electric power industry to decarbonize fully by 2035. The details surrounding implementation of these targets are not finalized, and the impacts to Entergy of any potential related legislation cannot be predicted. Entergy continues to support national legislation that would most efficiently reduce economy-wide greenhouse gas emissions and increase planning certainty for electric utilities. By virtue of its proportionally large investment in low-emitting generation technologies, Entergy has a low overall carbon dioxide emission intensity, or rate of carbon dioxide emitted per megawatt-hour of electricity generated. In anticipation of the imposition of carbon dioxide emission limits on the electric industry, Entergy initiated actions designed to reduce its exposure to potential new governmental requirements related to carbon dioxide emissions. These voluntary actions included a formal program to stabilize owned power plant carbon dioxide emissions at 2000 levels through 2005, and Entergy succeeded in reducing emissions below 2000 levels. In 2006, Entergy started including emissions from controllable power purchases in addition to its ownership share of generation and established a second formal voluntary program to stabilize power plant carbon dioxide emissions and emissions from controllable power purchases, cumulatively over the period, at 20% below 2000 levels through 2010. In 2011, Entergy extended this commitment through 2020, which it ultimately outperformed by approximately 8% both cumulatively and on an annual basis. In 2019, in connection with a climate scenario analysis following the recommendations of the Task Force on Climate-related Financial Disclosures describing climate-related governance, strategy, risk management, and metrics and targets, Entergy announced a 2030 carbon dioxide emission rate goal focused on a 50% reduction from Entergys base year - 2000. Entergy now anticipates achieving this reduction several years early. In September 2020, Entergy announced a commitment to achieve net-zero greenhouse gas emissions by 2050 inclusive of all businesses, all applicable gases, and all emission scopes. In 2022, Entergy enhanced its commitment to include an interim goal of 50% carbon-free energy generating capacity by 2030 and expanded its interim emission rate goal to include all purchased power. See Risk Factors in Part I Item 1A for discussion of the risks associated with achieving these climate goals. Entergys comprehensive, third-party verified greenhouse gas inventory and progress against its voluntary goals are published on its website. Entergy participates in the M.J. Bradley Associates Annual Benchmarking Air Emissions Report, an annual analysis of the 100 largest U.S. electric power producers. The report is available on the M.J. Bradley website. Entergy participates annually in the Dow Jones Sustainability Index and in 2022 was listed on the North American Index. Entergy has been listed on the World or North American Index, or both, for 21 consecutive years. Entergy also participated in the 2022 CDP Climate Change and CDP Water Security evaluations, receiving a B for both responses. Potential Legislative, Regulatory, and Judicial Developments In addition to the specific instances described above, there are a number of legislative and regulatory initiatives that are under consideration at the federal, state, and local level. Because of the nature of Entergys business, the imposition of any of these initiatives could affect Entergys operations. Entergy continues to monitor these initiatives and activities in order to analyze their potential operational and cost implications. These initiatives include: reconsideration and revision of ambient air quality standards downward which could lead to additional areas of nonattainment; designation by the EPA and state environmental agencies of areas that are not in attainment with national ambient air quality standards; introduction of bills in Congress and development of regulations by the EPA proposing further limits on SO_2, mercury, carbon dioxide, and other air emissions. New legislation or regulations applicable to Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy stationary sources could take the form of market-based cap-and-trade programs, direct requirements for the installation of air emission controls onto air emission sources, or other or combined regulatory programs; efforts in Congress or at the EPA to establish a federal carbon dioxide emission tax, control structure, or unit performance standards; revisions to the estimates of the Social Cost of Carbon and its use for regulatory impact analysis of federal laws and regulations; implementation of the regional cap and trade programs to limit carbon dioxide and other greenhouse gases; efforts on the local, state, and federal level to codify renewable portfolio standards, clean energy standards, or a similar mechanism requiring utilities to produce or purchase a certain percentage of their power from defined renewable energy sources or energy sources with lower emissions; efforts to develop more stringent state water quality standards, effluent limitations for Entergys industry sector, stormwater runoff control regulations, and cooling water intake structure requirements; efforts to restrict the previously-approved continued use of oil-filled equipment containing certain levels of polychlorinated biphenyls (PCBs); efforts by certain external groups to encourage reporting and disclosure of environmental, social, and governance risk; the listing of additional species as threatened or endangered, the protection of critical habitat for these species, and developments in the legal protection of eagles and migratory birds; the regulation of the management, disposal, and beneficial reuse of coal combustion residuals; and the regulation of the management and disposal and recycling of equipment associated with renewable and clean energy sources such as used solar panels, wind turbine blades, hydrogen usage, or battery storage. Clean Water Act The 1972 amendments to the Federal Water Pollution Control

Act (known as the Clean Water Act) provide the statutory basis for the National Pollutant Discharge Elimination System permit program, section 402, and the basic structure for regulating the discharge of pollutants from point sources to waters of the United States. The Clean Water Act requires virtually all discharges of pollutants to waters of the United States to be permitted. Section 316(b) of the Clean Water Act regulates cooling water intake structures, section 401 of the Clean Water Act requires a water quality certification from the state in support of certain federal actions and approvals, and section 404 regulates the dredge and fill of waters of the United States, including jurisdictional wetlands. Federal Jurisdiction of Waters of the United States In June 2020 the EPAs revised definition of waters of the United States in the Navigable Waters Protection Rule (NWPR) became effective, narrowing the scope of Clean Water Act jurisdiction, as compared to a 2015 definition which had been stayed by several federal courts. In August 2021 a federal district court vacated and remanded the NWPR for further consideration. The EPA and the U.S. Army Corps of Engineers (Corps) subsequently issued a statement that the agencies would revert to pre-2015 regulations pending a new rulemaking. In December 2022 the EPA and the Corps released a final definition of waters of the United States that replaces the NWPR with a definition that is consistent with the pre-2015 regulatory regime as interpreted by several United States Supreme Court decisions. Most notably, the exclusion for waste treatment systems is retained. Comprehensive Environmental Response, Compensation, and Liability Act of 1980 The Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended (CERCLA), authorizes the EPA to mandate clean-up by, or to collect reimbursement of clean-up costs from, owners or operators of sites at which hazardous substances may be or have been released. Certain private parties also may use CERCLA to recover response costs. Parties that transported hazardous substances to these sites or arranged for the disposal of the substances are also deemed liable by CERCLA. CERCLA has been interpreted to impose strict, joint, and several liability on responsible parties. Many states have adopted programs similar to CERCLA. Entergy subsidiaries in the Utility and Entergy Wholesale Commodities businesses have sent waste materials to various Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy disposal sites over the years, and releases have occurred at Entergy facilities including nuclear facilities that have been or will be sold to decommissioning companies. In addition, environmental laws now regulate certain of Entergys operating procedures and maintenance practices that historically were not subject to regulation. Some disposal sites used by Entergy subsidiaries have been the subject of governmental action under CERCLA or similar state programs, resulting in site clean-up activities. Entergy subsidiaries have participated to various degrees in accordance with their respective potential liabilities in such site clean-ups and have developed experience with clean-up costs. The affected Entergy subsidiaries have established provisions for the liabilities for such environmental clean-up and restoration activities. Details of potentially material CERCLA and similar state program liabilities are discussed in the Other Environmental Matters section below. Coal Combustion

Residuals In June 2010 the EPA issued a proposed rule on coal combustion residuals (CCRs) that contained two primary regulatory options: (1) regulating CCRs destined for disposal in landfills or received (including stored) in surface impoundments as so-called special wastes under the hazardous waste program of Resource Conservation and Recovery Act (RCRA) Subtitle C; or (2) regulating CCRs destined for disposal in landfills or surface impoundments as non-hazardous wastes under Subtitle D of RCRA. Under both options, CCRs that are beneficially reused in certain processes would remain excluded from hazardous waste regulation. In April 2015 the EPA published the final CCR rule with the material being regulated under the second scenario presented above - as non-hazardous wastes regulated under RCRA Subtitle D. The final regulations create new compliance requirements including modified storage, new notification and reporting practices, product disposal considerations, and CCR unit closure criteria. Entergy believes that on-site disposal options will be available at its facilities, to the extent needed for CCR that cannot be transferred for beneficial reuse. As of December 31, 2022, Entergy has recorded asset retirement obligations related to CCR management of $27 million. Pursuant to the EPA Rule, Entergy operates groundwater monitoring systems surrounding its coal combustion residual landfills located at White Bluff, Independence, and Nelson. Monitoring to date has detected concentrations of certain listed constituents in the area, but has not indicated that these constituents originated at the active landfill cells. Reporting has occurred as required, and detection monitoring will continue as the rule requires. In late-2017, Entergy determined that certain in-ground wastewater treatment system recycle ponds at its White Bluff and Independence facilities require management under the new EPA regulations. Consequently, in order to move away from using the recycle ponds, White Bluff and Independence each have installed a new permanent bottom ash handling system that does not fall under the CCR rule. As of November 2020, both sites are operating the new system and no longer are sending waste to the recycle ponds. Each site has commenced closure of its two recycle ponds (four ponds total), prior to the April 11, 2021 deadline under the finalized CCR rule for unlined recycle ponds. Any potential requirements for corrective action or operational changes under the new CCR rule continue to be assessed. Notably, ongoing litigation has resulted in the EPAs continuing review of the rule. Consequently, the nature and cost of additional corrective action requirements may depend, in part, on the outcome of the EPAs review. Other Environmental Matters Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, and Entergy Texas The EPA notified Entergy that the EPA believes Entergy is a PRP concerning PCB contamination at the F.J. Doyle Salvage facility in Leonard, Texas. The facility operated as a scrap salvage business during the 1970s to the 1990s. In May 2018 the EPA investigated the site surface and sub-surface soils and, in November 2018 the EPA conducted a removal action, including disposal of PCB contaminated soils. Entergy responded to the EPAs information requests in May and July 2019. In November 2020 the EPA sent Entergy and other PRPs a demand letter seeking reimbursement for response costs totaling $4 million expended at the site. Liability and

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PRP Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy allocation of response costs are yet to be determined. In December 2020, Entergy responded to the demand letter, without admitting liability or waiving any rights, indicating that it would engage in good faith negotiations with the EPA with respect to the demand. An initial meeting between the EPA and the PRPs took place in June 2021. Negotiations between the PRPs and the EPA are ongoing. Litigation Entergy uses legal and appropriate means to contest litigation threatened or filed against it, but certain states in which Entergy operates have proven to be unusually litigious environments. Judges and juries in Louisiana, Mississippi, and Texas have demonstrated a willingness to grant large verdicts, including punitive damages, to plaintiffs in personal injury, property damage, and business tort cases. The litigation environment in these states poses a significant business risk to Entergy. Asbestos Litigation (Entergy Arkansas, Entergy Louisiana, Entergy New Orleans, and Entergy Texas) See Note 8 to the financial statements for a discussion of this litigation. Employment and Labor-related Proceedings (Entergy Corporation, Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, Entergy Texas, and System Energy) See Note 8 to the financial statements for a discussion of these proceedings. Human Capital Employees Employees are an integral part of Entergys commitment to serving customers. As of December 31, 2022, Entergy subsidiaries employed 11,707 people. ##TABLE_START Utility: Entergy Arkansas 1,227 Entergy Louisiana 1,597 Entergy Mississippi 716 Entergy New Orleans 296 Entergy Texas 648 System Energy Entergy Operations 3,317 Entergy Services 3,870 Entergy Nuclear Operations 13 Other subsidiaries 23 Total Entergy 11,707 ##TABLE_ENDApproximately 3,084 employees are represented by the International Brotherhood of Electrical Workers, the United Government Security Officers of America, and the International Union, Security, Police, and Fire Professionals of America. Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy Below is the breakdown of Entergys employees by gender and race/ethnicity: ##TABLE_START Gender (%) 2022 2021 Female 22.2 21.4 Male 77.8 78.6 ##TABLE_END##TABLE_START Race/Ethnicity (%) 2022 2021 White 74.8 76.4 Black/African American 17.3 16.4 Hispanic/Latino 3.0 2.7 Asian 2.3 2.0 Other 2.6 2.5 ##TABLE_ENDEntergys Approach to Human Resources Entergys people and culture enable its success; that is why acquiring, retaining, and developing talent are important components of Entergys human resources strategy. Entergy focuses on an approach that includes, among other things, governance and oversight; safety; organizational health, including diversity, inclusion, and belonging; and talent management. Governance and Oversight Ensuring that workplace processes support the desired culture and strategy begins with the Board of Directors and the Office of the Chief Executive. The Talent and Compensation Committee (formerly Personnel Committee) establishes priorities and each quarter reviews strategies and results on a range of topics covering the workforce, the workplace, and the marketplace. It oversees Entergys incentive plan design and administers its executive compensation plans to incentivize the behaviors and outcomes that support achievement of Entergys corporate objectives. Annually, it reviews executive performance, development, succession plans, and talent pipeline to align a high performing executive team with Entergys priorities. The Talent and Compensation Committee also oversees Entergys performance through regular briefings on a wide variety of human resources topics including Entergys safety culture and performance; organizational health; and diversity, inclusion, and belonging initiatives and performance. The Talent and Compensation Committees Charter was revised in 2021 to acknowledge the committees responsibility for overseeing and monitoring the effectiveness of Entergys human capital strategies, including its workforce diversity, inclusion, and organizational health and safety strategies, programs, and initiatives. In recognition of the importance that organizational health and diversity, inclusion, and belonging play in enabling Entergy to achieve its business strategies, the committee receives periodic reports on Entergys organization health and diversity, inclusion, and belonging programs, strategies, and performance, including briefings at each of its regular meetings. The committee also receives updates on Entergys performance to date on key workforce, workplace, and marketplace measures, including progress in the representation of women and underrepresented minorities, both in the total workforce and in director level and above placements, progress in key diversity, inclusion, and belonging initiatives and diverse supplier spend. Other committees of the Board oversee other key aspects of Entergys culture. For example, the Audit Committee reviews reports on enterprise risks, ethics, and compliance training and performance, as well as regular reports on calls made to Entergys ethics line and related investigations. To maximize the sharing of information and facilitate the participation of all Board members in these discussions, the Board schedules its regular committee meetings in a manner such that all directors can attend. Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy The Office of the Chief Executive, which includes the Senior Vice President and Chief Human Resources Officer, ensures annual business plans are designed to support Entergys talent objectives, reviews workforce-related metrics, and regularly discusses the development, succession planning, and performance of their direct reports and other company officers. Safety Entergys safety objective is: Everyone Safe. All Day. Every Day. The continuation of the COVID-19 pandemic and another historic hurricane season presented significant challenges. Entergy employees achieved a total recordable incident rate of 0.51 in 2022, compared to 0.46 in 2021, and 0.40 in 2020. The results of 2021 unfortunately included an employee fatality. Entergy has enhanced dramatically leadership efforts and field presence to further its objective of zero fatalities, which it achieved in 2022. Also in 2022, there was a significant decrease in the number of serious injuries. The recordable incident rate equals the number of recordable incidents per 100 full-time equivalents. Recordable incidents include fatalities, lost-time accidents, restricted-duty accidents, and medical attentions and is not inclusive of potential work-related COVID-19 cases. Organizational Health, including Diversity, Inclusion and Belonging (DIB) Entergy believes that organizational health fosters an engaged and productive culture that positions Entergy to deliver sustainable value to its stakeholders. Entergy measures its progress through an organizational health survey coordinated by an external third party. Since initially administering the survey in 2014, Entergy improved from an initial score of 49 (fourth quartile) to a score in 2020 of 72 (second quartile), in 2021 of 63 (third quartile), and in 2022 of 61 (third quartile). Although the score declined slightly in 2022 as compared to 2021, it improved from the 2014 baseline. Management uses the results of the annual survey to design and implement strategies to positively influence organizational health. Initial employee participation of 66 percent in 2014 rose to and remains at approximately 90 percent in 2019-2022. Entergy believes that creating a culture of diversity, inclusion, and belonging drives foundational engagement. Entergy is committed to developing and retaining a workforce that reflects the rich diversity of the communities it serves. In 2019, Entergy embarked on a three-year phased approach to enhance inclusion for individuals and teams. In 2022, Entergy continued to focus its actions to engage a diverse workforce, infusing DIB into hiring policies, practices and procedures, aligning Employee Resource Group goals to DIB goals, growing its DIB Champion network, integrating DIB into Entergys leadership development programs, and facilitating training from the executive leadership ranks down to the frontline. Through these efforts, Entergy aspires to create greater understanding and accountability regarding the behaviors and outcomes that are indicative of a premier utility. Talent Management Entergys focus on talent management is organized in three areas: developing and attracting a diverse pool of talent, equipping its leaders to develop the organization, and building premier utility capability through employee performance management and succession programs. Entergy believes that developing a diverse pool of local talent equipped with the skills needed, today and in the future, and reflecting the communities Entergy serves will give it a long-term competitive advantage. The focus of Entergys leadership development programs is to equip managers with the skills needed to effectively develop their teams and improve the leader-employee relationship. Entergys talent development infrastructure, which includes a combination of business function-specific and enterprise-wide learning and development programs, is designed to ensure Entergy has qualified staff with the skills, experiences, and behaviors needed to perform today and prepare for the future. Entergy strives to achieve its strategic priorities by aligning and enhancing team and individual performance with business objectives, effectively deploying talent through succession planning, and managing workforce transitions. Part I Item 1 Entergy Corporation, Utility operating companies, and System Energy Availability of SEC filings and other information on Entergys website Entergy electronically files reports with the SEC, including annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxies, and amendments to such reports. The SEC maintains an internet site that contains reports, proxy and information statements, and other information regarding registrants that file electronically with the SEC at http://www.sec.gov. Copies of the reports that Entergy files with the SEC can be obtained at the SECs website. Entergy uses its website, http://www.entergy.com, as a routine channel for distribution of important information, including news releases, analyst presentations and financial information. Filings made with the SEC are posted and available without charge on Entergys website as soon as reasonably practicable after they are electronically filed with, or furnished to, the SEC. These filings include annual and quarterly reports on Forms 10-K and 10-Q and current reports on Form 8-K (including related filings in XBRL format); proxy statements; and any amendments to those reports or statements. All such postings and filings are available on Entergys Investor Relations website free of charge. Entergy is providing the address to its internet site solely for the information of investors and does not intend the address to be an active link. The contents of the website are not incorporated into this report. Part I Item 1A and 1B Entergy Corporation, Utility operating companies, and System Energy Item 1A. RISK FACTORS See RISK FACTORS SUMMARY in Part I Item 1 for a summary of Entergys and the Registrant Subsidiaries risk factors. Investors should review carefully the following risk factors and the other information in this Form 10-K. The risks that Entergy faces are not limited to those in this section. There may be additional risks and uncertainties (either currently unknown or not currently believed to be material) that could adversely affect Entergys financial condition, results of operations, and liquidity. See FORWARD-LOOKING INFORMATION . Utility Regulatory Risks (Entergy Corporation, Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, Entergy Texas, and System Energy) The terms and conditions of service, including electric and gas rates, of the Utility operating companies and System Energy are determined through regulatory approval proceedings that can be lengthy and subject to appeal, potentially resulting in delays in effecting rate changes, lengthy litigation, the risk of disallowance of recovery of certain costs, and uncertainty as to ultimate results. The Utility operating companies are regulated on a cost-of-service and rate of return basis and are subject to statutes and regulatory commission rules and procedures. The rates that the Utility operating companies and System Energy charge reflect their capital expenditures, operations and maintenance costs, allowed rates of return, financing costs, and related costs of service. These rates significantly influence the financial condition, results of operations, and liquidity of Entergy and each of the Utility operating companies and System Energy. These rates are determined in regulatory proceedings and are subject to periodic regulatory review and adjustment, including adjustment upon the initiative of a regulator or, in some cases, affected stakeholders. Regulators in a future rate proceeding may alter the timing or amount of certain costs for which recovery is allowed or modify the current authorized rate of return. Rate refunds may also be required, subject to applicable law. In addition, regulators have initiated and may initiate additional proceedings to investigate the prudence of costs in the Utility operating companies and System Energys base rates and examine, among other things, the reasonableness or prudence of the companies operation and maintenance practices, level of expenditures (including storm costs and costs associated with capital projects), allowed rates of return and rate base, proposed resource acquisitions, and previously incurred capital expenditures that the operating companies seek to place in rates. The regulators may disallow costs subject to their jurisdiction found not to have been prudently incurred or found not to have been incurred in compliance with applicable tariffs, creating some risk to the ultimate recovery of those costs. Regulatory proceedings relating to rates and other matters typically involve multiple parties seeking to limit or reduce rates. Traditional base rate proceedings, as opposed to formula rate plans, generally have long timelines, are primarily based on historical costs, and may or may not be limited in scope or duration by statute. The length of these base rate proceedings can cause the Utility operating companies and System Energy to experience regulatory lag in recovering costs through rates, such that the Utility operating companies may not fully recover all costs during the rate effective period and may, therefore, earn less than their allowed returns. Decisions are typically subject to appeal, potentially leading to additional uncertainty associated with rate case proceedings. For a discussion of such appeals and related litigation for both the Utility operating companies and System Energy, see Note 2 to the financial statements. The Utility operating companies have large customer and stakeholder bases and, as a result, could be the subject of public criticism or adverse publicity focused on issues including the operation and maintenance of their assets and infrastructure, their preparedness for major storms or other extreme weather events and/or the time it takes to restore service after such events, or the quality of their service or the reasonableness of the cost of their Part I Item 1A and 1B Entergy Corporation, Utility operating companies, and System Energy service. Criticism or adverse publicity of this nature could render legislatures and other governing bodies, public service commissions and other regulatory authorities, and government officials less likely to view the applicable operating company in a favorable light and could potentially negatively affect legislative or regulatory processes or outcomes, as well as lead to increased regulatory oversight or more stringent legislative or regulatory requirements or other legislation or regulatory actions that adversely affect the Utility operating companies. The Utility operating companies and System Energy, and the energy industry as a whole, have experienced a period of rising costs and investments and an upward trend in spending, especially with respect to infrastructure investments, which is likely to continue in the foreseeable future and could result in more frequent rate cases and requests for, and the continuation of, cost recovery mechanisms, all of which could face resistance from customers and other stakeholders especially in a rising cost environment, whether due to inflation or high fuel prices or otherwise, and/or in periods of economic decline or hardship. Significant increases in costs could increase financing needs and otherwise adversely affect Entergy, the Utility operating companies, and System Energys business, financial position, results of operation, or cash flows. For information regarding rate case proceedings and formula rate plans applicable to the Utility operating companies, see Note 2 to the financial statements. Changes to state or federal legislation or regulation affecting electric generation, electric and natural gas transmission, distribution, and related activities could adversely affect Entergy and the Utility operating companies financial position, results of operations, or cash flows and their utility businesses. If legislative and regulatory structures evolve in a manner that erodes the Utility operating companies exclusive rights to serve their regulated customers, they could lose customers and sales and their results of operations, financial position, or cash flows could be materially affected. Additionally, technological advances in energy efficiency and distributed energy resources are reducing the costs of these technologies and, together with ongoing state and federal subsidies, the increasing penetration of these technologies could result in reduced sales by the Utility operating companies. Such loss of sales, due to the methodology used to determine cost of service rates or otherwise, could put upward pressure on rates, possibly resulting in adverse regulatory actions to mitigate such effects on rates. Further, the failure of regulatory structures to evolve to accommodate the changing needs and desires of customers with respect to the sourcing and use of electricity also could diminish sales by the operating companies. Entergy and the Utility operating companies cannot predict if or when they may be subject to changes in legislation or regulation, or the extent and timing of reductions of the cost of distributed energy resources, nor can they predict the impact of these changes on their results of operations, financial position, or cash flows. The Utility operating companies recover fuel, purchased power, and associated costs through rate mechanisms that are subject to risks of delay or disallowance in regulatory proceedings, and sudden or prolonged increases in fuel and purchased power costs could lead to increased customer arrearages or bad debt expenses. The Utility operating companies recover their fuel, purchased power, and associated costs from their customers through rate mechanisms subject to periodic regulatory review and adjustment. Because regulatory review can result in the disallowance of incurred costs found not to have been prudently incurred or not reflected in rates as permitted by approved rate schedules and accounting rules, including the cost of replacement power purchased when generators experience outages or when planned outages are extended, with the possibility of refunds to ratepayers, there exists some risk to the ultimate recovery of those costs, particularly when there are substantial or sudden increases in such costs. Regulators also may initiate proceedings to investigate the continued usage or the adequacy and operation of the fuel and purchased power recovery clauses of the Utility operating companies and, therefore, there can be no assurance that existing recovery mechanisms will remain unchanged or in effect at all. The Utility operating companies cash flows can be negatively affected by the time delays between when gas, power, or other commodities are purchased and the ultimate recovery from customers of the costs in rates. On occasion, when the level of incurred costs for fuel and purchased power rises very dramatically, some Part I Item 1A and 1B Entergy Corporation, Utility operating companies, and System Energy of the Utility operating companies may agree to defer recovery of a portion of that periods fuel and purchased power costs for recovery at a later date, which could increase the near-term working capital and borrowing requirements of those companies. The Utility operating companies also may experience, and in some instances have experienced, an increase in customer bill arrearages and bad debt expenses due to, among other reasons, increases in fuel and purchased power costs, especially in periods of economic decline or hardship. For a description of fuel and purchased power recovery mechanisms and information regarding the regulatory proceedings for fuel and purchased power cost recovery, see Note 2 to the financial statements. The Utility operating companies are subject to economic risks associated with participation in the MISO markets and the allocation of transmission upgrade costs. The operation of the Utility operating companies transmission system pursuant to the MISO RTO tariff and their participation in the MISO RTOs wholesale markets may be adversely affected by regulatory or market design changes, as well as liability under, or any future inability to comply with, existing or future regulations or requirements. On December 19, 2013, the Utility operating companies integrated into the MISO RTO. MISO maintains functional control over the combined transmission systems of its members and administers wholesale energy and ancillary services markets for market participants in the MISO region, including the Utility operating companies. The Utility operating companies sell capacity, energy, and ancillary services on a bilateral basis to certain wholesale customers and offer available electricity production of their owned and controlled generating facilities into the MISO resource adequacy construct (the annual Planning Resource Auction, discussed below), as well as the day-ahead and real-time energy markets pursuant to the MISO tariff and market rules. The Utility operating companies are subject to economic risks associated with participation in the MISO markets and resource adequacy construct. MISO tariff rules and system conditions, including transmission congestion, could affect the Utility operating companies ability to sell capacity, energy, and/or ancillary services in certain regions and/or the economic value of such sales, or the cost of serving the Utility operating companies respective loads. MISO market rules may change or be interpreted in ways that cause additional cost and risk, including compliance risk. The Utility operating companies participate in the MISO regional transmission planning process and are subject to risks associated with planning decisions that MISO makes in the exercise of control over the planning of the Utility operating companies transmission assets that are under MISOs functional control. The Utility operating companies pay transmission rates that reflect the cost of transmission projects that the Utility operating companies do not own, which could increase cash or financing needs. Further, FERC policies and regulation addressing cost responsibility for transmission projects, including transmission projects to interconnect new generation facilities, may potentially give rise to cash and financing-related risks as well as result in upward pressure on the retail rates of the Utility operating companies, which, in turn, may result in adverse actions by the Utility operating companies retail regulators. In addition to the cash and financing-related risks arising from the potential additional cost allocation to the Utility operating companies from transmission projects of others or changes in FERC policies or regulation related to cost responsibility for transmission projects, there is a risk that the Utility operating companies business and financial position could be harmed as a result of lost investment opportunities and other effects that flow from an increased number of competitive projects being approved and constructed that are interconnected with their transmission systems. Further, the terms and conditions of the MISO tariff, including provisions related to the design and implementation of wholesale markets, the allocation of transmission upgrade costs, the MISO-wide allowed base rate of return on equity, and any required MISO-related charges and credits are subject to regulation by the FERC. The operation of the Utility operating companies transmission system pursuant to the MISO tariff and their participation in the MISO wholesale markets, and the resulting costs, may be adversely affected by regulatory or market design changes, as well as liability under, or any future inability to comply with, existing or future regulations or requirements. Moreover, the resource adequacy construct provided under the MISO tariff confers certain rights and imposes certain obligations upon load-serving entities, including the Utility operating companies, that are served Part I Item 1A and 1B Entergy Corporation, Utility operating companies, and System Energy from the transmission systems subject to MISOs functional control, including the transmission facilities of the Utility operating companies. The MISO tariff provisions governing these rights and obligations are subject to change and have recently undergone significant changes, some of which are the subject of pending litigation and/or appeals. Due to their magnitude and the speed with which they have been implemented, these changes carry risk, including compliance risk, and may result in material additional costs being passed through to the Utility operating companies customers in retail rates, including but not limited to additional capacity costs incurred in the annual MISO Planning Resource Auction. Also, by virtue of the Utility operating companies participation in MISO and the design and terms of the MISO resource adequacy construct, other load-serving entities served by the Utility operating companies transmission assets, which are under MISOs functional control, may be able to circumvent reasonable resource planning obligations and avoid, in whole or in part, the full cost of procuring the resources reasonably needed to reliably supply their respective loads. In particular, the design of the current MISO resource adequacy construct and the absence of a minimum capacity obligation in MISO create a risk of other load-serving entities engaging in free ridership through their strategy for participation in the MISO resource adequacy construct and energy and ancillary services markets specifically, by using energy and ancillary services available from the Utility operating companies owned and controlled generating units without paying a reasonable share of the cost of the capacity required to provide such energy and ancillary services. As a result, there are a variety of risks to the Utility operating companies and their customers, including the risk of bearing additional costs for resources needed to ensure reliable service, the risk of reduced reliability and the enhanced risk of outages and lost sales which, because of the methodology for establishing cost of service rates, presents the risk of upward pressure on the Utility operating companies rates. In addition, orders from each of the Utility operating companies respective retail regulators generally require that the Utility operating companies make periodic filings, or generally allow the retail regulator to direct the making of such filings, setting forth the results of analysis of the costs and benefits realized from MISO membership as well as the projected costs and benefits of continued membership in MISO and/or requesting approval of their continued membership in MISO. These filings have been submitted periodically by each of the Utility operating companies as required by their respective retail regulators, and the outcome of the resulting proceedings may affect the Utility operating companies continued membership in MISO. The continued impacts of the COVID-19 pandemic and responsive measures taken on Entergys and its Utility operating companies business, results of operations, and financial condition are highly uncertain and cannot be predicted. The global 2019 novel coronavirus pandemic continues to be an evolving situation and could lead to further disruption of the general economy, impacts on the customers of Entergys Utility operating companies, and disruption of the operations of Entergys subsidiaries, whether due to, among other things, the emergence or spread of new variants of COVID-19, precautionary or reactionary measures, market reactions or impacts, or supply chain constraints. Entergy and its Utility operating companies experienced an increase in arrearages and bad debt expense due to non-payment by customers. The arrearages due to COVID-19 have begun to decline, although management cannot predict the timing of the completion of collections of such arrearages. While the Utility operating companies are working with regulators to ensure ultimate recovery for those and other COVID-19 related costs, the amount, method, and timing of such recovery is subject to approval by the retail regulators. Entergy and its Registrant Subsidiaries also could experience, and in some cases have experienced, among other challenges that originated during or have been exacerbated by the COVID-19 pandemic: supply chain, vendor, and contractor disruptions, including shortages or delays in the availability of key components, parts, and supplies such as electronic components and solar panels; delays in completion of capital or other construction projects, maintenance, and other operations activities, including prolonged or delayed refueling and maintenance outages; delays in regulatory proceedings; workforce availability challenges, including from COVID-19 infections, health, or safety issues; increased storm recovery costs; increased cybersecurity risks as a result of many employees Part I Item 1A and 1B Entergy Corporation, Utility operating companies, and System Energy telecommuting; volatility in the credit or capital markets (and any related increased cost of capital or any inability to access the capital markets or draw on available credit facilities); or other adverse impacts on their ability to execute on business strategies and initiatives. Although the economy has been recovering, another economic decline could adversely impact Entergys and the Utility operating companies liquidity and cash flows, including through declining sales, reduced revenues, delays in receipts of customer payments, or increased bad debt expense. The Utility operating companies also may experience regulatory outcomes that require them to postpone planned investment and otherwise reduce costs due to the impact of the COVID-19 pandemic on their customers, especially in an environment of higher inflation. In addition, if the COVID-19 pandemic or related impacts create additional disruptions or turmoil in the credit or financial markets, or adversely impact Entergys credit metrics or ratings, such developments could adversely affect its ability to access capital on favorable terms and continue to meet its liquidity needs or cause a decrease in the value of its defined benefit pension trust funds, as well as its nuclear decommissioning trust funds, all of which are highly uncertain and cannot be predicted. Entergy cannot predict the extent or duration of the ongoing COVID-19 pandemic, the impact of new or existing variants of COVID-19, the effectiveness of mitigation efforts, further governmental responsive measures, or the extent of the effects or ultimate impacts on the global, national or local economy, the capital markets, or its customers, suppliers, operations, financial condition, results of operations, or cash flows. (Entergy Corporation, Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, and Entergy Texas) A delay or failure in recovering amounts for storm restoration costs incurred as a result of severe weather, the impact on customer bills of permitted storm cost recovery, or the inability to securitize future storm restoration costs could have material effects on Entergy and its Utility operating companies. Entergys and its Utility operating companies results of operations, liquidity, and financial condition can be materially affected by the destructive effects of severe weather. Severe weather can also result in significant outages for the customers of the Utility operating companies and, therefore, reduced revenues for the Utility operating companies during the period of the outages. A delay or failure in recovering amounts for storm restoration costs incurred, inability to securitize future storm restoration costs, or loss of revenues as a result of severe weather could have a material effect on Entergy and those Utility operating companies affected by severe weather, including lower credit ratings and, thus, higher costs for future debt issuances. The inability to recover losses either excluded by insurance or in excess of the insurance limits that can be secured economically also could have a material effect on Entergy and its Utility operating companies. In addition, the recovery of major storm restoration costs from customers could effectively limit our ability to make planned capital or other investments due to the impact of such storm cost recovery on customer bills, especially in a rising cost environment. In August 2021, Hurricane Ida caused extensive damage to the Entergy distribution and, to a lesser extent, transmission systems across Louisiana, resulting in storm costs of $2.5 billion. Entergy Louisiana began recovering a portion of these costs through securitization financings in 2022. In January 2023 the LPSC issued orders finding prudent the costs incurred by Entergy Louisiana in responding to Hurricane Ida and allowing Entergy Louisiana to securitize the remaining $1.491 billion in such costs. Because such orders are not yet final and non-appealable (due to the forty-five day appeal period) and, further, because the bond rating and marketing process has yet to occur, there is an element of risk, and Entergy Louisiana is unable to predict with certainty the ultimate success of its recovery initiatives or the timing of such recovery. Part I Item 1A and 1B Entergy Corporation, Utility operating companies, and System Energy Weather, economic conditions, technological developments, and other factors may have a material impact on electricity and gas sales and otherwise materially affect the Utility operating companies results of operations and system reliability.

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Temperatures above normal levels in the summer tend to increase electric cooling demand and revenues, and temperatures below normal levels in the winter tend to increase electric and gas heating demand and revenues. As a corollary, mild temperatures in either season tend to decrease energy usage and resulting revenues. Higher consumption levels coupled with seasonal pricing differentials typically cause the Utility operating companies to report higher revenues in the third quarter of the fiscal year than in the other quarters. Changing weather patterns and extreme weather conditions, including hurricanes or tropical storms, flooding events, or ice storms, the frequency or intensity of which may be exacerbated by climate change, may stress the Utility operating companies generation facilities and transmission and distribution systems, resulting in increased maintenance and capital costs (and potential increased financing needs), limits on their ability to meet peak customer demand, increased regulatory oversight, criticism or adverse publicity, and reduced customer satisfaction. These extreme conditions could have a material effect on the Utility operating companies financial condition, results of operations, and liquidity. Entergys electricity sales volumes are affected by a number of factors including weather and economic conditions, trends in energy efficiency, new technologies, and self-generation alternatives, including the willingness and ability of large industrial customers to develop co-generation facilities that greatly reduce their grid demand. In addition, changes to regulatory policies, such as those that allow customers to directly access the market to procure wholesale energy or those that incentivize development and utilization of new, developing, or alternative sources of generation, could, and in some instances, have reduced sales, and other non-traditional procurements, such as virtual purchase power agreements, could, and in some instances have limited growth opportunities or reduced sales at the Utility operating companies. Some of these factors are inherently cyclical or temporary in nature, such as the weather or economic conditions, and rarely have a long-lasting effect on Entergys operating results. Others, such as the organic turnover of appliances and lighting and their replacement with more efficient ones and adoption of newer technologies, including smart thermostats, new building codes, distributed energy resources, energy storage, demand side management, and rooftop solar, are having a more permanent effect by reducing sales growth rates from historical norms. As a result of these emerging efficiencies and technologies, the Utility operating companies may lose customers or experience lower average use per customer in the residential and commercial classes, and continuing advances have the potential to further limit sales or sales growth in the future. The Utility operating companies also may face competition from other companies offering products and services to Entergys customers. Electricity sales to industrial customers, in particular, benefit from steady economic growth and favorable commodity markets; however, industrial sales are sensitive to changes in conditions in the markets in which its customers operate. Negative changes in any of these or other factors, particularly sustained economic downturns or sluggishness, have the potential to result in slower sales growth or sales declines and increased bad debt expense, which could materially affect Entergys and the Utility operating companies results of operations, financial condition, and liquidity. The Utility operating companies also may not realize anticipated or expected growth in industrial sales from electrification opportunities to help such customers achieve their environmental and sustainability goals. This could occur because of changes in customers goals or business priorities, competition from other companies, or decisions by such customers to seek to achieve such goals through methods not offered by Entergy. Part I Item 1A and 1B Entergy Corporation, Utility operating companies, and System Energy Nuclear Operating, Shutdown, and Regulatory Risks (Entergy Corporation, Entergy Arkansas, Entergy Louisiana, and System Energy) Certain of the Utility operating companies and System Energy are expected to consistently operate their nuclear power plants at high capacity factors in order to be successful, and lower capacity factors could materially affect Entergys and their results of operations, financial condition, and liquidity. Nuclear capacity factors significantly affect the results of operations of certain Utility operating companies and System Energy. Nuclear plant operations involve substantial fixed operating costs. Consequently, there is pressure on plant owners to operate nuclear power plants at higher capacity factors, though such operations always must be consistent with safety, reliability, and nuclear regulatory requirements. For the Utility operating companies that own nuclear plants, lower nuclear plant capacity factors can increase production costs by requiring the affected companies to generate additional energy, sometimes at higher costs, from their owned or contractually controlled facilities or purchase additional energy in the spot or forward markets in order to satisfy their supply needs. Certain of the Utility operating companies and System Energy periodically shut down their nuclear power plants to replenish fuel. Plant maintenance and upgrades are often scheduled during such refueling outages. If refueling outages last longer than anticipated or if unplanned outages arise, Entergys and their results of operations, financial condition, and liquidity could be materially affected. Outages at nuclear power plants to replenish fuel require the plant to be turned off. Refueling outages generally are planned to occur once every 18 to 24 months. Plant maintenance and upgrades are often scheduled during such planned outages, which may extend the planned outage duration beyond that required for only refueling activities. When refueling outages last longer than anticipated or a plant experiences unplanned outages, capacity factors decrease, and maintenance costs may increase. Certain of the Utility operating companies and System Energy face risks related to the purchase of uranium fuel (and its conversion, enrichment, and fabrication). These risks could materially affect Entergys and their results of operations, financial condition, and liquidity. Based upon currently planned fuel cycles, Entergys nuclear units have a diversified portfolio of contracts and inventory that provides substantially adequate nuclear fuel materials and conversion and enrichment services at what Entergy believes are reasonably predictable prices through most of 2027. Entergys ability to purchase nuclear fuel at reasonably predictable prices, however, depends upon the performance reliability of uranium miners. While there are a number of possible alternate suppliers that may be accessed to mitigate any supplier performance failure, the pricing of any such alternate uranium supply from the market will be dependent upon the market for uranium supply at that time. Entergy buys uranium from a diversified mix of sellers located in a diversified mix of countries, and from time to time purchases from nearly all qualified reliable major market participants worldwide that sell into the U.S. Market prices for nuclear fuel have been extremely volatile from time to time in the past and may be subject to increased volatility due to the imposition of tariffs, domestic purchase requirements or limitations on importation of uranium or uranium products from foreign countries, geopolitical conditions, or shifting trade arrangements between countries. Although Entergys nuclear fuel contract portfolio provides a degree of hedging against market risks for several years, costs for nuclear fuel in the future cannot be predicted with certainty due to normal inherent market uncertainties, and price changes could materially affect the liquidity, financial condition, and results of operations of certain of the Utility operating companies and System Energy. Entergys ability to assure nuclear fuel supply also depends upon the performance and reliability of conversion, enrichment, and fabrication services providers. These service providers are fewer in number than uranium suppliers. For conversion and enrichment services, Entergy diversifies its supply by supplier and country and may take special measures to ensure a reliable supply of enriched uranium for fabrication into nuclear fuel. For fabrication services, each plant is dependent upon the performance of the fabricator of that plants nuclear fuel; Part I Item 1A and 1B Entergy Corporation, Utility operating companies, and System Energy therefore, Entergy relies upon additional monitoring, inspection, and oversight of the fabrication process to assure reliability and quality of its nuclear fuel. Certain of the suppliers and service providers are located in or dependent upon foreign countries, such as Russia, and international sanctions or tariffs impacting trade with such countries could further restrict the ability of such suppliers or service providers to continue to supply fuel or provide such services at acceptable prices or at all. The inability of such suppliers or service providers to perform such obligations could materially affect the liquidity, financial condition, and results of operations of certain of the Utility operating companies and System Energy. Certain of the Utility operating companies and System Energy face the risk that the NRC will change or modify its regulations, suspend or revoke their licenses, or increase oversight of their nuclear plants, which could materially affect Entergys and their results of operations, financial condition, and liquidity. Under the Atomic Energy Act and Energy Reorganization Act, the NRC regulates the operation of nuclear power plants. The NRC may modify, suspend, or revoke licenses, shut down a nuclear facility and impose civil penalties for failure to comply with the Atomic Energy Act, related regulations, or the terms of the licenses for nuclear facilities. Interested parties may also intervene which could result in prolonged proceedings. A change in the Atomic Energy Act, other applicable statutes, or the applicable regulations or licenses, or the NRCs interpretation thereof, may require a substantial increase in capital expenditures or may result in increased operating or decommissioning costs and could materially affect the results of operations, liquidity, or financial condition of Entergy, certain of the Utility operating companies, or System

Energy. A change in the classification of a plant owned by one of these companies under the NRCs Reactor Oversight Process, which is the NRCs program to collect information about plant performance, assess the information for its safety significance, and provide for appropriate licensee and NRC response, also could cause the owner of the plant to incur material additional costs as a result of the increased oversight activity and potential response costs associated with the change in classification. For additional information concerning the current classification of the plants owned by Entergy Arkansas, Entergy Louisiana, and System Energy, see Regulation of Entergys Business - Regulation of the Nuclear Power Industry - NRC Reactor Oversight Process in Part I, Item 1. Events at nuclear plants owned by one of these companies, as well as those owned by others, may lead to a change in laws or regulations or the terms of the applicable licenses, or the NRCs interpretation thereof, or may cause the NRC to increase oversight activity or initiate actions to modify, suspend, or revoke licenses, shut down a nuclear facility, or impose civil penalties. As a result, if an incident were to occur at any nuclear generating unit, whether an Entergy nuclear generating unit or not, it could materially affect the financial condition, results of operations, and liquidity of Entergy, certain of the Utility operating companies, or System Energy. Certain of the Utility operating companies and System Energy are exposed to risks and costs related to operating and maintaining their nuclear power plants, and their failure to maintain operational efficiency at their nuclear power plants could materially affect Entergys and their results of operations, financial condition, and liquidity. The nuclear generating units owned by certain of the Utility operating companies and System Energy began commercial operations in the 1970s-1980s. Older equipment may require more capital expenditures to keep each of these nuclear power plants operating safely and efficiently. This equipment is also likely to require periodic upgrading and improvement. Any unexpected failure, including failure associated with breakdowns, forced outages, or any unanticipated capital expenditures, could result in increased costs, some of which costs may not be fully recoverable by these Utility operating companies and System Energy in regulatory proceedings should there be a determination of imprudence. Operations at any of the nuclear generating units owned and operated by Entergys subsidiaries could degrade to the point where the affected unit needs to be shut down or operated at less than full capacity. If this were to happen, identifying and correcting the causes may require significant time and expense. A decision may be made to close a unit rather than incur the expense of restarting it or returning the unit to full capacity. For these Utility operating companies and System Energy, this could result in certain costs being stranded Part I Item 1A and 1B Entergy Corporation, Utility operating companies, and System Energy and potentially not fully recoverable in regulatory proceedings. In addition, the operation and maintenance of Entergys nuclear facilities require the commitment of substantial human resources that can result in increased costs. Moreover, Entergy is becoming more dependent on fewer suppliers for key parts of Entergys nuclear power plants that may need to be replaced or refurbished, and in some cases, parts are no longer available and have to be reverse-engineered for replacement. In addition, certain major parts have long lead-times to manufacture if an unplanned replacement is needed. This dependence on a reduced number of suppliers and long lead-times on certain major parts for unplanned replacements could result in delays in obtaining qualified replacement parts and, therefore, greater expense for Entergy, certain of the Utility operating companies, and System Energy. The costs associated with the storage of the spent nuclear fuel of certain of the Utility operating companies and System Energy, as well as the costs of and their ability to fully decommission their nuclear power plants, could be significantly affected by the timing of the opening of a spent nuclear fuel disposal facility, as well as interim storage and transportation requirements. Certain of the Utility operating companies and System Energy incur costs for the on-site storage of spent nuclear fuel. The approval of a license for a national repository for the disposal of spent nuclear fuel, such as the one proposed for Yucca Mountain, Nevada, or any interim storage facility, and the timing of such facility opening, will significantly affect the costs associated with on-site storage of spent nuclear fuel. For example, while the DOE is required by law to proceed with the licensing of Yucca Mountain and, after the license is granted by the NRC, to construct the repository and commence the receipt of spent fuel, the NRC licensing of the Yucca Mountain repository is effectively at a standstill. These actions are prolonging the time before spent fuel is removed from Entergys plant sites. Because the DOE has not accomplished its objectives, it is in non-compliance with the Nuclear Waste Policy Act of 1982 and has breached its spent fuel disposal contracts, and Entergy has sued the DOE for such breach. Furthermore, Entergy is uncertain as to when the DOE will commence acceptance of spent fuel from its facilities for storage or disposal. As a result, continuing future expenditures will be required to increase spent fuel storage capacity at the companies nuclear sites and maintenance costs on existing storage facilities, including aging management of fuel storage casks, may increase. The costs of on-site storage are also affected by regulatory requirements for such storage. In addition, the availability of a repository or other off-site storage facility for spent nuclear fuel may affect the ability to fully decommission the nuclear units and the costs relating to decommissioning. For further information regarding spent fuel storage, see the Critical Accounting Estimates Nuclear Decommissioning Costs Spent Fuel Disposal section of Managements Financial Discussion and Analysis for Entergy, Entergy Arkansas, Entergy Louisiana, and System Energy and Note 8 to the financial statements. Certain of the Utility operating companies and System Energy may be required to pay substantial retrospective premiums imposed under the Price-Anderson Act and/or by Nuclear Electric Insurance Limited (NEIL) in the event of a nuclear incident, and losses not covered by insurance could have a material effect on Entergys and their results of operations, financial condition, or liquidity. Accidents and other unforeseen problems at nuclear power plants have occurred both in the United States and elsewhere. As required by the Price-Anderson Act, the Utility operating companies and System Energy carry the maximum available amount of primary nuclear off-site liability insurance with American Nuclear Insurers, which is $450 million for each operating site. Claims for any nuclear incident exceeding that amount are covered under Secondary Financial Protection. The Price-Anderson Act limits each reactor owners public liability (off-site) for a single nuclear incident to the payment of retrospective premiums into a secondary insurance pool, which is referred to as Secondary Financial Protection, up to approximately $137.6 million per reactor. With 96 reactors currently participating, this translates to a total public liability cap of approximately $13 billion per incident. The limit is subject to change to account for the effects of inflation, a change in the primary limit of insurance coverage, and changes in the number of licensed reactors. As a result, in the event of a nuclear incident that causes damages (off-site) in excess of the primary insurance coverage, each owner of a nuclear plant reactor, including Entergys Utility operating companies and System Energy, regardless of fault or proximity to the incident, will be required to Part I Item 1A and 1B Entergy Corporation, Utility operating companies, and System Energy pay a retrospective premium, equal to its proportionate share of the loss in excess of the primary insurance level, up to a maximum of approximately $137.6 million per reactor per incident (Entergys maximum total contingent obligation per incident is $688 million). The retrospective premium payment is currently limited to approximately $21 million per year per incident per reactor until the aggregate public liability for each licensee is paid up to the $137.6 million cap. NEIL is a utility industry mutual insurance company, owned by its members, including the Utility operating companies and System Energy. NEIL provides onsite property and decontamination coverage. All member plants could be subject to an annual assessment (retrospective premium of up to 10 times current annual premium for all policies) should the NEIL surplus (reserve) be significantly depleted due to insured losses. As of January 1, 2023, the maximum annual assessment amounts total approximately $70 million for the Utility plants. Retrospective premium insurance available through NEILs reinsurance treaty can cover the potential assessments. As mentioned above, as an owner of nuclear power plants, Entergy participates in industry self-insurance programs and could be liable to fund claims should a plant owned by a different company experience a major event. Any resulting liability from a nuclear accident may exceed the applicable primary insurance coverage and require contribution of additional funds through the industry-wide program that could significantly affect the results of operations, financial condition, or liquidity of Entergy, certain of the Utility operating companies, or System Energy. The decommissioning trust fund assets for the nuclear power plants owned by certain of the Utility operating companies and System Energy may not be adequate to meet decommissioning obligations if market performance and other changes decrease the value of assets in the decommissioning trusts, if one or more of Entergys nuclear power plants is retired earlier than the anticipated shutdown date, if the plants cost more to decommission than estimated, or if current regulatory requirements change, which then could require significant additional funding. Owners of nuclear generating plants have an obligation to decommission those plants. Certain of the Utility operating companies and System Energy maintain decommissioning trust funds for this purpose. Certain of the Utility operating companies and System Energy collect funds from their customers, which are deposited into the trusts covering the units operated for or on behalf of those companies. Those rate collections, as adjusted from time to time by rate regulators, are generally based upon operating license lives and trust fund balances as well as estimated trust fund earnings and decommissioning costs. Assets in these trust funds are subject to market fluctuations, will yield uncertain returns that may fall below projected return rates, and may result in losses resulting from the recognition of impairments of the value of certain securities held in these trust funds. Under NRC regulations, nuclear plant owners are permitted to project the NRC-required decommissioning amount, based on an NRC formula or a site-specific estimate, and the amount that will be available in each nuclear power plants decommissioning trusts combined with any other decommissioning financial assurances in place. The projections are made based on the operating license expiration date and the mid-point of the subsequent decommissioning process, or the anticipated actual completion of decommissioning if a site-specific estimate is used. If the projected amount of each individual plants decommissioning trusts exceeds the NRC-required decommissioning amount, then its NRC license termination decommissioning obligations are considered to be funded in accordance with NRC regulations. If the projected costs do not sufficiently reflect the actual costs required to decommission these nuclear power plants, or funding is otherwise inadequate, or if the formula, formula inputs, or site-specific estimate is changed to require increased funding, additional resources or commitments would be required. Furthermore, depending upon the level of funding available in the trust funds, the NRC may not permit the trust funds to be used to pay for related costs such as the management of spent nuclear fuel that are not included in the NRCs formula. The NRC may also require a plan for the provision of separate funding for spent fuel management costs. Part I Item 1A and 1B Entergy Corporation, Utility operating companies, and System Energy Further, federal or state regulatory changes, including mandated increases in decommissioning funding or changes in the methods or standards for decommissioning operations, may also increase the funding requirements of, or accelerate the timing for funding of, the obligations related to the decommissioning of the nuclear generating plant owned by certain of the Utility operating companies or System Energy or may restrict the decommissioning-related costs that can be paid from the decommissioning trusts. Such changes also could result in the need for additional contributions to decommissioning trusts, or the posting of parent guarantees, letters of credit, or other surety mechanisms. As a result, under any of these circumstances, the results of operations, liquidity, and financial condition of Entergy, certain of the Utility operating companies, or System Energy could be materially affected. An early plant shutdown (either generally or relative to current expectations), poor investment results, or higher than anticipated decommissioning costs (including as a result of changing regulatory requirements) could cause trust fund assets to be insufficient to meet the decommissioning obligations, with the result that certain of the Utility operating companies or System Energy may be required to provide significant additional funds or credit support to satisfy regulatory requirements for decommissioning, which, with respect to these Utility operating companies or System Energy, may not be recoverable from customers in a timely fashion or at all. For further information regarding nuclear decommissioning costs, managements decision to exit the merchant power business, and the impairment charges that resulted from such decision, see the Critical Accounting Estimates - Nuclear Decommissioning Costs section of Managements Financial Discussion and Analysis for Entergy, Entergy Arkansas, Entergy Louisiana, and System Energy, the Entergy Wholesale Commodities Exit from the Merchant Power Business section of Managements Financial Discussion and Analysis for Entergy Corporation and Subsidiaries, and Notes 9, 14, and 16 to the financial statements. New or existing safety concerns regarding operating nuclear power plants and nuclear fuel could lead to restrictions upon the operation and decommissioning of Entergys nuclear power plants. New and existing concerns are being expressed in public forums about the safety of nuclear generating units and nuclear fuel. These concerns have led to, and may continue to lead to, various proposals to federal regulators and governing bodies in some localities where Entergys subsidiaries own nuclear generating units for legislative and regulatory changes that might lead to the shutdown of nuclear units, additional requirements or restrictions related to spent nuclear fuel on-site storage and eventual disposal, or other adverse effects on owning, operating, and decommissioning nuclear generating units. Entergy vigorously responds to these concerns and proposals. If any of the existing proposals, or any proposals that may arise in the future with respect to legislative and regulatory changes, become effective, they could have a material effect on Entergys results of operations and financial condition. General Business (Entergy Corporation, Entergy Arkansas, Entergy Louisiana, Entergy Mississippi, Entergy New Orleans, Entergy Texas, and System Energy) Entergy and its Registrant Subsidiaries depend on access to the capital markets and, at times, may face potential liquidity constraints, which could make it more difficult to handle future contingencies such as natural disasters or substantial increases in gas and fuel prices. Disruptions in the capital and credit markets may adversely affect Entergys and its subsidiaries ability to meet liquidity needs, access capital and operate and grow their businesses, and the cost of capital. Entergys business is capital intensive and dependent upon its ability to access capital at reasonable rates and other terms. At times there are also spikes in the price for natural gas and other commodities that increase the liquidity requirements of the Utility operating companies. In addition, Entergys and the Registrant Subsidiaries liquidity needs could significantly increase in the event of a hurricane or other weather-related or unforeseen disaster similar to that experienced in Entergys service area with Hurricane Katrina and Hurricane Rita in 2005, Part I Item 1A and 1B Entergy Corporation, Utility operating companies, and System Energy Hurricane Gustav and Hurricane Ike in 2008, Hurricane Isaac in 2012, Hurricane Laura, Hurricane Delta, and Hurricane Zeta in 2020, and Winter Storm Uri and Hurricane Ida in 2021. The occurrence of one or more contingencies, including an adverse decision or a delay in regulatory recovery of fuel or purchased power costs or storm restoration costs, an acceleration of payments or decreased credit lines, less cash flow from operations than expected, changes in regulation or governmental policy (including tax and trade policy), or other unknown events, could cause the financing needs of Entergy and its subsidiaries to increase. In addition, accessing the debt capital markets more frequently in these situations may result in an increase in leverage. Material leverage increases could negatively affect the credit ratings of Entergy, the Utility operating companies, and System Energy, which in turn could negatively affect access to the capital markets. The inability to raise capital on favorable terms, particularly during times of high interest rates, and uncertainty or reduced liquidity in the capital markets, could negatively affect Entergy and its subsidiaries ability to maintain and to expand their businesses. Access to capital markets could be restricted and/or borrowing costs could be increased due to certain sources of debt and equity capital being unwilling to invest in offerings to fund fossil fuel projects or companies that are impacted by extreme weather events, that rely on fossil fuels, or that are impacted by risks related to climate change. Factors beyond Entergys control may create uncertainty that could increase its cost of capital or impair its ability to access the capital markets, including the ability to draw on its bank credit facilities. These factors include depressed economic conditions, a recession, increasing interest rates, inflation, sanctions, trade restrictions, political instability, war, terrorism, and extreme volatility in the debt, equity, or credit markets. Entergy and its subsidiaries are unable to predict the degree of success they will have in renewing or replacing their credit facilities as they come up for renewal. Moreover, the size, terms, and covenants of any new credit facilities may not be comparable to, and may be more restrictive than, existing facilities. If Entergy and its subsidiaries are unable to access the credit and capital markets on terms that are reasonable, they may have to delay raising capital, issue shorter-term securities, and/or bear an unfavorable cost of capital, which, in turn, could impact their ability to grow their businesses, decrease earnings, significantly reduce financial flexibility, and/or limit Entergy Corporations ability to sustain its current common stock dividend level. A downgrade in Entergys or its Registrant Subsidiaries credit ratings could negatively affect Entergys and its Registrant Subsidiaries ability to access capital or the cost of such capital and/or could require Entergy or its subsidiaries to post collateral, accelerate certain payments, or repay certain indebtedness. There are a number of factors that rating agencies evaluate to arrive at credit ratings for each of Entergy and the Registrant Subsidiaries, including each Registrant Subsidiarys regulatory framework, ability to recover costs and earn returns, storm risk exposure, diversification, and financial strength and liquidity. If one or more rating agencies downgrade Entergys or any of the Registrant Subsidiaries ratings, particularly below investment grade, borrowing costs would increase, the potential pool of investors and funding sources would likely decrease, and cash or letter of credit collateral demands may be triggered by the terms of a number of commodity contracts, leases, and other agreements. Most of Entergys and its subsidiaries suppliers and counterparties require sufficient creditworthiness to enter into transactions. If Entergys or the Registrant

Subsidiaries ratings decline, particularly below investment grade, or if certain counterparties believe Entergy or the Utility operating companies are losing creditworthiness and demand adequate assurance under fuel, gas, and purchased power contracts, the counterparties may require posting of collateral in cash or letters of credit, prepayment for fuel, gas or purchased power or accelerated payment, or counterparties may decline business with Entergy or its subsidiaries. Entergy or its Registrant Subsidiaries may be materially adversely affected by negative publicity or the inability to meet its stated goals or commitments, among other potential causes. As with any company, Entergys and its Registrant Subsidiaries reputations are an important element of their ability to effectively conduct their business. Entergys and its Registrant Subsidiaries reputations could be harmed by a variety of factors, including: failure of a generating asset or supporting infrastructure; failure to restore Part I Item 1A and 1B Entergy Corporation, Utility operating companies, and System Energy power after a hurricane or other severe weather event in a manner perceived as timely by regulators or customers; the incurrence of storm restoration costs perceived as excessive by regulators or customers; failure to effectively manage land and other natural resources; real or perceived violations of environmental regulations, including those related to climate change; real or perceived issues with Entergys safety culture or work environment; inability to meet their climate or human capital strategy goals; inability to keep their electricity rates stable; involvement in a class-action or other high-profile lawsuit; significant delays in construction projects; occurrence of or responses to cyber attacks or security vulnerabilities; acts or omissions of Entergy management or acts or omissions of a contractor or other third-party working with or for Entergy or its Registrant Subsidiaries, which actually or perceivably reflect negatively on Entergy or its Registrant Subsidiaries; measures taken to offset reductions in demand or to supply rising demand; a significant dispute with one of Entergys or its Registrant Subsidiaries customers or other stakeholders; or negative political and public sentiment resulting in a significant amount of adverse press coverage and other adverse statements affecting Entergy or its Registrant Subsidiaries. Addressing any adverse publicity or regulatory scrutiny is time consuming and expensive and, regardless of the factual basis for the assertions being made (or lack thereof), can have a negative impact on the reputations of Entergy or its Registrant Subsidiaries, on the morale and performance of their employees, and on their relationships with their respective regulators, customers, and commercial counterparties. Adverse publicity or regulatory scrutiny may also have a negative impact on Entergy or its Registrant Subsidiaries ability to take timely advantage of various business or market opportunities. Deterioration in Entergys or its Registrant Subsidiaries reputations may harm Entergys or its Registrant Subsidiaries relationships with their customers, regulators, and other stakeholders, may increase their cost of doing business, may interfere with its ability to attract and retain a qualified, inclusive, and diverse workforce, may impact Entergys or its Registrant Subsidiaries ability to raise debt capital, and may potentially lead to the enactment of new laws and regulations, or the modification of existing laws and regulations, that negatively affect the way Entergy or its Registrant Subsidiaries conduct their business, or may have a material adverse effect on their financial condition and results of operations. Recent U.S. tax legislation may materially adversely affect Entergys financial condition, results of operations, and cash flows. The Tax Cuts and Jobs Act of 2017 and CARES Act of 2020 significantly changed the U.S. Internal Revenue Code, including taxation of U.S. corporations, by, among other things, reducing the federal corporate income tax rate, limiting interest deductions, and altering the expensing of capital expenditures. The Inflation Reduction Act of 2022 further significantly changed the U.S. Internal Revenue Code by, among other things, enacting a new corporate alternative minimum tax and expanding federal tax credits for clean energy production. The interpretive guidance issued by the IRS and state tax authorities may be inconsistent with Entergys own interpretation and the legislation could be subject to amendments, which could lessen or increase certain impacts of the legislation. Further, changes in tax legislation or guidance, or uncertainties regarding interpretation of such tax legislation or guidance, could impact interpretation of and negotiations around certain contractual arrangements with counterparties, which could result in unfavorable changes to such arrangements or delays. In addition, the retail regulatory treatment of the expanded tax credits and corporate alternative minimum tax included in the Inflation Reduction Act of 2022 could materially impact Entergys future cash flows, and this legislation could result in unintended consequences not yet identified that could have a material adverse impact on Entergys financial results and future cash flows. Based on initial IRS guidance and current internal forecasts, Entergy and the Registrant Subsidiaries may become subject to the corporate alternative minimum tax included in the Inflation Reduction Act of 2022 beginning in the next two to three years. The tax rate decrease included in the Tax Cuts and Jobs Act required Entergy to record a regulatory liability for income taxes payable to customers. Such regulatory liability for income taxes is described in Note 3 to the Part I Item 1A and 1B Entergy Corporation, Utility operating companies, and System Energy financial statements. Depending on the outcome of IRS examinations or tax positions and elections that Entergy may make, Entergy and the Registrant Subsidiaries may be required to record additional charges or credits to income tax expense. See Note 3 to the financial statements for discussion of the effects of the Tax Cuts and Jobs Act on 2022, 2021, and 2020 results of operations and financial condition, the provisions of the Tax Cuts and Jobs Act, and the uncertainties associated with accounting for the Tax Cuts and Jobs Act, and Note 2 to the financial statements for discussion of the regulatory proceedings that have considered the effects of the Tax Cuts and Jobs Act. For further discussion of the effects of the Inflation Reduction Act of 2022, see the Income Tax Legislation section of Entergy Corporation and Subsidiaries Managements Financial Discussion and Analysis and Note 3 to the financial statements. Changes in taxation as well as the inherent difficulty in quantifying potential tax effects of business decisions could negatively impact Entergys and the Registrant Subsidiaries results of operations, financial condition, and liquidity. Entergy and its subsidiaries make judgments regarding the potential tax effects of various transactions and results of operations to estimate their obligations to taxing authorities. These tax obligations include income, franchise, real estate, sales and use, and employment-related taxes. These judgments include provisions for potential adverse outcomes regarding tax positions that have been taken. Entergy and its subsidiaries also estimate their ability to utilize tax benefits, including those in the form of carryforwards for which the benefits have already been reflected in the financial statements. Changes in federal, state, or local tax laws or interpretive guidance relating thereto, adverse tax audit results or adverse tax rulings on positions taken by Entergy and its subsidiaries could negatively affect Entergys and the Registrant Subsidiaries results of operations, financial condition, and liquidity. The intended and unintended consequences of recently enacted legislation could have a material adverse impact on Entergys financial results and future cash flows. For further information regarding Entergys income taxes, see Note 3 to the financial statements. Entergy and its subsidiaries ability to successfully execute on their business strategies, including their ability to complete strategic transactions, is subject to significant risks, and, as a result, they may be unable to achieve some or all of the anticipated results of such strategies, which could materially affect their future prospects, results of operations, and benefits that they anticipate from such transactions. Entergy and its subsidiaries future prospects and results of operations significantly depend on their ability to successfully implement their business strategies, including achieving Entergys climate goals and commitments, which are subject to business, regulatory, economic, and other risks and uncertainties, many of which are beyond their control. As a result, Entergy and its subsidiaries may be unable to fully achieve the anticipated results of such strategies. Additionally, Entergy and its subsidiaries have pursued and may continue to pursue strategic transactions including merger, acquisition, divestiture, joint venture, restructuring, or other strategic transactions. For example, a significant portion of Entergys utility business plan over the next several years includes the construction and/or purchase of a variety of solar facilities. These or other transactions and plans are or may become subject to regulatory approval and other material conditions or contingencies, including increased costs or delays resulting from supply chain issues. The failure to complete these transactions or plans or any future strategic transaction successfully or on a timely basis could have an adverse effect on Entergys or its subsidiaries financial condition or results of operations and the markets perception of Entergys ability to execute its strategy. Further, these transactions, and any completed or future strategic transactions, involve substantial risks, including the following: acquired businesses or assets may not produce revenues, earnings, or cash flow at anticipated levels; acquired businesses or assets could have environmental, permitting, or other problems for which contractual protections prove inadequate; Part I Item 1A and 1B Entergy Corporation, Utility operating companies, and System Energy Entergy and/or its subsidiaries may assume liabilities that were not disclosed to them, that exceed their estimates, or for which their rights to indemnification from the seller are limited; Entergy may experience issues integrating businesses into its internal controls over financial reporting; the disposition of a business could divert managements attention from other business concerns; Entergy and/or its subsidiaries may be unable to obtain the necessary regulatory or governmental approvals to close a transaction, such approvals may be granted subject to terms that are unacceptable, or Entergy or its subsidiaries otherwise may be unable to achieve anticipated regulatory treatment of any such transaction or acquired business or assets; and Entergy or its subsidiaries otherwise may be unable to achieve the full strategic and financial benefits that they anticipate from the transaction, or such benefits may be delayed or may not occur at all. Entergy and its subsidiaries may not be successful in managing these or any other significant risks that they may encounter in acquiring or divesting a business, or engaging in other strategic transactions, which could have a material effect on their business, financial condition, or results of operations. The completion of capital projects, including the construction of power generation facilities, and other capital improvements, involve substantial risks. Should such efforts be unsuccessful, the financial condition, results of operations, or liquidity of Entergy and the Utility operating companies could be materially affected. Entergys and the Utility operating companies ability to complete capital projects, including the construction of power generation facilities, or make other capital improvements, such as transmission and distribution infrastructure replacements or upgrades, in a timely manner and within budget is contingent upon many variables and subject to substantial risks. These variables include, but are not limited to, project management expertise, escalating costs for materials, labor, and environmental compliance, reliance on suppliers for timely and satisfactory performance, continued pandemic-related delays and cost increases, and supply chains and material constraints, including those that may result from major storm events, both within and outside of Entergys service area. Delays in obtaining permits, challenges in securing sufficient land for the siting of solar panels, shortages in materials and qualified labor, levels of public support or opposition, suppliers and contractors not performing as expected or required under their contracts and/or experiencing financial problems that inhibit their ability to fulfill their obligations under contracts, changes in the scope and timing of projects, poor quality initial cost estimates from contractors, the inability to raise capital on favorable terms, changes in commodity prices affecting revenue, fuel costs, or materials costs, downward changes in the economy, changes in law or regulation, including environmental compliance requirements, further direct and indirect trade and tariff issues, including those associated with imported solar panels, supply chain delays or disruptions, and other events beyond the control of the Utility operating companies may occur that may materially affect the schedule, cost, and performance of these projects. If these projects or other capital improvements are significantly delayed or become subject to cost overruns or cancellation, Entergy and the Utility operating companies could incur additional costs and termination payments or face increased risk of potential write-off of the investment in the project. In addition, the Utility operating companies could be exposed to higher costs and market volatility, which could affect cash flow and cost recovery, should their respective regulators decline to approve the construction of the project or new generation needed to meet the reliability needs of customers at the lowest reasonable cost. For further information regarding capital expenditure plans and other uses of capital in connection with capital projects, including the potential construction and/or purchase of additional generation supply sources within the Utility operating companies service areas, see the Capital Expenditure Plans and Other Uses of Capital section of Managements Financial Discussion and Analysis for Entergy and each of the Registrant Subsidiaries. Failure to attract, retain and manage an appropriately qualified workforce could negatively affect Entergy or its subsidiaries results of operations. Entergy relies on a large and changing workforce of team members, including employees, contractors, and temporary staffing. Certain factors, such as an aging workforce, mismatching of skill sets, failing to appropriately Part I Item 1A and 1B Entergy Corporation, Utility operating companies, and System Energy anticipate future workforce needs, workforce impacts from public health concerns such as the COVID-19 pandemic and responsive measures, challenges competing with other employers offering fully remote work options, rising salary and other labor costs, or the unavailability of contract resources, may lead to operating challenges and increased costs. The challenges include inability to attract or retain talent, lack of resources, loss of knowledge base, and the time required for skill development. In this case, costs, including costs for contractors to replace employees, productivity costs, and safety costs, may increase. Failure to hire and adequately train replacement employees, or the future availability and cost of contract labor, may adversely affect the ability to manage and operate the business, especially considering the workforce needs associated with nuclear generation facilities and new skills required to develop and operate a modernized, technology-enabled, and lower carbon power grid. If Entergy and its subsidiaries are unable to successfully attract, retain, and manage an appropriately qualified workforce, their results of operations, financial position, and cash flows could be negatively affected. Entergy and Entergys subsidiaries, including the Utility operating companies and System Energy, may incur substantial costs to fulfill their obligations related to environmental and other matters. The businesses in which Entergys subsidiaries, including the Utility operating companies and System Energy, operate are subject to extensive environmental regulation by local, state, and federal authorities. These laws and regulations affect the manner in which the Utility operating companies and System Energy conduct their operations and make capital expenditures. These laws and regulations also affect how Entergys subsidiaries, including the Utility operating companies and System Energy, manage air emissions, discharges to water, wetlands impacts, solid and hazardous waste storage and disposal, cooling and service water intake, the protection of threatened and endangered species, certain migratory birds and eagles, hazardous materials transportation, and similar matters. Federal, state, and local authorities continually revise these laws and regulations, and the laws and regulations are subject to judicial interpretation and to the permitting and enforcement discretion vested in the implementing agencies. Developing and implementing plans for facility compliance with these requirements can lead to capital, personnel, and operation and maintenance expenditures. Violations of these requirements can subject the Utility operating companies and System Energy to enforcement actions, capital expenditures to bring existing facilities into compliance, additional operating costs or operating restrictions to achieve compliance, remediation and clean-up costs, civil penalties, and exposure to third parties claims for alleged health or property damages or for violations of applicable permits or standards. In addition, Entergy and its subsidiaries, including the Utility operating companies and System Energy, are subject to potential liability under these laws for the costs of remediation of environmental contamination of property now or formerly owned or operated by the Utility operating companies and System Energy and of property potentially contaminated by hazardous substances they generate. The Utility operating companies currently are involved in proceedings relating to sites where hazardous substances have been released and may be subject to additional proceedings in the future. Entergys subsidiaries, including the Utility operating companies and System Energy, have incurred and expect to incur significant costs related to environmental compliance. Emissions of nitrogen and sulfur oxides, mercury, particulates, greenhouse gases, and other regulated emissions from generating plants potentially are subject to increased regulation, controls, and mitigation expenses. In addition, existing environmental regulations and programs promulgated by the EPA often are challenged legally, or are revised or withdrawn by the EPA, sometimes resulting in large-scale changes to anticipated regulatory regimes and the resulting need to shift course, both operationally and economically, depending on the nature of the changes. Risks relating to global climate change, initiatives to regulate, or otherwise compel reductions of greenhouse gas emissions, and water availability issues are discussed below. Entergy and its subsidiaries may not be able to obtain or maintain all required environmental regulatory approvals. If there is a delay in obtaining any required environmental regulatory approvals, or if Entergy and its subsidiaries fail to obtain, maintain, or comply with any such approval, the operation of its facilities could be stopped or become subject to additional costs. For further information regarding environmental regulation and environmental matters, including Entergys response to climate change, see the Regulation of Entergy s Business Environmental Regulation section of Part I, Item 1. Part I Item 1A and 1B Entergy Corporation, Utility operating companies, and System Energy The Utility operating companies, System Energy, and Entergys non-regulated operations may incur substantial costs related to reliability standards. Entergys business is subject to extensive and mandatory reliability standards. Such standards, which are established by the NERC, the SERC, and other regional enforcement entities, are approved by the FERC and frequently are reviewed, amended, and supplemented. Failure to comply with such standards could result in the imposition of fines or civil penalties, and potential exposure to third party claims for alleged violations of such standards. The standards, as well as the laws and regulations that govern them, are subject to judicial interpretation and to the enforcement discretion vested in the implementing agencies. In addition to exposure to civil penalties and fines, the Utility operating companies have incurred and expect to incur significant costs related to compliance with new and existing reliability standards, including costs associated with the Utility operating companies transmission system and generation assets. In addition, the retail regulators of the Utility operating companies possess the jurisdiction, and in some cases have exercised such jurisdiction, to impose standards governing the reliable operation of the Utility operating companies distribution systems, including penalties if these standards are not met. The changes to the reliability standards applicable to the electric power industry are ongoing, and Entergy cannot predict the ultimate effect that the reliability standards will have on its Utility and Entergys non-regulated operations. Environmental and regulatory obligations intended to combat the effects of climate change, including by compelling greenhouse gas emission reductions or reporting, increasing clean or renewable energy requirements, or placing a price on greenhouse gas emissions, or the achievement of voluntary climate commitments could materially affect the financial condition, results of operations, and liquidity of Entergy and Entergys subsidiaries, including the Utility operating companies and System Energy. In an effort to address climate change concerns, some federal, state, and local authorities are calling for additional laws and regulations aimed at known or suspected causes of climate change. For example, the EPA, various environmental interest groups, and other organizations have focused considerable attention on CO_2 emissions from power generation facilities and their potential role in climate change. The EPA has promulgated regulations controlling greenhouse gas emissions from certain vehicles, and from new, existing, and significantly modified stationary sources of emissions, including electric generating units. Such regulations continue to evolve. As examples of state action, in the Northeast, the Regional Greenhouse Gas Initiative establishes a cap on CO_2 emissions from electric power plants and requires generators to purchase emission permits to cover their CO_2 emissions, and a similar program has been developed in California. In Louisiana, the Office of the Governor announced the creation of a Climate Initiatives Task Force and issued an executive order that established a path to net-zero emissions by 2050 while the City Council of New Orleans passed a renewable and clean portfolio standard that sets a goal of net-zero emissions by 2040 and absolute zero emissions by 2050. The impact that continued changes in the governmental response to climate change risk and any judicial interpretation thereof will have on existing and pending environmental laws and regulations related to greenhouse gas emissions currently is unclear. Developing and implementing plans for compliance with greenhouse gas emissions reduction or reporting or clean/renewable energy requirements, or for achieving voluntary climate commitments can lead to additional capital, personnel, and operation and maintenance expenditures and could significantly affect the economic position of existing facilities and proposed projects. The operations of low or non-emitting generating units (such as nuclear units) at lower than expected capacity factors could require increased generation from higher emitting units, thus increasing Entergys greenhouse gas emission rate. Moreover, long-term planning to meet environmental requirements can be negatively impacted and costs may increase to the extent laws and regulations change prior to full implementation. These requirements could, in turn, lead to changes in the planning or operations of balancing authorities or organized markets in areas where Entergys subsidiaries, including the Utility operating companies or System Energy, do business. Violations of such requirements may subject the Utility operating companies to enforcement actions, capital expenditures to bring existing facilities into compliance, additional operating costs or operating restrictions to achieve compliance, civil penalties, and exposure to third parties claims for alleged health Part I Item 1A and 1B Entergy Corporation, Utility operating companies, and System Energy or property damages or for violations of applicable permits or standards. Further, real or perceived violations of environmental regulations, including those related to climate change, or inability to meet Entergys voluntary climate commitments, could adversely impact Entergys reputation or inhibit Entergys ability to pursue its decarbonization objectives. To the extent Entergy believes any of these costs are recoverable in rates, however, additional material rate increases for customers could be resisted by Entergys regulators and, in extreme cases, Entergys regulators might attempt to deny or defer timely recovery of these costs. Future changes in regulation or policies governing the reporting or emission of CO 2 and other greenhouse gases or mix of generation sources could (i) result in significant additional costs to Entergys Utility operating companies, their suppliers, or customers, (ii) make some of Entergys electric generating units uneconomical to maintain or operate, (iii) result in the early retirement of generation facilities and stranded costs if Entergys Utility operating companies are unable to fully recover the costs and investment in generation, and (iv) increase the difficulty that Entergy and its Utility operating companies have with obtaining or maintaining required environmental regulatory approvals, each of which could materially affect the financial condition, results of operations, and liquidity of Entergy and its subsidiaries. In addition, lawsuits have occurred or are reasonably expected against emitters of greenhouse gases alleging that these companies are liable for personal injuries and property damage caused by climate change. These lawsuits may seek injunctive relief, monetary compensation, and punitive damages. In March 2019, Entergy voluntarily set a climate goal to achieve a 50 percent reduction in its carbon emission rate from the year 2000 by 2030. In September 2020, Entergy voluntarily committed to achieving net zero carbon emissions by 2050. In November 2022, Entergy voluntarily set a climate goal to achieve 50 percent carbon-free energy capacity by 2030. Risks to achieving the 2030 and 2050 goals include, among other things, the ability to execute on renewable resource plans, regulatory approvals, customer demand for carbon-free energy, potential tariffs, carbon policy and regulation, and supply chain costs and constraints. Technology research and development, innovation, and advancements in carbon-free generation are also critical to Entergys ability to achieve its 2050 commitment. Entergy cannot predict the ultimate impact of achieving these objectives, or the various implementation aspects, on its system reliability, or its results of operations, financial condition, or liquidity. The physical effects of climate change could materially affect the financial condition, results of operations, and liquidity of Entergy and its subsidiaries. Potential physical risks from climate change include an increase in sea level, wind and storm surge damages, more frequent or intense hurricanes and wildfires, wetland and barrier island erosion, flooding and changes in weather conditions (such as increases in precipitation, drought, or changes in average temperatures), and potential increased impacts of extreme weather conditions or storms. Entergys subsidiaries own assets in, and serve, communities that are at risk from sea level rise, changes in weather conditions, storms, and loss of the protection offered by coastal wetlands. A significant portion of the nations oil and gas infrastructure is located in these areas and susceptible to storm damage that could be aggravated by the physical impacts of climate change, which could give rise to fuel supply interruptions and price spikes. Entergy and its subsidiaries also face the risk that climate change could impact the availability and quality of water supplies necessary for operations. These and other physical changes could result in changes in customer demand, increased costs associated with repairing and maintaining generation facilities and transmission and distribution systems resulting in increased maintenance and capital costs (and potential increased financing needs), limits on the Entergy systems ability to meet peak customer demand, more frequent and longer lasting outages, increased regulatory oversight, criticism or adverse publicity, and lower customer satisfaction. Also, to the extent that climate change adversely impacts the economic health of a region or results in energy conservation or demand side management programs, it may adversely impact customer demand and revenues. Such physical or operational risks could have a material effect on Entergys and its subsidiaries financial condition, results of operations, and liquidity. Part I Item 1A and 1B Entergy Corporation, Utility operating companies, and System Energy Due in part to the recent increase in frequency and intensity of major storm activity along the Gulf Coast, Entergy is developing plans to accelerate investments that would enhance the resilience of the electric systems of the Utility operating companies to enable them to better withstand major storms or other adverse weather events, to enable more rapid restoration of electricity after major storm or other adverse events, and to deliver electricity to critical customers more immediately after such events. The need for this investment and these expenditures could give rise to liquidity, capital or other financing-related risks as well as result in upward pressure on the retail rates of the Utility operating companies, which, particularly when combined with upward pressure resulting from the recovery of the costs of recent and future storms, may result in adverse actions by the Utility operating companies retail regulators or effectively limit the ability to make other planned capital or other investments. Continued and future availability and quality of water for cooling, process, and sanitary uses could materially affect the financial condition, results of operations, and liquidity of Entergy and its subsidiaries. Water is a vital natural resource that is also critical to Entergy and its subsidiaries. Entergys and its subsidiaries facilities use water for cooling, boiler make-up, sanitary uses, potable supply, and many other uses. Entergys Utility operating companies also own and/or operate hydroelectric facilities. Accordingly, water availability and quality are critical to Entergys and its subsidiaries business operations. Impacts to water availability or quality could negatively impact both operations and revenues. Entergy and its subsidiaries secure water through various mechanisms (ground water wells, surface waters intakes, municipal supply, etc.) and operate under the provisions and conditions set forth by the provider and/or regulatory authorities. Entergy and its subsidiaries also obtain and operate in substantial compliance with water discharge permits issued under various provisions of the Clean Water Act and/or state water pollution control provisions. Regulations and authorizations for both water intake and use and for waste discharge can become more stringent in times of water shortages, low flows in rivers, low lake levels, low groundwater aquifer volumes, and similar conditions. The increased use of water by industry, agriculture, and the population at large, population growth, and the potential impacts of climate change on water resources may cause water use restrictions that affect Entergy and its subsidiaries. Entergy and its subsidiaries may not be adequately hedged against changes in commodity prices, which could materially affect Entergys and its subsidiaries results of operations, financial condition, and liquidity. To manage near-term and medium-term financial exposure related to commodity price fluctuations, Entergy and its subsidiaries, including the Utility operating companies, may enter into contracts to hedge portions of their purchase and sale commitments, fuel requirements, and inventories of natural gas, uranium and its conversion and enrichment, coal, refined products, and other commodities, within established risk management guidelines. As part of this strategy, Entergy and its subsidiaries may utilize fixed- and variable-price forward physical purchase and sales contracts, futures, financial swaps, and option contracts traded in the over-the-counter markets or on exchanges. However, Entergy and its subsidiaries normally cover only a portion of the exposure of their assets and positions to market price volatility, and the coverage will vary over time. In addition, Entergy also elects to leave certain volumes during certain years unhedged. To the extent Entergy and its subsidiaries have unhedged positions, fluctuating commodity prices can materially affect Entergys and its subsidiaries results of operations and financial position. Although Entergy and its subsidiaries devote a considerable effort to these risk management strategies, they cannot eliminate all the risks associated with these activities. As a result of these and other factors, Entergy and its subsidiaries cannot predict with precision the impact that risk management decisions may have on their business, results of operations, or financial position. Entergys over-the-counter financial derivatives are subject to rules implementing the Dodd-Frank Wall Street Reform and Consumer Protection Act that are designed to promote transparency, mitigate systemic risk, and protect against market abuse. Entergy cannot predict the impact any proposed or not fully-implemented final rules Part I Item 1A and 1B Entergy Corporation, Utility operating companies, and System Energy will have on its ability to hedge its commodity price risk or on over-the-counter derivatives markets as a whole, but such rules and regulations could have a material effect on Entergy's risk exposure, as well as reduce market liquidity and further increase the cost of hedging activities. Entergy has guaranteed or indemnified the performance of a portion of the obligations relating to hedging and risk management activities. Reductions in Entergys or its subsidiaries credit quality or changes in the market prices of energy commodities could increase the cash or letter of credit collateral required to be posted in connection with hedging and risk management activities, which could materially affect Entergys or its subsidiaries liquidity and financial position. The Utility operating companies and Entergys non-regulated operations are exposed to the risk that counterparties may not meet their obligations, which may materially affect the Utility operating companies and Entergys non-regulated operations. The hedging and risk management practices of the Utility operating companies and Entergy's non-regulated operations are exposed to the risk that counterparties that owe Entergy and its subsidiaries money, energy, or other commodities will not perform their obligations. Currently, some hedging agreements contain provisions that require the counterparties to provide credit support to secure all or part of their obligations to Entergy or its subsidiaries. If the counterparties to these arrangements fail to perform, Entergy or its subsidiaries may enforce and recover the proceeds from the credit support provided and acquire alternative hedging arrangements, which credit support may not always be adequate to cover the related obligations. In such event, Entergy and its subsidiaries might incur losses in addition to amounts, if any, already paid to the counterparties. In addition, the credit commitments of Entergys lenders under its bank facilities may not be honored for a variety of reasons, including unexpected periods of financial distress affecting such lenders, which could materially affect the adequacy of its liquidity sources. Market performance and other changes may decrease the value of benefit plan assets, which then could require additional funding and result in increased benefit plan costs. The performance of the capital markets affects the values of the assets held in trust under Entergys pension and postretirement benefit plans. A decline in the market value of the assets may increase the funding requirements relating to Entergys benefit plan liabilities and also result in higher benefit costs. As the value of the assets decreases, the expected return on assets component of benefit costs decreases, resulting in higher benefits costs. Additionally, asset losses are incorporated into benefit costs over time, thus increasing benefits costs. Volatility in the capital markets has affected the market value of these assets, which may affect Entergys planned levels of contributions in the future. Additionally, changes in interest rates affect the liabilities under Entergys pension and postretirement benefit plans; as interest rates decrease, the liabilities increase, potentially requiring additional funding and recognition of higher liability carrying costs. The funding requirements of the obligations related to the pension benefit plans can also increase as a result of changes in, among other factors, retirement rates, life expectancy assumptions, or federal regulations. For further information regarding Entergys pension and other postretirement benefit plans, refer to the Critical Accounting Estimates Qualified Pension and Other Postretirement Benefits section of Managements Financial Discussion and Analysis for Entergy and each of its Registrant Subsidiaries and Note 11 to the financial statements. The litigation environment in the states in which the Registrant Subsidiaries operate poses a significant risk to those businesses. Entergy and its subsidiaries and related entities are involved in the ordinary course of business in a number of lawsuits involving employment, commercial, asbestos, hazardous material and customer matters, and injuries and damages issues, among other matters. The states in which the Registrant Subsidiaries operate have proven to be unusually litigious environments. Judges and juries in these states have demonstrated a willingness to grant large verdicts, including punitive damages, to plaintiffs in personal injury, property damage, and business tort Part I Item 1A and 1B Entergy Corporation, Utility operating companies, and System Energy cases. Entergy and its subsidiaries use legal and appropriate means to contest litigation threatened or filed against them, but the litigation environment in these states poses a significant business risk. Terrorist attacks, physical attacks, cyber attacks, system failures or data breaches of Entergys and its subsidiaries or their suppliers infrastructure or technology systems may adversely affect Entergys results of operations. Entergy and its subsidiaries operate in a business that requires evolving information technology systems that include sophisticated data collection, processing systems, software, network infrastructure, and other technologies that are becoming more complex and may be subject to mandatory and prescriptive reliability and security standards. The functionality of Entergys technology systems depends on its own and its suppliers and their contractors technology. Suppliers and their contractors technology systems to which Entergy is connected directly or indirectly support a variety of business processes and activities to store sensitive data, including (i) intellectual property, (ii) proprietary business information, (iii) personally identifiable information of customers, employees, and others, and (iv) data with respect to invoicing and the collection of payments, accounting, procurement, and supply-chain activities. Any significant failure or malfunction of such information technology systems could result in loss of or inappropriate access to data or disruptions of operations. There have been attacks and threats of attacks on energy infrastructure by cyber actors, including those associated with foreign governments. As an operator of critical infrastructure, Entergy and its subsidiaries face a heightened risk of physical attacks or acts or threats of terrorism, cyber attacks, including ransomware attacks, and data breaches, whether as a direct or indirect act against one of Entergys generation, transmission or distribution facilities, operations centers, infrastructure, or information technology systems used to manage, monitor, and transport power to customers and perform day-to-day business functions as well as against the systems of critical suppliers and contractors. Further, attacks may become more frequent in the future as technology becomes more prevalent in energy infrastructure. An attack could affect Entergys ability to operate, including its ability to operate the information technology systems and network infrastructure on which it relies to conduct business. Given the rapid technological advancements of existing and emerging threats, Entergys technology systems remain inherently vulnerable despite implementations and enhancements of the multiple layers of security and controls. If Entergys or its subsidiaries technology systems, or those of critical suppliers or contractors, were compromised and unable to detect or recover in a timely fashion to a normal state of operations, Entergy or its subsidiaries could be unable to perform critical business functions that are essential to the companys well-being and could result in a loss of or inappropriate access to its confidential, sensitive, and proprietary information, including personal information of its customers, employees, suppliers, and others in Entergys care. Any such attacks, failures, or data breaches could have a material effect on Entergys and the Utility operating companies business, financial condition, results of operations or reputation. Although Entergy and the Utility operating companies purchase insurance for cyber attacks and data breaches, such insurance prices have increased substantially, and coverage may not be adequate to cover all losses that might arise in connection with these events. Such events may also expose Entergy to an increased risk of litigation (and associated damages and fines). Entergy and the Registrant Subsidiaries are subject to risks associated with their ability to obtain adequate insurance at acceptable costs. The global economic cost to insurers resulting from cyber attacks, natural disasters and other catastrophic events, in addition to an increased focus on climate issues could have disruptive effects on insurance markets. The availability of insurance capacity may decrease, and the insurance policies that Entergy or the Registrant Subsidiaries are able to obtain may have higher deductibles, higher premiums, and more restrictive terms and conditions. Further, the insurance policies of Entergy or the Registrant Subsidiaries may not cover all of their potential exposures or actual amounts of losses incurred. Part I Item 1A and 1B Entergy Corporation, Utility operating companies, and System Energy Significant increases in commodity prices, other materials and supplies, and operation and maintenance expenses may adversely affect Entergy's results of operations, financial condition, and liquidity. Entergy and its subsidiaries have observed and expect future inflationary pressures related to commodity prices, other materials and supplies, and operation and maintenance expenses, including in the areas of labor, health care, and pension costs. The contracts for the construction of certain o f the Utility operating companies generation facilities also have included, and in the future may include, price adjustment provisions that, subject to certain limitations, may enable the contractor to increase the contract price to reflect increases in certain costs of constructing the facility. These inflationary pressures could impact the ability of Entergy and its subsidiaries to control costs and/or make substantial investments in their businesses, including their ability to recover costs and investments, and to earn their allowed return on equity within frameworks established by their regulators while maintaining affordability of their services for their customers, in addition to having unpredictable effects on Entergys customers. Increases in commodity prices, other materials and supplies, and operation and maintenance expenses, including increasing labor costs and costs and funding requirements associated with Entergy's defined benefit retirement plans, health care plans, and other employee benefits, could increase their financing needs and otherwise adversely affect their results of operations, financial condition, and liquidity. (Entergy New Orleans) The effect of higher purchased gas cost charges to customers taking gas service may adversely affect Entergy New Orleanss results of operations and liquidity.

Gas rates charged to retail gas customers are comprised primarily of purchased gas cost charges, which provide no return or profit to Entergy New Orleans, and distribution charges, which provide a return or profit to the utility. Distribution charges recover fixed costs on a volumetric basis and, thus, are affected by the amount of gas sold to customers. When purchased gas cost charges increase due to higher gas procurement costs, customer usage may decrease, especially in weaker economic times, resulting in lower distribution charges for Entergy New Orleans, which, given its relatively smaller size, could adversely affect results of operations. Purchased gas cost charges, which comprise most of a customers bill and may be adjusted monthly, represent gas commodity costs that Entergy New Orleans recovers from its customers. Entergy New Orleanss cash flows can be affected by differences between the time when gas is purchased and the time when ultimate recovery from customers occurs. (Entergy Corporation and System Energy) System Energy owns and, through an affiliate, operates a single nuclear generating facility, and it is dependent on sales to affiliated companies for all of its revenues. Certain contractual arrangements relating to System Energy, the affiliated companies, and these revenues are the subject of ongoing litigation and regulatory proceedings. The aggregate amount of refunds claimed in these proceedings substantially exceeds the current net book value of System Energy. In the event of an adverse decision in one or more of these proceedings requiring the payment of substantial additional refunds, System Energy would be required to seek financing to pay such refunds which financing may not be available on terms acceptable to System Energy, or may not be available at all, when required. If one or more of the foregoing events occurs, System Energy may be required to explore other options or protections available to it to extend, restructure, or retire its indebtedness and to prioritize its obligations. System Energys operating revenues are derived from the allocation of the capacity, energy, and related costs associated with its 90% ownership/leasehold interest in Grand Gulf. Charges under the Unit Power Sales Agreement are paid by the Utility operating companies (other than Entergy Texas) as consideration for their respective entitlements to receive capacity and energy. The useful economic life of Grand Gulf is finite and is limited by the terms of its operating license, which currently expires in November 2044. System Energys financial condition depends both on the receipt of payments from the Utility operating companies (other than Entergy Texas) Part I Item 1A and 1B Entergy Corporation, Utility operating companies, and System Energy under the Unit Power Sales Agreement and on the continued commercial operation of Grand Gulf. The Unit Power Sales Agreement is currently the subject of several litigation proceedings at the FERC, including a challenge with respect to System Energys uncertain tax positions, sale leaseback arrangement, authorized return on equity and capital structure, a broader investigation of rates under the Unit Power Sales Agreement, and a prudence complaint challenging the extended power uprate completed at Grand Gulf in 2012 and the operation and management of Grand Gulf, particularly in the 2016-2020 time period. The claims in these proceedings include claims for refunds and claims for rate adjustments. The aggregate amount of refunds claimed in these proceedings substantially exceeds the current net book value of System Energy. Entergy Corporation is not obligated to provide funding to System Energy to enable it to pay any such refunds. In the event that an adverse decision in one or more of these proceedings required the payment of substantial additional refunds, System Energy would need to source additional financing to pay such refunds. Such financing may not be available on terms acceptable to System Energy, or may not be available at all, when required. An adverse development in one or more of these proceedings also could jeopardize System Energys ability to finance its operations and pay its obligations, at a reasonable cost or when due. If one or more of the foregoing events occurs, System Energy may be required to explore other options or protections available to it to extend, restructure, or retire its indebtedness and to prioritize its obligations. One or more rating agencies may downgrade the ratings of System Energy or its debt securities, which could adversely affect the market prices of System Energys debt securities and otherwise adversely affect System Energys financial condition. In addition, an order requiring System Entergy to pay substantial additional refunds could result in a default and, in certain cases, acceleration under one or more of System Energys existing bond indentures, credit agreements, or other financing arrangements. Certain events constituting events of default under System Energys financing agreements may also result in defaults under, or acceleration with respect to, financing arrangements involving certain credit agreement and guarantee obligations of Entergy Corporation. These proceedings are pending before their respective adjudicators and no final decisions have been reached. Thus, Entergy cannot predict with certainty the outcome of any of these proceedings, or the magnitude of any refunds or rate adjustments, and an adverse outcome in any of them could have a material adverse effect on Entergys or System Energys results of operations, financial condition, or liquidity. In particular, in connection with the uncertain tax position proceeding and related December 2022 FERC order and System Energys compliance report filed in January 2023, if the FERC were to order additional refunds at a level consistent with the position of the LPSC, the APSC, and the City Council on the remedy for the formerly uncertain tax positions, System Energys continued financial viability would be jeopardized. See Note 2 to the financial statements for further discussion of the proceedings. The Utility operating companies (other than Entergy Texas) have agreed to implement certain protocols for providing retail regulators with information regarding rates billed under the Unit Power Sales Agreement. For information regarding the Unit Power Sales Agreement, the sale and leaseback transactions and certain other agreements relating to certain Entergy System companies support of System Energy, see Notes 5 and 8 to the financial statements and the Utility - System Energy and Related Agreements section of Part I, Item 1. (Entergy Corporation) Entergys non-regulated operations are subject to substantial governmental regulation and may be adversely affected by legislative, regulatory, or market design changes, as well as liability under, or any future inability to comply with, existing or future regulations or requirements. Entergys non-regulated operations are subject to regulation under federal, state, and local laws. Compliance with the requirements under these various regulatory regimes may cause Entergys non-regulated operations to incur significant additional costs, and failure to comply with such requirements could result in the shutdown of the non-complying facility, the imposition of liens, fines, and/or civil or criminal liability. Part I Item 1A and 1B Entergy Corporation, Utility operating companies, and System Energy Public utilities under the Federal Power Act are required to obtain FERC acceptance of their rate schedules for wholesale sales of electricity. Entergys non-regulated operations include legal entities that meet the definition of a public utility under the Federal Power Act by virtue of making wholesale sales of electric energy and/or owning wholesale electric transmission facilities. The FERC has granted those entities the authority to sell electricity at market-based rates. The FERCs orders that grant those entities market-based rate authority reserve the right to revoke or revise that authority if the FERC subsequently determines that those entities can exercise market power in transmission or generation, create barriers to entry, or engage in abusive affiliate transactions. In addition, market-based sales are subject to certain market behavior rules, and if one of those entities were deemed to have violated one of those rules, they would be subject to potential disgorgement of profits associated with the violation and/or suspension or revocation of their market-based rate authority and potential penalties of up to $1.29 million per day per violation. If one of those entities were to lose their market-based rate authority, it would be required to obtain the FERCs acceptance of a cost-of-service rate schedule and could become subject to the accounting, record-keeping, and reporting requirements that are imposed on utilities with cost-based rate schedules. This could have an adverse effect on the rates those entities charge for power from its facilities. Entergys non-regulated operations are also affected by legislative and regulatory changes, as well as by changes to market design, market rules, tariffs, cost allocations, and bidding rules imposed by the existing Independent System Operator. The Independent System Operator that oversees the relevant wholesale power market may impose, and in the future may continue to impose, mitigation, including price limitations, offer caps and other mechanisms, to address some of the volatility and the potential exercise of market power in that market. These types of price limitations and other regulatory mechanisms may have an adverse effect on the profitability of Entergys non-regulated operations generation facilities that sell energy and capacity into the wholesale power markets. The regulatory environment applicable to the electric power industry is subject to changes as a result of restructuring initiatives at both the state and federal levels. Entergy cannot predict the future design of the wholesale power markets or the ultimate effect that the changing regulatory environment will have on Entergys non-regulated operations. In addition, in some of these markets, interested parties have proposed material market design changes, including the elimination of a single clearing price mechanism, have raised claims that the competitive marketplace is not working, and have made proposals to re-regulate the markets, impose a generation tax, or require divestitures by generating companies to reduce their market share. Other proposals to re-regulate may be made and legislative or other attention to the electric power market restructuring process may delay or reverse the deregulation process, which could require material changes to business planning models. If competitive restructuring of the electric power markets is reversed, modified, discontinued, or delayed, Entergys non-regulated operations results of operations, financial condition, and liquidity could be materially affected. As a holding company, Entergy Corporation depends on cash distributions from its subsidiaries to meet its debt service and other financial obligations and to pay dividends on its common stock, and has provided, and may continue to provide, capital contributions or debt financing to its subsidiaries, which would reduce the funds available to meet its other financial obligations. Entergy Corporation is a holding company with no material revenue generating operations of its own or material assets other than the stock of its subsidiaries. Accordingly, all of its operations are conducted by its subsidiaries. Entergy Corporation has provided, and may continue to provide, capital contributions or debt financing to its subsidiaries, which would reduce the funds available to meet its financial obligations, including making interest and principal payments on outstanding indebtedness, and to pay dividends on Entergys common stock. Entergy Corporations ability to satisfy its financial obligations, including the payment of interest and principal on its outstanding debt, and to pay dividends on its common stock depends on the payment to it of dividends or distributions by its subsidiaries. The subsidiaries of Entergy Corporation are separate and distinct legal entities and have no obligation, contingent or otherwise, to pay any dividends or make distributions to Entergy Corporation. The ability of such subsidiaries to make payments of dividends or distributions to Entergy Part I Item 1A and 1B Entergy Corporation, Utility operating companies, and System Energy Corporation depends on their results of operations and cash flows and other items affecting retained earnings, and on any applicable legal, regulatory, or contractual limitations on subsidiaries ability to pay such dividends or distributions. Prior to providing funds to Entergy Corporation, such subsidiaries have financial and regulatory obligations that must be satisfied, including among others, debt service and, in the case of Entergy Utility Holding Company and Entergy Texas, dividends and distributions on preferred securities. Any distributions from the Registrant Subsidiaries other than Entergy Texas and System Energy are paid directly to Entergy Utility Holding Company and are therefore subject to prior payment of distributions on its preferred securities.

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Item 1. Business Please refer to the Glossary of Terms for definitions of defined terms and abbreviations used in this combined Annual Report on Form 10-K. Eversource Energy, headquartered in Boston, Massachusetts and Hartford, Connecticut, is a public utility holding company subject to regulation by the Federal Energy Regulatory Commission (FERC) under the Public Utility Holding Company Act of 2005. We are engaged primarily in the energy delivery business through the following wholly-owned utility subsidiaries: The Connecticut Light and Power Company (CLP), a regulated electric utility that serves residential, commercial and industrial customers in parts of Connecticut; NSTAR Electric Company (NSTAR Electric), a regulated electric utility that serves residential, commercial and industrial customers in parts of eastern and western Massachusetts and owns solar power facilities, and its wholly-owned subsidiary Harbor Electric Energy Company (HEEC), also a regulated electric utility that distributes electric energy to its sole customer; Public Service Company of New Hampshire (PSNH), a regulated electric utility that serves residential, commercial and industrial customers in parts of New Hampshire; NSTAR Gas Company (NSTAR Gas), a regulated natural gas utility that serves residential, commercial and industrial customers in parts of Massachusetts; Eversource Gas Company of Massachusetts (EGMA), a regulated natural gas utility that serves residential, commercial and industrial customers in parts of Massachusetts; Yankee Gas Services Company (Yankee Gas), a regulated natural gas utility that serves residential, commercial and industrial customers in parts of Connecticut; and Aquarion Company (Aquarion), a utility holding company that owns five separate regulated water utility subsidiaries and collectively serves residential, commercial, industrial, and municipal and fire protection customers in parts of Connecticut, Massachusetts and New Hampshire. CLP, NSTAR Electric and PSNH also serve New England customers through Eversource Energy's electric transmission business. Along with NSTAR Gas, EGMA and Yankee Gas, each is doing business as Eversource Energy in its respective service territory. Eversource Energy, CLP, NSTAR Electric and PSNH each report their financial results separately. We also include information in this report on a segment basis for Eversource Energy. Eversource Energy has four reportable segments: electric distribution, electric transmission, natural gas distribution and water distribution. These segments represent substantially all of Eversource Energy's total consolidated revenues. CLP, NSTAR Electric and PSNH do not report separate business segments. Eversource Energy also has an offshore wind business, which includes a 50 percent ownership interest in offshore wind projects that are being developed and constructed through a joint and equal partnership with rsted. ELECTRIC DISTRIBUTION SEGMENT Eversource Energy's electric distribution segment consists of the distribution businesses of CLP, NSTAR Electric and PSNH, which are engaged in the distribution of electricity to retail customers in Connecticut, Massachusetts and New Hampshire, respectively, and the solar power facilities of NSTAR Electric. ELECTRIC DISTRIBUTION CONNECTICUT THE CONNECTICUT LIGHT AND POWER COMPANY CLP's distribution business consists primarily of the purchase, delivery and sale of electricity to its residential, commercial and industrial customers. As of December 31, 2022, CLP furnished retail franchise electric service to approximately 1.28 million customers in 149 cities and towns in Connecticut, covering an area of approximately 4,400 square miles. CLP does not own any electric generation facilities. Rates CLP is subject to regulation by the Connecticut Public Utilities Regulatory Authority (PURA), which, among other things, has jurisdiction over rates, certain dispositions of property and plant, mergers and consolidations, issuances of long-term securities, standards of service and construction and operation of facilities. CLP's present general rate structure consists of various rate and service classifications covering residential, commercial and industrial services. CLP's retail rates include a delivery service component, which includes distribution, transmission, conservation, renewable energy programs and other charges that are assessed on all customers. Under Connecticut law, all of CLP's customers are entitled to choose their energy suppliers, while CLP remains their electric distribution company. For those customers who do not choose a competitive energy supplier, CLP purchases power on behalf of, and passes the related cost without mark-up through to, those customers under standard service (SS) rates for customers with less than 500 kilowatts of demand (residential customers and small and medium commercial and industrial customers), and supplier of last resort service (LRS) rates for customers with 500 kilowatts or more of demand (larger commercial and industrial customers). CLP charges customers only the amount that it pays generators for producing electricity and does not earn a profit on the cost of electricity. The rates established by PURA for CLP are comprised of the following: An electric generation service charge, which recovers energy-related costs incurred as a result of providing electric generation service supply to all customers who have not migrated to competitive energy suppliers. The generation service charge is adjusted periodically and reconciled annually in accordance with the policies and procedures of the PURA, with any differences refunded to, or recovered from, customers. A distribution charge, which includes a fixed customer charge and a demand and/or energy charge to collect the costs of building and expanding the infrastructure to deliver electricity to customers, as well as ongoing operating costs to maintain the infrastructure. A revenue decoupling adjustment that reconciles annual base distribution rate recovery amounts recovered from customers to the pre-established level of baseline distribution delivery service revenue requirement approved by PURA. An Electric System Improvements (ESI) charge, which collects the costs of building and expanding the infrastructure to deliver electricity to customers above the level recovered through the distribution charge. The ESI also recovers costs associated with CLPs system resiliency program. The ESI is adjusted periodically and reconciled annually in accordance with the policies and procedures of the PURA, with any differences refunded to, or recovered from, customers. A Federally Mandated Congestion Charge (FMCC), which recovers any costs imposed by the FERC as part of the New England Standard Market Design, including locational marginal pricing, locational installed capacity payments, any costs approved by PURA to reduce these charges, as well as other costs approved by PURA. The FMCC has both a bypassable component and a non-bypassable component, and is adjusted periodically and reconciled annually in accordance with the policies and procedures of the PURA, with any differences refunded to, or recovered from, customers. A transmission charge that recovers the cost of transporting electricity over high-voltage lines from generating plants to substations, including costs allocated by ISO-NE to maintain the wholesale electric market. The transmission charge is adjusted periodically and reconciled annually to actual costs incurred, and reviewed by PURA, with any difference refunded to, or recovered from, customers. A Competitive Transition Assessment (CTA) charge, assessed to recover stranded costs associated with electric industry restructuring such as various IPP contracts. The CTA is reconciled annually to actual costs incurred and reviewed by PURA, with any difference refunded to, or recovered from, customers. A Systems Benefits Charge (SBC), established to fund expenses associated with various hardship and low-income programs. The SBC is reconciled annually to actual costs incurred, and reviewed by PURA, with any difference refunded to, or recovered from, customers. A Renewable Energy Investment Charge, which is used to promote investment in renewable energy sources. Amounts collected by this charge are deposited into the Connecticut Clean Energy Fund and administered by the Connecticut Green Bank. A Conservation Adjustment Mechanism (CAM) charge established to implement cost-effective energy conservation programs and market transformation initiatives. The CAM charge is reconciled annually to actual costs incurred, and reviewed by PURA, with any difference refunded to, or recovered from, customers through an approved adjustment to the following years energy conservation spending plan budget. As required by regulation, CLP has entered into long-term contracts for the purchase of (i) products from renewable energy facilities, which may include energy, renewable energy certificates, or capacity, (ii) capacity-related contracts with generation facilities, and (iii) contracts for peaking capacity. Some of these contracts are subject to sharing agreements with UI, whereby CLP is responsible for 80 percent and UI for 20 percent of the net costs or benefits. CLP's portion of the costs and benefits of these contracts will be paid by, or refunded to, CLP's customers. Distribution Rate Case : CLP's distribution rates were established in an April 2018 PURA-approved rate case settlement agreement with rates effective May 1, 2018, and incremental step adjustments effective May 1, 2019 and May 1, 2020. CLP Settlement Agreement : On October 1, 2021, CLP entered into a settlement agreement with the DEEP, Office of Consumer Counsel, Office of the Attorney General and the Connecticut Industrial Energy Consumers, resolving certain issues that arose in then-pending regulatory proceedings initiated by PURA. PURA approved the settlement agreement on October 27, 2021. In accordance with the settlement agreement, CLP agreed that its current base distribution rates shall be frozen, subject to certain customer credits, until no earlier than January 1, 2024. The rate freeze applies only to base distribution rates (including storm costs) and not to other rate mechanisms such as the retail rate components, rate reconciling mechanisms, formula rates and any other adjustment mechanisms. The rate freeze also does not apply to any cost recovery mechanism outside of the base distribution rates with regard to grid-modernization initiatives or any other proceedings, either currently pending or that may be initiated during the rate freeze period, that may place additional obligations on CLP. The approval of the settlement agreement satisfies the Connecticut statute of rate review requirements that requires electric utilities to file a distribution rate case within four years of the last rate case. Sources and Availability of Electric Power Supply As noted above, CLP does not own any generation assets and purchases energy supply to serve its SS and LRS loads from a variety of competitive sources through requests for proposals. During 2022, CLP supplied approximately 56 percent of its customer load at SS or LRS rates while the other 44 percent of its customer load had migrated to competitive energy suppliers. In terms of the total number of CLP customers, this equates to 14 percent being on competitive supply, while 86 percent remain with SS or LRS. Because this customer migration is only for energy supply service, it has no impact on CLP's electric distribution business or its operating income. As approved by PURA, CLP periodically enters into full requirements supply contracts for SS loads for periods of up to one year. CLP typically enters into full requirements supply contracts for LRS loads every three months. If CLP does not obtain full requirements supply contracts for 100 percent of the customer load for any period, it is authorized by PURA to meet the remaining load obligations directly through the ISO-NE wholesale markets. Currently, CLP has full requirements supply contracts in place for 80 percent of its SS load for the first half of 2023 and will self-manage the remaining 20 percent of the load obligation through the ISO-NE wholesale markets. For the second half of 2023, CLP has 20 percent of its SS load under full requirements supply contracts and intends to purchase an additional 80 percent of full requirements. None of the SS load for 2024 has been procured. CLP was unable to obtain a full requirements supply contract for its LRS load through March 2023 and will self-manage the LRS load through ISO-NE wholesale markets. CLP intends to purchase 100 percent of full requirements for LRS for the remainder of 2023, but is prepared to self-manage the LRS load if CLP is unable to obtain full requirements supply contracts for LRS. ELECTRIC DISTRIBUTION MASSACHUSETTS NSTAR ELECTRIC COMPANY NSTAR Electric's distribution business consists primarily of the purchase, delivery and sale of electricity to its residential, commercial and industrial customers. As of December 31, 2022, NSTAR Electric furnished retail franchise electric service to approximately 1.47 million customers in 140 cities and towns in eastern and western Massachusetts, including Boston, Cape Cod, Martha's Vineyard and the greater Springfield metropolitan area, covering an aggregate area of approximately 3,200 square miles. NSTAR Electric does not own any generating facilities that are used to supply customers, and purchases its energy requirements from competitive energy suppliers. NSTAR Electric owns, operates and maintains a total of 70 MW of solar power facilities on twenty-two sites in Massachusetts. NSTAR Electric sells energy from these facilities into the ISO-NE market, with proceeds credited to customers. Rates NSTAR Electric is subject to regulation by the Massachusetts Department of Public Utilities (DPU), which, among other things, has jurisdiction over rates, certain dispositions of property and plant, mergers and consolidations, issuances of long-term securities, acquisition of securities, standards of service and construction and operation of facilities. The present general rate structure for NSTAR Electric consists of various rate and service classifications covering residential, commercial and industrial services. Under Massachusetts law, all customers of NSTAR Electric are entitled to choose their energy suppliers, while NSTAR Electric remains their electric distribution company. For those customers who do not choose a competitive energy supplier, NSTAR Electric purchases power from competitive suppliers on behalf of, and passes the related cost without mark-up through to, those customers (basic service). Electric distribution companies in Massachusetts are required to obtain and resell power to retail customers through basic service for those who choose not to buy energy from a competitive energy supplier. NSTAR Electric charges customers only the amount that it pays generators for producing electricity and does not earn a profit on the cost of electricity. The rates established by the DPU for NSTAR Electric are comprised of the following: A basic service charge that represents the collection of energy costs incurred as a result of providing electric generation service supply to all customers who have not migrated to competitive energy suppliers, including costs related to charge-offs of uncollectible energy costs from customers. Basic service rates are reset every six months (every three months for large commercial and industrial customers). Additionally, the DPU has authorized NSTAR Electric to recover the cost of its NSTAR Green wind contracts through the basic service charge. Basic service costs are reconciled annually, with any differences refunded to, or recovered from, customers. A distribution charge, which includes a fixed customer charge and a demand and/or energy charge to collect the costs of building and expanding the distribution infrastructure to deliver electricity to its destination, as well as ongoing operating costs. A revenue decoupling adjustment that reconciles annual base distribution rate recovery amounts recovered from customers to the pre-established level of baseline distribution delivery service revenue requirement approved by the DPU. Annual base distribution amounts are adjusted for inflation and filed for approval by the DPU on an annual basis, until the next rate case. A transmission charge that recovers the cost of transporting electricity over high-voltage lines from generating plants to substations, including costs allocated by ISO-NE to maintain the wholesale electric market. The transmission charge is reconciled annually to actual costs incurred, and reviewed by the DPU, with any difference refunded to, or recovered from, customers. A transition charge that represents costs to be collected primarily from previously held investments in generating plants, costs related to existing above-market power contracts, and contract costs related to long-term power contract buy-outs. The transition charge is reconciled annually to actual costs incurred, and reviewed by the DPU, with any difference refunded to, or recovered from, customers. A renewable energy charge that represents a legislatively-mandated charge to support the Massachusetts Renewable Energy Trust Fund. An energy efficiency charge that represents a legislatively-mandated charge to collect costs for energy efficiency programs. The energy efficiency charge is reconciled annually to actual costs incurred, and reviewed by the DPU, with any difference refunded to, or recovered from, customers. Reconciling adjustment charges that recover certain DPU-approved costs, including pension and PBOP benefits, low income customer discounts, credits issued to net-metering facilities installed by customers, payments to solar facilities qualified under the state solar renewable energy target program, attorney general consultant expenses, long-term renewable contracts, company-owned solar facilities, vegetation management costs, storm restoration, credits related to the Tax Cuts and Jobs Act of 2017, grid modernization costs, advanced metering infrastructure costs, electric vehicle make-ready infrastructure costs and provisional system planning charges. These charges are reconciled annually to actual costs incurred, and reviewed by the DPU, with any difference refunded to, or recovered from, customers. As approved by the DPU, NSTAR Electric has signed long-term commitments for the purchase of energy from renewable energy facilities. Distribution Rate Case : NSTAR Electric distribution rates were established in a November 2022 DPU-approved rate case, with rates effective January 1, 2023. The DPU approved a renewal of the performance-based ratemaking (PBR) plan originally authorized in its last rate case for a five-year term, with a corresponding stay out provision. The PBR plan term has the possibility of a five-year extension. The PBR mechanism allows for an annual adjustment to base distribution rates for inflation, exogenous events and future capital additions based on a historical five-year average of total capital additions. For further information, see "Regulatory Developments and Rate Matters - Massachusetts" in the accompanying Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations. Service Quality Metrics : NSTAR Electric is subject to service quality (SQ) metrics that measure safety, reliability and customer service, and could be required to pay to customers a SQ charge of up to 2.5 percent of annual transmission and distribution revenues for failing to meet such metrics. NSTAR Electric will not be required to pay a SQ charge for its 2022 performance as the company achieved results at or above target for all of its SQ metrics in 2022. Sources and Availability of Electric Power Supply As noted above, NSTAR Electric does not own any generation assets (other than 70 MW of solar power facilities that produce energy that is sold into the ISO-NE market) and purchases its energy supply requirements from a variety of competitive sources through requests for proposals issued periodically, consistent with DPU regulations. As approved by the DPU, NSTAR Electric enters into supply contracts for basic service for approximately 35 percent of its residential and 25 percent of its small commercial and industrial (CI) customers twice per year for twelve-month terms. NSTAR Electric enters into supply contracts for basic service for 11 percent of its large CI customers every three months. During 2022, NSTAR Electric supplied approximately 18 percent of its overall customer load at basic service rates. The remaining 82 percent of its overall customer load was served either by municipal aggregation or competitive supply. Because customer migration is limited to energy supply service, it has no impact on NSTAR Electrics electric distribution business or operating income of NSTAR Electric. ELECTRIC DISTRIBUTION NEW HAMPSHIRE PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE PSNH's distribution business consists primarily of the purchase, delivery and sale of electricity to its residential, commercial and industrial customers. As of December 31, 2022, PSNH furnished retail franchise electric service to approximately 535,000 retail customers in 211 cities and towns in New Hampshire, covering an area of approximately 5,630 square miles. PSNH does not own any electric generation facilities. Rates PSNH is subject to regulation by the New Hampshire Public Utilities Commission (NHPUC), which, among other things, has jurisdiction over rates, certain dispositions of property and plant, mergers and consolidations, issuances of securities, standards of service and construction and operation of facilities. Under New Hampshire law, all of PSNH's customers are entitled to choose competitive energy suppliers. For those customers who do not choose a competitive energy supplier, PSNH purchases power on behalf of, and passes the related cost without mark-up through to, those customers (default energy service). PSNH charges customers only the amount that it pays generators for producing electricity and does not earn a profit on the cost of electricity. The rates established by the NHPUC for PSNH are comprised of the following: A default energy service charge recovers energy-related costs incurred as a result of providing electric generation service supply to all customers who have not migrated to competitive energy suppliers. A distribution charge, which includes kilowatt-hour and/or demand-based charges to recover costs related to the maintenance and operation of PSNH's infrastructure to deliver power to its destination, as well as power restoration and service costs. It also includes a customer charge to collect the cost of providing service to a customer; such as the installation, maintenance, reading and replacement of meters and maintaining accounts and records. A transmission charge that recovers the cost of transporting electricity over high-voltage lines from generating plants to substations, including costs allocated by ISO-NE to maintain the wholesale electric market. A Stranded Cost Recovery Charge (SCRC), which allows PSNH to recover its stranded costs, including above-market expenses incurred under mandated power purchase obligations, other long-term investments and obligations, and the remaining costs associated with the 2018 sales of its generation facilities. A Systems Benefits Charge (SBC), which funds energy efficiency programs for all customers, as well as assistance programs for residential customers within certain income guidelines. A Regulatory Reconciliation Adjustment (RRA) that reconciles the difference between certain estimated and actual costs included in base distribution rates, including costs related to regulatory assessments, vegetation management program expenses, property tax expenses, storm cost amortization updated for the actual cost of long-term debt and lost base revenues related to net metering. As approved by the NHPUC, PSNH has signed long-term commitments for the purchase of energy from renewable energy facilities. The default energy service charge changes semi-annually, the SCRC rate changes annually with the option to change semi-annually beginning in 2023, and the transmission and SBC rates change annually. These rates are reconciled annually in accordance with the policies and procedures of the NHPUC, with any differences refunded to, or recovered from, customers. Distribution Rate Case : PSNHs distribution rates were established in a December 2020 NHPUC-approved settlement agreement, with rates effective January 1, 2021. PSNH was also permitted three step increases, effective January 1, 2021, August 1, 2021, and August 1, 2022, to reflect plant additions in calendar years 2019, 2020 and 2021, respectively. On October 20, 2022, the NHPUC approved the third step adjustment for 2021 plant in service to recover a revenue requirement of $8.9 million, with rates effective November 1, 2022. The total approved revenue requirement increase is being collected over the remainder of the rate year (November 1, 2022 July 31, 2023). Sources and Availability of Electric Power Supply PSNH does not own any generation assets and as approved by the NHPUC, purchases energy supply from a variety of competitive suppliers for its energy service customers through requests for proposals issued twice per year, for six-month terms, for approximately 81 percent of its residential and small CI customers and for 17 percent of its large CI customers. During 2022, PSNH supplied approximately 48 percent of its customer load at default energy service rates while the other 52 percent of its customer load had migrated to competitive energy suppliers. Because this customer migration is only for energy supply service, it has no impact on PSNHs electric distribution business or its operating income. ELECTRIC TRANSMISSION SEGMENT CLP, NSTAR Electric and PSNH each own and maintain transmission facilities that are part of an interstate power transmission grid over which electricity is transmitted throughout New England. Each of CLP, NSTAR Electric and PSNH, and most other New England utilities, are parties to a series of agreements that provide for coordinated planning and operation of the region's transmission facilities and the rules by which they acquire transmission services. Under these arrangements, ISO-NE, a non-profit corporation whose board of directors and staff are independent of all market participants, serves as the regional transmission organization of the New England transmission system. Wholesale Transmission Rates Wholesale transmission revenues are recovered through FERC-approved formula rates. Annual transmission revenue requirements include recovery of transmission costs and include a return on equity applied to transmission rate base. Transmission revenues are collected from New England customers, including distribution customers of CLP, NSTAR Electric and PSNH. The transmission rates provide for an annual true-up of estimated to actual costs. The financial impacts of differences between actual and estimated costs are deferred for future recovery from, or refund to, transmission customers. Transmission Rate Base Transmission rate base under our FERC-approved tariff primarily consists of our investment in transmission net utility plant less accumulated deferred income taxes. Under our FERC-approved tariff, investments in net utility plant generally enter rate base after they are placed in commercial operation. At the end of 2022, our estimated transmission rate base was approximately $9.2 billion, including approximately $4.0 billion at CLP, $3.7 billion at NSTAR Electric, and $1.5 billion at PSNH. FERC ROE Complaints Four separate complaints were filed at the FERC by combinations of New England state attorneys general, state regulatory commissions, consumer advocates, consumer groups, municipal parties and other parties (collectively, the Complainants). In each of the first three complaints, filed on October 1, 2011, December 27, 2012, and July 31, 2014, respectively, the Complainants challenged the NETOs' base ROE of 11.14 percent that had been utilized since 2005 and sought an order to reduce it prospectively from the date of the final FERC order and for the separate 15-month complaint periods. In the fourth complaint, filed April 29, 2016, the Complainants challenged the NETOs' base ROE billed of 10.57 percent and the maximum ROE for transmission incentive (incentive cap) of 11.74 percent, asserting that these ROEs were unjust and unreasonable. In response to appeals of the FERC decision in the first complaint filed by the NETOs and the Complainants, the U.S. Court of Appeals for the D.C. Circuit (the Court) issued a decision on April 14, 2017 vacating and remanding the FERC's decision. On October 16, 2018, FERC issued an order on all four complaints describing how it intends to address the issues that were remanded by the Court. FERC proposed a new framework to determine (1) whether an existing ROE is unjust and unreasonable and, if so, (2) how to calculate a replacement ROE. During 2019 and 2020, FERC has also issued multiple decisions in two pending transmission ROE complaints against the Midcontinent ISO (MISO) transmission owners, in which FERC adopted new methodologies for determining base ROEs. On August 9, 2022, the Court issued a decision vacating these decisions and remanded to FERC to reopen the proceedings.

At this time, Eversource cannot predict how and when FERC will address the Courts findings on the remand of the MISO FERC opinions or any potential associated impact on the NETOs four pending ROE complaint cases. Given the significant uncertainty regarding the applicability of the FERC opinions in the MISO transmission owners' two complaint cases to the NETOs' pending four complaint cases, Eversource concluded that there is no reasonable basis for a change to the reserve or recognized ROEs for any of the complaint periods at this time. As well, Eversource cannot reasonably estimate a range of loss for any of the four complaint proceedings at this time. For further information, see "FERC Regulatory Matters - FERC ROE Complaints" in the accompanying Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations. NATURAL GAS DISTRIBUTION SEGMENT On October 9, 2020, Eversource acquired certain assets and liabilities that comprised the NiSource Inc. (NiSource) natural gas distribution business in Massachusetts, which was previously doing business as Columbia Gas of Massachusetts (CMA), pursuant to an asset purchase agreement (the Agreement) entered into on February 26, 2020 between Eversource and NiSource. The cash purchase price was $1.1 billion, plus a working capital amount of $68.6 million, as finalized in 2021. The natural gas distribution assets acquired from CMA were assigned to Eversource Gas Company of Massachusetts (EGMA), an indirect wholly-owned subsidiary of Eversource formed in 2020. The LNG assets acquired from CMA were assigned to Hopkinton LNG Corp, also a subsidiary of Eversource. NSTAR Gas distributes natural gas to approximately 306,000 customers in 52 communities in central and eastern Massachusetts covering 1,104 square miles. EGMA distributes natural gas to approximately 333,000 customers in 65 communities throughout Massachusetts covering 1,206 square miles. Yankee Gas distributes natural gas to approximately 251,000 customers in 74 cities and towns in Connecticut covering 2,632 square miles. Total throughput (sales and transportation) in 2022 was approximately 66.1 Bcf for NSTAR Gas, 54.3 Bcf for EGMA, and 58.4 Bcf for Yankee Gas. Our natural gas businesses provide firm natural gas sales and transportation service to eligible retail customers who require a continuous natural gas supply throughout the year, such as residential customers who rely on natural gas for heating, hot water and cooking needs, as well as commercial and industrial customers who rely on natural gas for space heating, hot water, cooking and commercial and industrial applications. NSTAR Gas, EGMA and Yankee Gas generate revenues primarily through the sale and/or transportation of natural gas. All NSTAR Gas and EGMA retail customers have the ability to choose to purchase gas from third party marketers under the Massachusetts Retail Choice program. In the past year in Massachusetts, Retail Choice represented only approximately one percent of the total residential load, while Retail Choice represented approximately 56 percent of the total commercial and industrial load. Retail natural gas service in Connecticut is partially unbundled: residential customers in Yankee Gas' service territory buy natural gas supply and delivery only from Yankee Gas while commercial and industrial customers may choose their natural gas suppliers. For customers who purchase natural gas from NSTAR Gas, EGMA and Yankee Gas, the purchased natural gas commodity cost is passed through to those customers without mark-up. NSTAR Gas, EGMA and Yankee Gas do not earn a profit on the cost of purchased gas. Firm transportation service is offered to customers who purchase natural gas from sources other than NSTAR Gas, EGMA or Yankee Gas. NSTAR Gas and EGMA have the ability to offer interruptible transportation and interruptible natural gas sales service to high volume commercial and industrial customers. Yankee Gas offers interruptible transportation and interruptible natural gas sales service to commercial and industrial customers who have the ability to switch from natural gas to an alternate fuel on short notice. NSTAR Gas, EGMA and Yankee Gas can interrupt service to these customers during peak demand periods or at any other time to maintain distribution system integrity. A portion of the storage of natural gas supply for NSTAR Gas and EGMA during the winter heating season is provided by Hopkinton LNG Corp., an indirect, wholly-owned subsidiary of Eversource Energy. NSTAR Gas has access to facilities consisting of an LNG liquefaction and vaporization plant and three above-ground cryogenic storage tanks having an aggregate capacity of 3.0 Bcf of liquefied natural gas and facilities that include additional storage capacity of 0.5 Bcf. Total vaporization capacity of these facilities is 0.21 Bcf per day. EGMA has access to approximately 1.8 Bcf of LNG and 0.1 Bcf of LPG storage, with a total vaporization capacity of 0.14 Bcf per day. Yankee Gas owns a 1.2 Bcf LNG facility, which also has the ability to liquefy and vaporize up to 0.1 Bcf per day. This facility is used primarily to assist Yankee Gas in meeting its supplier-of-last-resort obligations and also enables it to provide economic supply and make economic refill of natural gas, typically during periods of low demand. Rates NSTAR Gas and EGMA are subject to regulation by the DPU and Yankee Gas is subject to regulation by the PURA, both of which, among other things, have jurisdiction over rates, certain dispositions of property and plant, mergers and consolidations, issuances of long-term securities, standards of service and construction and operation of facilities. Retail natural gas delivery and supply rates are established by the DPU and the PURA and are comprised of: A distribution charge consisting of a fixed customer charge and a demand and/or energy charge that collects the costs of building, maintaining, and expanding the natural gas infrastructure to deliver natural gas supply to its customers. This also includes collection of ongoing operating costs. A seasonal cost of gas adjustment clause (CGAC) at NSTAR Gas and EGMA that collects natural gas supply costs, pipeline and storage capacity costs, costs related to charge-offs of uncollected energy costs and working capital related costs. The CGAC is reset semi-annually with any difference being recovered from, or refunded to, customers during the following corresponding season. In addition, NSTAR Gas and EGMA file interim changes to the CGAC factor when the actual costs of natural gas supply vary from projections by more than five percent. A Purchased Gas Adjustment (PGA) clause at Yankee Gas that collects the costs of the procurement of natural gas for its firm and seasonal customers. The PGA is evaluated monthly. Differences between actual natural gas costs and collection amounts from September 1st through August 31st of each PGA year are deferred and then recovered from, or refunded to, customers during the following PGA year. Carrying charges on outstanding balances are calculated using Yankee Gas' weighted average cost of capital in accordance with the directives of the PURA. A local distribution adjustment clause (LDAC) at NSTAR Gas and EGMA that collects all energy efficiency and related program costs, environmental costs, pension and PBOP related costs, attorney general consultant costs, credits related to the Tax Cuts and Jobs Act of 2017, gas system enhancement program (GSEP) costs, costs associated with low income customers, and costs associated with a geothermal pilot program. The LDAC is reset annually with any difference being recovered from, or refunded to, customers during the following period and provides for the recovery of certain costs applicable to both sales and transportation customers. A Conservation Adjustment Mechanism (CAM) at Yankee Gas, which allows 100 percent recovery of conservation costs through this mechanism including program incentives to promote energy efficiency. A reconciliation of CAM revenues to expenses is performed annually with any difference being recovered from, or refunded to, customers with carrying charges during the following year. A Gas System Improvement (GSI) reconciliation mechanism at Yankee Gas, which collects the costs of certain Distribution Integrity Management Program (DIMP) and core capital plant in service above and beyond the level that is recovered through the distribution charge. The GSI is adjusted and reconciled annually, with any differences refunded to, or recovered from, customers. A System Expansion Rate (SER) reconciliation mechanism at Yankee Gas, which compares distribution system expansion investment costs and revenues for new customers, with the level projected in current distribution customer rates. This reconciliation is performed annually and customer rates are adjusted accordingly. A Revenue Decoupling Mechanism (RDM) at NSTAR Gas and EGMA that reconciles annual base distribution rate recovery amounts recovered from customers to the pre-established level of baseline distribution delivery service revenue requirement approved by the DPU. The pre-established level of baseline distribution delivery service revenue requirement is also subject to adjustment in accordance with provisions of the November 2020 NSTAR Gas distribution rate case and the October 2020 EGMA rate settlement agreement. A RDM at Yankee Gas that reconciles annual base distribution rate recovery amounts recovered from customers to the pre-established level of baseline distribution delivery service revenue requirement approved by PURA. The pre-established level of baseline distribution delivery service revenue requirement is also subject to adjustment in accordance with provisions of the 2018 rate case settlement agreement. Distribution Rate Cases : NSTAR Gas: NSTAR Gas distribution rates were established in an October 2020 DPU-approved rate case, with rates effective November 1, 2020. The DPU also approved a 10-year performance-based ratemaking plan through November 1, 2030, which includes inflation-based adjustments to annual base distribution amounts effective annually beginning November 1, 2021. EGMA: EGMAs distribution rates were established in a DPU-approved October 7, 2020 rate settlement agreement, with rate increases on November 1, 2021 and November 1, 2022, and two rate base resets during an eight-year rate plan, occurring on November 1, 2024 and November 1, 2027. Notwithstanding the two distribution rate increases, the two rate base reset provisions, and potential adjustments for qualifying exogenous events, EGMA agreed not to file for an increase or redesign of distribution base rates effective prior to November 1, 2028. Yankee Gas: Yankee Gas distribution rates were established in a December 2018 PURA-approved rate case settlement agreement, with rates effective November 15, 2018. PURA also approved step adjustments effective January 1, 2019, January 1, 2020 and March 1, 2021. Service Quality Metrics : NSTAR Gas and EGMA are subject to SQ metrics that measure safety, reliability and customer service and each could be required to pay to customers a SQ charge of up to 2.5 percent of annual distribution revenues for failing to meet such metrics. NSTAR Gas and EGMA will not be required to pay an SQ charge for their 2022 performance as each achieved results at or above target for all of their SQ metrics in 2022. Natural Gas Replacement Massachusetts: Pursuant to Massachusetts legislation, in October of each year, NSTAR Gas and EGMA file GSEP Plans with the DPU for the following construction year. The GSEP Program is designed to accelerate the replacement of certain natural gas distribution facilities in the system to less than 25 years. The GSEP includes a tariff that provides NSTAR Gas and EGMA an opportunity to collect the costs for the program on an annual basis through a reconciling factor. On April 30th each year, the DPU approves the GSEP rate recovery factor that goes into effect on May 1st. In October 2020, the DPU opened Docket DPU 20-80 The Future of Gas to examine the role of Massachusetts natural gas local distribution companies (LDCs) in helping to meet the states 2050 climate goals. The DPU will consider new policies and structures that would protect customers as Massachusetts works to decarbonize the building sector, potentially recasting the role of LDCs in Massachusetts, which may require significant changes to the LDCs planning processes and business models. At this time, Eversource cannot predict the ultimate outcome of this proceeding and the resulting impact to its natural gas businesses, however the Company does not believe there is any indication of an inability to recover costs or risk of impairment of our natural gas assets at this time. Connecticut: Yankee Gas' December 2018 PURA-approved rate case settlement agreement included an accelerated pipeline replacement cost recovery program. The Gas System Improvement (GSI) rate recovers accelerated pipeline replacement as well as other capital investment through an annual reconciliation. Yankee Gas files its GSI reconciliation annually on March 1st for rates effective April 1st. In September 2021, PURA undertook a review of Connecticut natural gas companies infrastructure system expansion plan (SEP) to determine if the SEP continues to be in the best interest of the states comprehensive energy strategy. On April 27, 2022, PURA issued an order for the immediate winding down of the SEP by (1) ending the enrollment of new customers in the SEP program and permitting only a specific group of potential customers who have executed a services agreement with a natural gas company on or before a specified date (subsequently approved as August 16, 2022) to qualify for incentives under the current SEP; (2) directing all surplus non-firm margin to be deferred as a regulatory liability and applied to rate base in a future rate proceeding; and (3) directing the natural gas companies to cease all outbound and passive marketing regarding the SEP. On July 15, 2022, Eversource appealed the portion of this order pertaining to the deferral of non-firm margin as a reduction to future rate base. Eversource evaluated the prospective impact of this proceeding and does not believe the impact will be material to its future financial position, results of operations and cash flows. Sources and Availability of Natural Gas Supply NSTAR Gas maintains a flexible resource portfolio consisting of natural gas supply contracts, transportation contracts on interstate pipelines, market area storage and peaking services. NSTAR Gas purchases transportation, storage, and balancing services from Tennessee Gas Pipeline Company and Algonquin Gas Transmission Company, as well as other upstream pipelines that transport natural gas from major natural gas producing regions in the U.S., including the Gulf Coast, Mid-continent region, and Appalachian Shale supplies to the final delivery points in the NSTAR Gas service area. NSTAR Gas purchases all of its natural gas supply under a firm, competitively bid annual portfolio management contract. In addition to the firm transportation and natural gas storage supplies discussed above, NSTAR Gas utilizes on-system LNG facilities to meet its winter peaking demands. These LNG facilities are located within NSTAR Gas' distribution system and are used to liquefy and store pipeline natural gas during the warmer months for vaporization and use during the heating season. During the summer injection season, excess pipeline capacity and supplies are used to deliver and store natural gas in market area underground storage facilities located in Maryland and Pennsylvania. Stored natural gas is withdrawn during the winter season to supplement flowing pipeline supplies in order to meet firm heating demand. NSTAR Gas has firm underground storage contracts and total storage capacity entitlements of approximately 6.6 Bcf, and 3.5 Bcf LNG storage is provided by Hopkinton LNG Corp. in facilities located in two different locations in Massachusetts. EGMA maintains a flexible resource portfolio consisting of natural gas supply contracts, transportation contracts on interstate pipelines, market area storage and peaking services. EGMA purchases transportation, storage, and balancing services from Tennessee Gas Pipeline Company and Algonquin Gas Transmission Company, as well as other upstream pipelines that transport natural gas from major natural gas producing regions in the U.S. as well as Canada, including the Gulf Coast, Mid-continent region, Appalachian Shale, and Dawn, Ontario supplies to the final delivery points in the EGMA service area. EGMA purchases the majority of its natural gas supply under a number of firm, competitively bid annual portfolio management contracts and manages a portion of its portfolio itself. In addition to the firm transportation and natural gas storage supplies discussed above, EGMA utilizes on-system LNG and LPG facilities to meet its winter peaking demands. These LNG and LPG facilities are located within EGMAs distribution system and are used to liquefy pipeline natural gas and/or receive liquefied natural gas or liquefied petroleum gas to be stored during the warmer months for vaporization and use during the heating season. During the summer injection season, excess pipeline capacity and supplies are used to deliver and store natural gas in market area underground storage facilities located in Maryland and Pennsylvania. Stored natural gas is withdrawn during the winter season to supplement flowing pipeline supplies in order to meet firm heating demand. EGMA has firm underground storage contracts and total storage capacity entitlements of approximately 8.6 Bcf, and 1.9 Bcf LNG and LPG storage is provided by Hopkinton LNG Corp. in facilities located at seven different locations in Massachusetts. PURA requires Yankee Gas to meet the needs of its firm customers under all weather conditions. Specifically, Yankee Gas must structure its supply portfolio to meet firm customer needs under a design day scenario (defined as the coldest day in 30 years) and under a design year scenario (defined as the average of the four coldest years in the last 30 years). Yankee Gas also maintains a flexible resource portfolio consisting of natural gas supply contracts, transportation contracts on interstate pipelines, off-system storage and its on-system 1.2 Bcf LNG storage facility in Connecticut to meet consumption needs during the coldest days of winter. Yankee Gas obtains its interstate capacity from the three interstate pipelines that directly serve Connecticut: the Algonquin, Tennessee and Iroquois Pipelines, which connect to other upstream pipelines that transport natural gas from major natural gas producing regions, including the Gulf Coast, Mid-continent, Canadian regions and Appalachian Shale supplies. Based on information currently available regarding projected growth in demand and estimates of availability of future supplies of pipeline natural gas, each of NSTAR Gas, EGMA and Yankee Gas believes that in order to meet the long-term firm customer requirements in a reliable manner, a combination of pipeline, storage, and non-pipeline solutions will be necessary. WATER DISTRIBUTION SEGMENT Aquarion Company (Aquarion) operates five separate regulated water utilities in Connecticut (Aquarion Water Company of Connecticut, or AWC-CT, and The Torrington Water Company), Massachusetts (Aquarion Water Company of Massachusetts, or AWC-MA), and New Hampshire (Aquarion Water Company of New Hampshire, or AWC-NH, and Abenaki Water Company). These regulated companies provide water services to approximately 237,000 residential, commercial, industrial, municipal and fire protection and other customers, in 72 towns and cities in Connecticut, Massachusetts and New Hampshire. As of December 31, 2022, approximately 92 percent of Aquarions customers were based in Connecticut. Rates Aquarion's water utilities are subject to regulation by the PURA, the DPU and the NHPUC in Connecticut, Massachusetts and New Hampshire, respectively. These regulatory agencies have jurisdiction over, among other things, rates, certain dispositions of property and plant, mergers and consolidations, issuances of long-term securities, standards of service and construction and operation of facilities. Aquarions general rate structure consists of various rate and service classifications covering residential, commercial, industrial, and municipal and fire protection services. The rates established by the PURA, DPU and NHPUC are comprised of the following: A base rate, which is comprised of fixed charges based on meter/fire connection sizes, as well as volumetric charges based on the amount of water sold. Together these charges are designed to recover the full cost of service resulting from a general rate proceeding. In Connecticut, a revenue adjustment mechanism (RAM) that reconciles earned revenues, with certain allowed adjustments, on an annual basis, to the revenue requirement approved by PURA. In Connecticut and New Hampshire, a water infrastructure conservation adjustment (WICA) charge, and in Massachusetts, an annual main replacement adjustment mechanism (MRAM) charge, which is applied between rate case proceedings and seeks recovery of allowed costs associated with eligible infrastructure improvement projects placed in-service. The WICA is updated semi-annually in Connecticut and annually in New Hampshire. In Connecticut, an annual WICA reconciliation mechanism reconciles earned WICA revenue to the approved WICA revenue with any differences refunded to, or recovered from, customers. Sources and Availability of Water Supply Our water utilities obtain their water supplies from owned surface water sources (reservoirs) and groundwater supplies (wells) with a total supply yield of approximately 133 million gallons per day, as well as water purchased from other water suppliers. Approximately 98 percent of our annual production is self-supplied and processed at nine surface water treatment plants and numerous well stations, which are all located in Connecticut, Massachusetts, and New Hampshire. The capacities of Aquarions sources of supply, and water treatment, pumping and distribution facilities, are considered sufficient to meet the present requirements of Aquarions customers under normal conditions. On occasion, drought declarations are issued for portions of Aquarions service territories in response to extended periods of dry weather conditions. OFFSHORE WIND BUSINESS Eversource's offshore wind business includes a 50 percent ownership interest in North East Offshore, which holds power purchase agreements (PPAs) and contracts for the Revolution Wind, South Fork Wind and Sunrise Wind projects, as well as an undeveloped offshore lease area. Our offshore wind projects are being developed and constructed through a joint and equal partnership with rsted. The offshore leases include a 257 square-mile ocean lease off the coasts of Massachusetts and Rhode Island and a separate, adjacent 300 square-mile ocean lease located approximately 25 miles south of the coast of Massachusetts. In aggregate, these ocean lease sites jointly-owned by Eversource and rsted could eventually develop at least 4,000 MW of clean, renewable offshore wind energy. Revolution Wind is a 704 MW offshore wind power project located approximately 15 miles south of the Rhode Island coast, and South Fork Wind is a 130 MW offshore wind power project located approximately 35 miles east of Long Island. Sunrise Wind is a 924 MW offshore wind facility, which will be developed 35 miles east of Montauk Point, Long Island. The completion dates for these projects are subject to federal permitting through BOEM, engineering, state siting and permitting in New York, Rhode Island and Massachusetts and construction schedules. We have initiated a strategic review of our offshore wind investment portfolio. As part of that review, we are exploring strategic alternatives that could result in a potential sale of all, or part, of our 50 percent interest in our offshore wind partnership with rsted. For more information on these projects and on the strategic review, see "Business Development and Capital Expenditures Offshore Wind Business" in the accompanying Item 7, Management's Discussion and Analysis of Financial Condition and Results of

Operations . CAPITAL EXPENDITURES For information on capital expenditures and projects during 2022, as well as projected capital expenditures by business, see "Business Development and Capital Expenditures" in the accompanying Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations . FINANCING For information regarding short-term and long-term debt agreements, see "Liquidity" in the accompanying Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, and Note 8, "Short-Term Debt," and Note 9, "Long-Term Debt," of the Combined Notes to Financial Statements. NUCLEAR FUEL STORAGE CLP, NSTAR Electric, PSNH, and several other New England electric utilities are stockholders in three inactive regional nuclear generation companies, CYAPC, MYAPC and YAEC (collectively, the Yankee Companies). The Yankee Companies have completed the physical decommissioning of their respective nuclear power facilities and are now engaged in the long-term storage of their spent nuclear fuel. The Yankee Companies fund these costs through litigation proceeds received from the DOE and, to the extent necessary, through wholesale, FERC-approved rates charged under power purchase agreements with several New England utilities, including CLP, NSTAR Electric and PSNH. CLP, NSTAR Electric and PSNH, in turn recover these costs from their customers through state regulatory commission-approved retail rates. The Yankee Companies collect amounts that we believe are adequate to recover the remaining plant closure and fuel storage cost estimates for the respective plants. We believe CLP and NSTAR Electric will recover their shares of these obligations from their customers. PSNH has recovered its total share of these costs from its customers. We consolidate the assets and obligations of CYAPC and YAEC on our consolidated balance sheet because our ownership and voting interests are greater than 50 percent of each of these companies. OTHER REGULATORY AND ENVIRONMENTAL MATTERS General We are regulated by various federal and state agencies, including FERC, the SEC, and various state and/or local regulatory authorities with jurisdiction over the industry and the service areas in which each of our companies operates, including the PURA, which has jurisdiction over CLP, Yankee Gas, and Aquarion, the DPU, which has jurisdiction over NSTAR Electric, NSTAR Gas, EGMA and Aquarion, and the NHPUC, which has jurisdiction over PSNH and Aquarion. Renewable Portfolio Standards Each of the states in which we do business has Renewable Portfolio Standards (RPS) requirements, which generally require fixed percentages of our energy supply to come from renewable energy sources such as solar, wind, hydropower, landfill gas, fuel cells and other similar sources. Connecticut's RPS statute requires increasing percentages of the electricity sold to retail customers to have direct ties to renewable sources. In 2022, the total RPS obligation was 33.0 percent and will ultimately reach 48.0 percent in 2030. CLP is permitted to recover any costs incurred in complying with RPS from its customers through its generation service charge rate. Massachusetts' RPS program requires electricity suppliers to meet renewable energy standards. For 2022, the RPS and Clean Energy Standard (CES) requirements were 51.3 percent, and will ultimately reach 64.3 percent in 2025. Massachusetts electric suppliers were also required to meet Alternative Energy Portfolio Standards (APS) of 5.5 percent and Clean Peak Energy Standards (CPS) of 4.5 percent in 2022. Those requirements will reach 6.25 and 9.00 percent in 2025, respectively. NSTAR Electric is permitted to recover any costs incurred in complying with these requirements from its customers through rates. NSTAR Electric also owns renewable solar power facilities. The RECs generated from NSTAR Electric's solar power facilities are sold to other energy suppliers, and the proceeds from these sales are credited back to customers. New Hampshire's RPS provision requires increasing percentages of the electricity sold to retail customers to have direct ties to renewable sources. In 2022, the total RPS obligation was 22.5 percent and it will ultimately reach 25.2 percent in 2025. The costs of the RECs are recovered by PSNH through rates charged to customers. Environmental Regulation and Matters We are subject to various federal, state and local environmental legislation and regulation with respect to water quality, air quality, natural/working lands (wetlands, resource areas, habitat), hazardous materials and other environmental matters. Our environmental policy includes formal procedures and a task-scheduling system in place to help ensure environmental compliance. The Boards Governance, Environmental and Social Responsibility Committee also provides oversight of climate issues, environmental matters and compliance. We also identify and address potential environmental risks through our Enterprise Risk Management (ERM) program in addition to rigorous audits of our facilities, vendors, and processes. Additionally, projects may not be constructed or significantly modified without a review of the environmental impact of the proposed construction or modification by the applicable federal or state agencies. Many of our construction projects require the submission of comprehensive permitting applications to various local, state and federal agencies. The permits we receive outline various best management practices and restoration requirements to address construction period-impacts. We have recorded a liability for what we believe, based upon currently available information, is our reasonably estimable environmental investigation, remediation, and/or natural resource damages costs for waste disposal sites for which we have probable liability. Under federal and state law, government agencies and private parties can attempt to impose liability on us for recovery of investigation and remediation costs at contaminated sites. As of December 31, 2022, the liability recorded for our reasonably estimable and probable environmental remediation costs for known sites needing investigation and/or remediation, exclusive of recoveries from insurance or from third parties, was $122.6 million, representing 59 sites. These costs could be significantly higher if additional remediation becomes necessary or when additional information as to the extent of contamination becomes available. The most significant liabilities currently relate to future clean-up costs at former MGP facilities. These facilities were owned and operated by our predecessor companies from the mid-1800's to mid-1900's. By-products from the manufacture of natural gas using coal resulted in fuel oils, hydrocarbons, coal tar, purifier wastes, metals and other waste products that may pose a potential risk to human health and the environment. We currently have partial or full ownership responsibilities at former MGP sites that have a reserve balance of $112.6 million of the total $122.6 million as of December 31, 2022. MGP costs are recoverable through rates charged to our customers. When planning environmental investigations and remediation of impacted properties, we work closely with the municipalities and environmental regulators to ensure that our remediation plans adhere to applicable regulations while protecting human health and the environment. In many cases, these remediation projects are designed to address opportunities for beneficial reuse of the property. Global Climate Change and Greenhouse Gas Emission Issues We assess the regulatory, physical and transitional impacts related to climate change to develop mitigation strategies including evaluating the impacts of more severe weather events, financial risks, changing customer behaviors, and opportunities to reduce emissions in our operations and for the region through clean energy and emerging technologies investments. Regulatory Impacts of Climate Change: Global climate change continues to receive increasing focus from the federal and state governments. The Biden administration has communicated a strong focus on addressing climate change by setting a U.S. target of reducing greenhouse gas (GHG) emissions by 50 percent by 2030, compared to 2005 levels, and achieving net-zero emissions by 2050 economy-wide. The plan calls for aggressive measures focused on clean transportation, clean energy and climate investments targeted at environmental justice communities. In support of this plan, federal funding and incentive programs for clean transportation and energy offer opportunities for Eversource to invest in projects that have the ability to reduce emissions in the region while benefiting our communities and shareholders. Similarly, some of the states in which we operate have aggressive climate goals and implementation plans. In Connecticut, legislation includes a target to achieve zero-carbon electricity by 2040. In response to 2021 climate legislation, in 2022, Massachusetts finalized sub-limits for the transportation, building and electricity sectors, among others, in support of the states net zero emissions target by 2050. These state regulations and related policies may introduce risks and opportunities to our businesses if demands for energy or heating change or if investment opportunities for new projects present themselves. We are continually evaluating the evolving regulatory landscape concerning climate change, which could potentially lead to additional requirements and additional rules and regulations that could impact how we operate our businesses. Potential future environmental statutes and regulations, such as additional greenhouse gas reduction regulations to address global climate change, could impose significant additional costs and there can be no assurance that regulators will approve the recovery of those costs. Physical and Transitional Impacts of Climate Change: Eversource assesses the physical impacts of climate change that are event-driven or due to longer-term shifts in climate patterns, as well as transitional impacts related to a shift to a lower-carbon economy and changes to address mitigation and adaptation requirements. To address physical and transitional impacts related to climate change, maintain resiliency across our system, and enable potential opportunities for our business, we are pursuing the following actions: Improving our system resiliency in response to climate change through vegetation management, pole and wire strengthening, flood proofing, and other system hardening measures; Implementing a grid modernization plan that will enhance our electric distribution infrastructure to improve resiliency and reliability and increase opportunities to facilitate integration of distributed energy resources and electric vehicle infrastructure; Focusing on improving the efficiency of our electric and natural gas distribution systems, preparing for increased opportunities that clean energy advancements create, and providing customers with ways to optimize their energy efficiency; Investigating emerging technologies such as energy storage and automation programs that improve reliability; Implementing programs to address risks that may impact water availability and water quality; and Evaluating opportunities for our natural gas system and exploring alternative, less carbon-intense, technologies like renewable natural gas and geothermal for heating. Physical risks from climate change may result from sea level rise and shifting weather conditions, such as changes in precipitation, extreme heat, more frequent and severe storms, droughts and floods. These risks may result in customers energy and water usage increasing or decreasing depending on the duration and magnitude of the changes, degradation of water quality and our ability to reliably deliver our services to customers. Severe weather may cause outages, potential disruption of operations, and property damage to our operating facilities. Our actions to improve system reliability and resiliency allow our business to operate under changing conditions and meet customer expectations. System improvements are designed to withstand severe weather impacts and include installing new and stronger infrastructure like poles, wires and related system equipment, as well as enhanced year-round tree trimming. We are reinforcing existing critical facilities to withstand storm surges and all future substations are being flood hardened to better protect our system against storm surges associated with the increasing risk of severe weather. We created our comprehensive emergency preparedness and response plans in partnership with state and community leaders so that when a storm occurs, we can provide customers and municipalities with timely and accurate information, while safely and promptly restoring power. Additionally, we collaborate with other utility providers and industry partners across the country to better understand storm hazards and develop solutions to improve our system reliability. We have made a corporate commitment to reduce Scope 1 and 2 greenhouse gas emissions from our operations and reach carbon neutrality by 2030. In November 2022, we committed to setting a science-based target within the next two years, which will expand our emission reduction efforts to include indirect Scope 3 sources. Greenhouse gas emissions from our operations consist primarily of line loss (emissions associated with the energy lost when power is transmitted and distributed across the electric system), methane leaks from our natural gas distribution system, operating our facilities and vehicle fleet, and sulfur hexafluoride (SF_6) leaks from electric equipment. To measure our influences on climate change, we quantify and publicly report our operational carbon footprint through a third-party verified GHG emission inventory on an annual basis. Our initiatives to reduce GHG emissions across our company include improving energy efficiency and expanding the use of renewable energy at our buildings, utilizing alternative fuels and introducing more hybrid vehicles into the company fleet, cutting fugitive emissions of methane and SF6 by replacing leaky natural gas pipes, improving maintenance of electrical equipment, and piloting innovative technologies. Our business is also transitioning in response to climate change and we are enabling broad decarbonization of the electrical and building sectors in support of regional policies and targets. We actively support local, state and federal emission reduction goals to address climate change and pursue climate-related opportunities that enable continued business success while serving the needs of our customers. Our clean energy investments help reduce regional emissions while improving shareholder value. Meanwhile, our energy efficiency solutions and electric vehicle infrastructure investments allow our customers to make choices that minimize climate-related impacts. Additionally, as our business transitions to support a low carbon economy, human capital needs will also change with the potential to impact our workforce. As new technologies are implemented, we will need to recruit, develop and possibly retrain employees to meet the need for new skill sets. Electric and Magnetic Fields For more than forty years, published reports have discussed the possibility of adverse health effects from electric and magnetic fields (EMF) associated with electric transmission and distribution facilities, including appliances, and wiring in buildings and homes. Some epidemiology studies have reported a possible statistical association between adverse health effects and exposure with EMF. The association identified in some of these studies remain unexplained and inconclusive. Numerous scientific review panels, considering all significant EMF epidemiology and laboratory studies, have concluded that the available body of scientific information does not support a conclusion that EMF affects human health at levels expected in the vicinity. In accordance with recommendations of various regulatory bodies and public health organizations, we use design principles that help reduce potential EMF exposures associated with new transmission lines. HUMAN CAPITAL Eversource is committed to delivering reliable energy and superior customer service; expanding energy options for our region; environmental stewardship; a safe, diverse and fairly-compensated workforce; and community service and leadership. Our employees are critical to achieving this mission and we recognize the importance of attracting, retaining, growing and developing our employees. Leaders at all levels strive to create a workplace where our employees are engaged, advocate for the customer, work collaboratively, raise ideas for improvement and focus on delivering a superior customer experience. We build employee engagement through continuous communication, developing talent, fostering teamwork and creating a diverse, equitable and inclusive workplace. As of December 31, 2022, Eversource Energy employed a total of 9,626 employees, excluding temporary employees, of which 1,444 were employed by CLP, 1,648 were employed by NSTAR Electric, and 796 were employed by PSNH. In addition, 3,664 were employed by Eversource Service, Eversource's service company, that provides support services to all Eversource operating companies. Approximately 50 percent of our employees are members of the International Brotherhood of Electrical Workers, the Utility Workers Union of America or The United Steelworkers, and are covered by 13 collective bargaining agreements. Safety. At Eversource, our commitment to Safety First and Always is a principle and a mindset present in every job and every task, whether in the field, office or at home. A priority at Eversource is continuous improvement and safety is at the forefront as we continue to build a strong safety culture, embrace new technologies, and learn with our industry and community partners to improve safety performance. We use metrics such as Eversource Corporate Days Away Restricted Time (DART) and Preventable Motor Vehicle events, among others, to monitor safety performance. Our DART safety performance was 1.0 in 2022, measured by days away, restricted or transferred per 100 workers, using the DART-OSHA method of measurement. Diversity, Equity Inclusion. Our commitment to Diversity, Equity Inclusion (DEI) is critical to building a diverse, empowered and engaged team that delivers great service safely to our customers. A diverse workforce and inclusive culture contribute to our success and sustainability by driving innovation and creating trusted relationships with our employees, customers, suppliers and community partners. We continue to identify and support many programs and agencies that address racial and ethnic disparities in our communities and beyond. We also remain committed to developing a workforce that fully reflects the diversity of the people and communities we serve. Our hiring practices emphasize diversity, equity and inclusion and we encourage employees to embrace different people, perspectives and experiences in our workplace and within our communities. Additionally, our leadership behaviors underscore the importance of creating inclusive teams, where employees voices and contributions are essential to delivering superior customer service. Eversource continues to develop a diverse workforce with an increased focus on women and minorities in leadership and has DEI goals and initiatives for diversity in leadership promotions and new hires, diverse external hires, diverse candidate slate, key talent, workforce representation, leadership engagement, community support and supplier spends. Eversource drives accountability for DEI progress throughout the company and executive compensation is linked to meeting these goals. We sustained our successful drive to increase workforce diversity; in 2022, 61.6% of our external hires were women and/or people of color and 45.1% percent of new hires and promotions into leadership roles were women and/or people of color. Eversources executive leadership team promotes and supports DEI by leading and building diverse, inclusive work teams with high engagement, growing a pipeline of diverse talent, leveraging multiple perspectives to improve customer service, using diverse suppliers, engaging with multicultural organizations in our communities and supporting the work of our DEI council, racial equity task force, business resource groups, and our cross-functional pro-equity advisory team, which developed and began to implement justice and equity training to all employees in 2022. Eversource's Board of Trustees is committed to diversity, equity and inclusion and receives regular monthly progress updates. The Corporate Governance, Environmental and Social Responsibility Committee of the Board of Trustees is responsible for the oversight of environmental, human capital management and social responsibility strategy, programs and policies. The Board of Trustees seeks diversity in gender, race/ethnicity and personal background when considering Trustee candidates. Compensation, Health and Wellness Benefits . We are committed to the health, safety and wellness of our employees. We provide competitive compensation and comprehensive benefit packages, including healthcare, life insurance, long-term disability insurance, death benefits, retirement plans (defined benefit pension plans or 401k Plan), an Employee Stock Purchase Plan, health savings and flexible spending accounts, paid time off, employee assistance programs, and tuition assistance, among many others. Eversource also provides wellness programs and benefits to encourage employees and their families to adopt and maintain healthy lifestyle habits. Talent Development, Training Programs and Education Opportunities. Strategic workforce plans are developed every year as part of the annual business planning process to identify immediate and long-range needs to ensure that we acquire, develop and retain diverse, capable talent. Eversource supports and develops its employees through training and development programs that build and strengthen employees leadership and skill set. Employee development programs are aligned to our strategic workforce plan to support succession within all levels of the organization. Continuous professional development is important to support our employees ongoing success. These professional development programs include leadership effectiveness programs designed to develop new and current supervisors; a talent management process to identify high potential and emerging talent and ensure their development; a rotational associate engineering program; educational and professional development opportunities for employees who are recent college graduates; tuition assistance program; and paid internships and co-ops. We leverage educational partnerships in critical trade and technical areas and have developed proactive sourcing strategies to attract experienced workers in highly technical roles in engineering, electric and gas operations, and energy efficiency. As part of this process, we identify critical roles and develop succession plans to ensure we have a capable supply of talent for the future. Community Social Impact. Eversource and our employees support many programs, agencies, and not-for-profit organizations that provide economic and community development, the environment, and initiatives that address local, high-priority concerns and needs. Eversource provides donations and other support to community agencies, including significant volunteer hours of our employees. See Item 11, Executive Compensation , included in this Annual Report on Form 10-K, as well as our 2021 Sustainability Report and our 2021 Diversity, Equity and Inclusion Report located on our website, for more detailed information regarding our human capital programs and initiatives. Nothing on our website, including our Sustainability Report, Diversity, Equity and Inclusion Report or sections thereof, shall be deemed incorporated by reference into this Annual Report. INTERNET INFORMATION Our website address is www.eversource.com. We make available through our website a link to the SEC's EDGAR website (http://www.sec.gov/edgar/searchedgar/companysearch.html), at which site

Eversource's, CLP's, NSTAR Electric's and PSNH's combined Annual Reports on Form 10-K, combined Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to those reports may be reviewed. Information contained on the Company's website or that can be accessed through the website is not incorporated into and does not constitute a part of this Annual Report on Form 10-K. Printed copies of these reports may be obtained free of charge by writing to our Investor Relations Department at Eversource Energy, 107 Selden Street, Berlin, CT 06037. Item 1A. Risk Factors In addition to the matters set forth under "Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995" included immediately prior to Item 1, Business, above, we are subject to a variety of material risks. Our susceptibility to certain risks, including those discussed in detail below, could exacerbate other risks. These risk factors should be considered carefully in evaluating our risk profile. There may be additional risks and uncertainties (either currently unknown or not currently believed to be material) that could adversely affect our financial position, results of operations, and cash flows. Cybersecurity and Data Privacy Risks: Cyberattacks, including acts of war or terrorism, targeted directly on or indirectly affecting our systems or the systems of third parties on which we rely, could severely impair operations, negatively impact our business, lead to the disclosure of confidential information and adversely affect our reputation. Cyberattacks that seek to exploit potential vulnerabilities in the utility industry and seek to disrupt electric, natural gas and water transmission and distribution systems are increasing in sophistication, magnitude and frequency. In the first quarter of 2022, the federal government notified the owners and operators of critical infrastructure that the conflict between Russia and Ukraine has increased the likelihood of a cyberattack on such systems. A successful cyberattack on the information technology systems that control our transmission, distribution, natural gas and water systems or other assets could impair or prevent us from managing these systems and facilities, operating our systems effectively, or properly managing our data, networks and programs. The breach of certain information technology systems could adversely affect our ability to correctly record, process and report financial information. A major cyber incident could result in significant expenses to investigate and to repair system damage or security breaches and could lead to litigation, fines, other remedial action, heightened regulatory scrutiny and damage to our reputation. We have instituted safeguards to protect our information technology systems and assets. We deploy substantial technologies to system and application security, encryption and other measures to protect our computer systems and infrastructure from unauthorized access or misuse. Specifically, regarding vulnerabilities, we patch systems where patches are available to deploy, and have technologies that detect exploits of vulnerabilities and proactively block the exploit when it happens. We also interface with numerous external entities to improve our cybersecurity situational awareness. The FERC, through the North American Electric Reliability Corporation (NERC), requires certain safeguards to be implemented to deter cyberattacks. These safeguards may not always be effective due to the evolving nature of cyberattacks. We maintain cyber insurance to cover damages and defense costs related to breaches of networks or operational technology, but it may be insufficient in limits and coverage exclusions to cover all losses. Any such cyberattacks could result in loss of service to customers and a significant decrease in revenues, which could have a material adverse impact on our financial position, results of operations and cash flows. The unauthorized access to, and the misappropriation of, confidential and proprietary customer, employee, financial or system operating information could adversely affect our business operations and adversely impact our reputation. In the regular course of business, we, and our third-party suppliers, rely on information technology to maintain sensitive customer, employee, financial and system operating information. We are required by various federal and state laws to safeguard this information. Cyber intrusions, security breaches, theft or loss of this information by cybercrime or otherwise could lead to the release of critical operating information or confidential customer or employee information, which could adversely affect our business operations or adversely impact our reputation, and could result in significant costs, fines and litigation. We employ system controls to prevent the dissemination of certain confidential information and periodically train employees on phishing risks. We maintain cyber insurance to cover damages and defense costs arising from unauthorized disclosure of, or failure to protect, private information, as well as costs for notification to, or for credit monitoring of, customers, employees and other persons in the event of a breach of private information. This insurance covers amounts paid to address a network attack or the disclosure of personal information, and costs of a qualified forensics firm to determine the cause, source and extent of a network attack or to investigate, examine and analyze our network to find the cause, source and extent of a data breach, but it may be insufficient to cover all losses. While we have implemented measures designed to prevent network attacks and mitigate their effects should they occur, these measures may not be effective due to the continually evolving nature of efforts to access confidential information. Business and Operational Risks: Strategic development opportunities associated with offshore wind or investment opportunities in electric transmission, distributed generation, or clean-energy opportunities may not be successful, and projects may not commence operation as scheduled or within budget, or be completed, which could have a material adverse effect on our business prospects. We are pursuing broader strategic development investment opportunities that will benefit the Northeast region related to the development, construction and operation of offshore wind electric generation facilities, and investment opportunities in electric transmission facilities, distributed generation and other clean-energy infrastructure. The states in which we provide service have implemented selection procedures for such new facilities that require the review of competing projects and permit the selection of only those projects that are expected to provide the greatest benefit to customers. Accordingly, our projects may not be selected for construction. The development and construction of projects selected for construction involves numerous significant risks including scheduling delays, increased costs, tax strategies and changes to federal tax laws, federal, state and local permitting and regulatory approval processes, specifically

BOEMs approval processes, new legislation impacting the industry, future legislative or regulatory actions that could result in these projects not being probable of entering the construction phase, economic events or factors, environmental and community concerns, design and siting issues, difficulties in obtaining required rights of way, competition from incumbent utilities and other entities, actions of our strategic partners, and capacity factors once projects are placed in operation. Also, supply constraints in New England are leading to historic increases in fuel and commodity costs which may impact our ability to accomplish our strategic objectives. Our offshore wind partnerships ability to generate returns from its offshore wind projects will depend on meeting construction schedules, controlling project costs, maintaining continuing interconnection arrangements, power purchase agreements, or other market mechanisms as well as interconnecting utility and Regional Transmission Organizations rules, policies, procedures and FERC tariffs that permit future offshore wind project operations. Additionally, scheduling or permitting delays in offshore wind projects, increases in cost estimates, higher interest rates, changes to tax laws impacting the offshore wind partnerships ability to monetize tax attributes, or the cancellation of any projects, as well as the other risk factors described above, could result in lower investment returns and, if significant enough, an impairment of the carrying value of our investment. Such an impairment could have a material adverse effect on our financial position, results of operations, and cash flows, or our future growth opportunities may not be realized as anticipated. We assess our investments (recorded as either long-lived assets or equity method investments) for impairment whenever events or circumstances indicate that the carrying amount of the investment may not be recoverable. To the extent the value of the investment becomes impaired, the impairment charge could have a material adverse effect on our financial condition and results of operations. We rely on third-party suppliers for equipment, materials, and services and we outsource certain business functions to third-party suppliers and service providers, and substandard performance or inability to fulfill obligations by those third parties could harm our business, reputation and results of operations. We outsource certain services to third parties in areas including information technology, transaction processing, human resources, payroll and payroll processing and certain operational areas. Outsourcing of services to third parties could expose us to substandard quality of service delivery or substandard deliverables, which may result in missed deadlines or other timeliness issues, non-compliance (including with applicable legal requirements and industry standards) or reputational harm, which could negatively impact our results of operations. Our contractual arrangements with these contractors typically include performance standards, progress payments, insurance requirements and security for performance. We also continue to pursue enhancements to standardize our systems and processes. The global supply chain of goods and services is currently being negatively impacted by several factors, including the geopolitical climate, labor shortages, domestic and international shipping constraints, increased demand, and shortages of raw materials. As a result, we are seeing delivery delays of certain goods. Additionally, the prices for equipment, materials, and contractor services have increased, and may continue to increase. If significant difficulties in the global supply chain cycle or inflationary impacts were to continue or worsen, they could adversely affect our results of operations, or adversely affect our ability to work with regulators, unions, customers or employees. Our transmission and distribution systems may not operate as expected, and could require unplanned expenditures, which could adversely affect our financial position, results of operations and cash flows. Our ability to properly operate our transmission and distribution systems is critical to the financial performance of our business. Our transmission and distribution businesses face several operational risks, including the breakdown, failure of, or damage to operating equipment, information technology systems, or processes, especially due to age; labor disputes; disruptions in the delivery of electricity, natural gas and water; increased capital expenditure requirements, including those due to environmental regulation; catastrophic events such as fires, explosions, a solar event, an electromagnetic event, or other similar occurrences; increasingly severe weather conditions due to climate change beyond equipment and plant design capacity; human error; global supply chain disruptions; and potential claims for property damage or personal injuries beyond the scope of our insurance coverage. Many of our transmission projects are expected to alleviate identified reliability issues and reduce customers' costs. However, if the in-service date for one or more of these projects is delayed due to economic events or factors, or regulatory or other delays, the risk of failures in the electric transmission system may increase. We also implement new information technology systems from time to time, which may disrupt operations. Any failure of our transmission and distribution systems to operate as planned may result in increased capital costs, reduced earnings or unplanned increases in operations and maintenance costs. The inability to recover a significant amount of such costs could have an adverse effect on our financial position, results of operations and cash flows. New technology and alternative energy sources could adversely affect our operations and financial results. Advances in technology that reduce the costs of alternative methods of producing electric energy to a level that is competitive with that of current electric production methods, could result in loss of market share and customers, and may require us to make significant expenditures to remain competitive. These changes in technology, including micro-grids and advances in energy or battery storage, could also alter the channels through which electric customers buy or utilize energy, which could reduce our revenues or increase our expenses. Economic downturns or periods of high energy supply costs typically can lead to the development of legislative and regulatory policy designed to promote reductions in energy consumption and increased energy efficiency and self-generation by customers. Additionally, in response to risks posed by climate change, we may need to make investments in our system including upgrades or retrofits to meet enhanced design criteria, which can incur additional costs over conventional solutions. The loss of key personnel, the inability to hire and retain qualified employees, or the failure to maintain a positive relationship with our workforce could have an adverse effect on our business, financial position and results of operations. Our operations depend on the continued efforts of our employees. Retaining key employees and maintaining the ability to attract new employees are important to both our operational and financial performance. We cannot guarantee that any member of our management or any key employee at the Eversource parent or subsidiary level will continue to serve in any capacity for any particular period of time. Our workforce in our subsidiaries includes many workers with highly specialized skills maintaining and servicing the electric, natural gas and water infrastructure that cannot be quickly replaced due to the technically complex work they perform. We have developed strategic workforce plans to identify key functions and proactively implement plans to assure a ready and qualified workforce, but we cannot predict the impact of these plans on our ability to hire and retain key employees. Labor disputes, work stoppages or an inability to negotiate future collective bargaining agreements on commercially reasonable terms, as well as the increased competition for talent or the intentional misconduct of employees or contractors, may also have an adverse effect on our business, financial position and results of operations. Risks Related to the Environment and Catastrophic Events: The effects of climate change, including severe storms, could cause significant damage to any of our facilities requiring extensive expenditures, the recovery for which is subject to approval by regulators. Climate change creates physical and financial risks to our operations. Physical risks from climate change may include an increase in sea levels and changes in weather conditions, such as changes in precipitation, extreme heat and extreme weather events. Customers energy and water needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. For water customers, conservation measures imposed by the communities we serve could impact water usage. To the extent weather conditions are affected by climate change, customers energy and water usage could increase or decrease depending on the duration and magnitude of the changes. Severe weather, such as ice and snow storms, tornadoes, micro-bursts, hurricanes, floods, droughts, and other natural disasters, may cause outages and property damage, which may require us to incur additional costs that may not be recoverable from customers. The cost of repairing damage to our operating subsidiaries' facilities and the potential disruption of their operations due to storms, natural disasters or other catastrophic events could be substantial, particularly as regulators and customers demand better and quicker response times to outages. If, upon review, any of our state regulatory authorities finds that our actions were imprudent, some of those restoration costs may not be recoverable from customers, and could result in penalties or fines. The inability to recover a significant amount of such costs could have an adverse effect on our financial position, results of operations and cash flows. We maintain property insurance, but it may be insufficient in limits and coverage exclusions to cover all losses. Additionally, these types of weather events risk interruption of the supply chain and could disrupt the delivery of goods and services required for our operations. Transitional impacts related to climate change may have an adverse effect on our business and results of operations due to costs associated with new technologies, evolving customer expectations and changing workforce needs. Initiatives to mitigate the impacts of climate change, support a transition to cleaner energy, and reduce emissions, may have a material adverse financial impact to our business. These impacts include the costs associated with the development and implementation of new technologies to maintain system reliability and resiliency and lower emissions, including grid modernization and energy storage. An increase in such costs, unless promptly recovered, could have an adverse impact on our financial position, results of operations and cash flows. There may also be financial and reputational risks if we fail to meet evolving customer expectations, including enabling the integration of residential renewables and providing low carbon solutions, such as electric vehicle infrastructure and energy efficiency services. Additionally, actions to mitigate climate change may result in a transition in our workforce that must adapt to meet the need for new job skills. Associated costs include training programs for existing employees and workforce development as we transition to new technologies and clean energy solutions. Adequacy of water supplies and contamination of our water supplies, the failure of dams on reservoirs providing water to our customers, or requirements to repair, upgrade or dismantle any of these dams, may disrupt our ability to distribute water to our customers and result in substantial additional costs, which could adversely affect our financial position, results of operations and cash flows. Our water business faces an inherent strategic risk related to adequacy of supply (i.e., water scarcity). Water scarcity risk is heightened by multiple factors. We expect that climate change will cause both an increase in demand due to increasing temperatures and a potential for a decrease of available supply due to shifting rainfall and recharge patterns. Regulatory constraints also present challenges to permit new sources of supply in the region. In Connecticut, where the vast majority of our dams are located, impounded waterways are required to release minimum downstream flow. New regulations are being phased into effect over the next one to five years that will increase the volume of downstream releases required across our Connecticut service territory, depleting the volume of supply in storage that is used to meet customer demands. This combination of factors may cause an increased likelihood of drought emergencies and water use restrictions that could adversely affect our ability to provide water to our customers, and reputational/brand damage that could negatively impact our water business. Our water supplies, including water provided to our customers, are also subject to possible contamination from naturally occurring compounds or man-made substances. Our water systems include impounding dams and reservoirs of various sizes. Although we believe our dams are structurally sound and well-maintained, significant damage to these facilities, or a significant decrease in the water in our reservoirs, could adversely affect our ability to provide water to our customers until the facilities and a sufficient amount of water in our reservoirs can be restored. A failure of a dam could result in personal injuries and downstream property damage for which we may be liable. The failure of a dam would also adversely affect our ability to supply water in sufficient quantities to our customers. Any losses or liabilities incurred due to a failure of one of our dams may not be recoverable in rates and may have a material adverse effect on our financial position, results of operations and cash flows. We maintain liability insurance, but it may be insufficient in limits and coverage exclusions to cover all losses. Physical attacks, including acts of war or terrorism, both threatened and actual, could adversely affect our ability to operate our systems and could adversely affect our financial results and liquidity. Physical attacks, including acts of war or terrorism, both threatened and actual, that damage our transmission and distribution systems or other assets could negatively impact our ability to transmit or distribute energy, water, natural gas, or operate our systems efficiently or at all. Because our electric transmission systems are part of an interconnected regional grid, we face the risk of widespread blackouts due to grid disturbances or disruptions on a neighboring interconnected system. Similarly, our natural gas distribution system is connected to transmission pipelines not owned by Eversource. If there was an attack on the transmission pipelines, it could impact our ability to deliver natural gas. If our assets were physically damaged and were not recovered in a timely manner, it could result in a loss of service to customers, a significant decrease in revenues, significant expense to repair system damage, costs associated with governmental actions in response to such attacks, and liability claims, all of which could have a material adverse impact on our financial position, results of operations and cash flows. We maintain property and liability insurance, but it may be insufficient in limits and coverage exclusions to cover all losses. In addition, physical attacks against third-party providers could have a similar effect on the operation of our systems. Regulatory, Legislative and Compliance Risks: The actions of regulators and legislators could result in outcomes that may adversely affect our earnings and liquidity. The rates that our electric, natural gas and water companies charge their customers are determined by their state regulatory commissions and by the FERC. These commissions also regulate the companies' accounting, operations, the issuance of certain securities and certain other matters. The FERC also regulates the transmission of electric energy, the sale of electric energy at wholesale, accounting, issuance of certain securities and certain other matters, including reliability standards through the NERC. The regulatory process may be adversely affected by the political, regulatory and economic environment in the states in which we operate. Under state and federal law, our electric, natural gas and water companies are entitled to charge rates that are sufficient to allow them an opportunity to recover their prudently incurred operating and capital costs and a reasonable rate of return on invested capital, to attract needed capital and maintain their financial integrity, while also protecting relevant public interests. Our electric, natural gas and water companies are required to engage in regulatory approval proceedings as a part of the process of establishing the terms and rates for their respective services. Each of these companies prepares and submits periodic rate filings with their respective regulatory commissions for review and approval, which allows for various entities to challenge our current or future rates, structures or mechanisms and could alter or limit the rates we are allowed to charge our customers. These proceedings typically involve multiple parties, including governmental bodies and officials, consumer advocacy groups, and various consumers of energy, who have differing concerns. Any change in rates, including changes in allowed rate of return, are subject to regulatory approval proceedings that can be contentious, lengthy, and subject to appeal. This may lead to uncertainty as to the ultimate result of those proceedings. Established rates are also subject to subsequent prudency reviews by state regulators, whereby various portions of rates could be adjusted, subject to refund or disallowed, including cost recovery mechanisms. The ultimate outcome and timing of regulatory rate proceedings or challenges to certain provisions in our distribution tariffs could have a significant effect on our ability to recover costs or earn an adequate return. Adverse decisions in our proceedings could adversely affect our financial position, results of operations and cash flows. The federal, state and local political and economic environment has had, and may in the future have, an adverse effect on regulatory decisions with negative consequences for us. These decisions may require us to cancel, reduce, or delay planned development activities or other planned capital expenditures or investments or otherwise incur costs that we may not be able to recover through rates. There can be no assurance that regulators will approve the recovery of all costs incurred by our electric, natural gas and water companies, including costs for construction, operation and maintenance, and storm restoration. The inability to recover a significant amount of operating costs could have an adverse effect on our financial position, results of operations, and cash flows. Changes to rates may occur at times different from when costs are incurred. Additionally, catastrophic events at other utilities could result in our regulators and legislators imposing additional requirements that may lead to additional costs for the companies. In addition to the risk of disallowance of incurred costs, regulators may also impose downward adjustments in a companys allowed ROE as well as assess penalties and fines. These actions would have an adverse effect on our financial position, results of operations and cash flows. The FERC has jurisdiction over our transmission costs recovery and our allowed ROEs. If FERC changes their methodologies on developing ROEs there could be a negative impact on our results of operations and cash flows. Additionally, certain outside parties have filed four complaints against all electric companies under the jurisdiction of ISO-NE alleging that our allowed ROEs are unjust and unreasonable. An adverse decision in any of these four complaints could adversely affect our financial position, results of operations and cash flows. FERC's policy has encouraged competition for transmission projects, even within existing service territories of electric companies. Implementation of FERC's goals, including within our service territories, may expose us to competition for construction of transmission projects, additional regulatory considerations, and potential delay with respect to future transmission projects, which may adversely affect our results of operations and lower rate base growth. Changes in tax laws, including the Inflation Reduction Act (IRA) of 2022, as well as the potential tax effects of business decisions could negatively impact our business, results of operations (including our expected project returns from our planned offshore wind facilities), financial condition and cash flows. We are exposed to significant reputational risks, which make us vulnerable to increased regulatory oversight or other sanctions. Because utility companies, including our electric, natural gas and water utility subsidiaries, have large customer bases, they are subject to adverse publicity focused on the reliability of their distribution services and the speed with which they are able to respond to electric outages, natural gas leaks and similar interruptions caused by storm damage or other unanticipated events, including those related to climate change. Adverse publicity of this nature could harm our reputation and the reputation of our subsidiaries; may make state legislatures, utility commissions and other regulatory authorities less likely to view us in a favorable light; and may cause us to be subject to less favorable legislative and regulatory outcomes, legal claims or increased regulatory oversight. Unfavorable regulatory outcomes can include more stringent laws and regulations governing our operations, such as reliability and customer service quality standards or vegetation management requirements, as well as fines, penalties or other sanctions or requirements. Further, we rely upon purchased power and purchased natural gas supply from third parties to meet customers energy requirements. Due to a variety of factors, including the inflationary economic environment, conflict in Russia and Ukraine, and increased customer energy demand, the cost of energy supply in New England has significantly increased. We also may be required to implement roll ing blackouts by ISO-New England, the regions independent grid operator if enough capacity is not available in the area to meet peak demand needs. The significant supply cost increases, as well as any failure to meet customer energy requirements, could negatively impact the satisfaction of our customers and our customers ability to pay their utility bill, which could have an adverse impact on our business, reputation, financial position, results of operations and cash flows. Addressing any adverse publicity, regulatory scrutiny or enforcement or other legal proceedings is time consuming and expensive and, regardless of the factual basis for the assertions being made, can have a negative impact on the reputation of our business, on the morale and performance of our employees and on our relationships with respective regulators, customers and counterparties. We are unable to predict future legislative or regulatory changes, initiatives or interpretations, and there can be no assurance that we will be able to respond adequately or sufficiently quickly to such actions. The direct and indirect effects of negative publicity, and the demands of responding to and addressing it, may have a material adverse effect on our financial position, results of operations and cash flows. Costs of compliance with environmental laws and regulations, including those related to climate change, may increase and have an adverse effect on our business and results of operations. Our subsidiaries' operations are subject to extensive and increasing federal, state and local environmental statutes, rules and regulations that govern, among other things, water quality, water discharges, the management of hazardous material and solid waste, and air emissions. Compliance with these requirements requires us to incur significant costs relating to environmental permitting, monitoring, maintenance and upgrading of facilities, remediation, and reporting. The costs of compliance with existing legal requirements or legal requirements not yet adopted may increase in the future. Although we have recorded liabilities for known environmental obligations, these costs can be difficult to estimate due to uncertainties about the extent of contamination, remediation alternatives, the remediation levels required by state and federal agencies, and the financial ability of other potentially responsible parties. An increase in such costs, unless promptly recovered, could have an adverse impact on our business and our financial position, results of operations and cash flows. For further information, see Item 1, Business - Other Regulatory and Environmental Matters , included in this Annual Report on Form 10-K. Financial, Economic, and Market Risks: Limits on our access to, or increases in, the cost of capital may adversely impact our ability to execute our business plan. We use short-term debt and the long-term capital markets as a significant source of liquidity and funding for capital requirements not obtained from our operating cash flow. If access to these sources of liquidity becomes constrained, our ability to implement our business strategy could be adversely affected. In addition, interest rates have increased and may continue to increase in the future. As a result, interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly, which could adversely impact our financial position, results of operations and cash flows. A downgrade of our credit ratings or events beyond our control, such as a disruption in global capital and credit markets, could increase our cost of borrowing and cost of capital or restrict our ability to access the capital markets and negatively affect our ability to maintain and to expand our businesses. Market performance or changes in assumptions may require us to make significant contributions to our pension and other postretirement benefit plans. We provide a defined benefit pension plan and other postretirement benefits for a substantial number of employees, former employees and retirees. Our future pension obligations, costs and liabilities are highly dependent on a variety of factors, many of which are beyond our control. These factors include estimated investment returns, interest rates, discount rates, health care cost trends, benefit changes, salary increases and the demographics of plan participants. If our assumptions prove to be inaccurate, our future costs could increase significantly. In addition, various factors, including underperformance of plan investments and changes in law or regulation, could increase the amount of contributions required to fund our pension plan in the future. Additional large funding requirements, when combined with the financing requirements of our construction program, could impact the timing, amounts, and number of future financings and negatively affect our financial position, results of operations and cash flows. Our goodwill is recorded at an amount that, if impaired and written down, could adversely affect our future operating results and total capitalization. We have a significant amount of goodwill on our consolidated balance sheet, which, as of December 31, 2022, totaled $4.52 billion. The carrying value of goodwill represents the fair value of an acquired business in excess of the fair value of identifiable assets and liabilities as of the acquisition date. We test our goodwill balances for impairment on an annual basis or whenever events occur, or circumstances change that would indicate a potential for impairment. A determination that goodwill is deemed to be impaired would result in a non-cash charge that could materially adversely affect our financial position, results of operations and total capitalization. Our counterparties may not meet their obligations to us or may elect to exercise their termination rights, which could adversely affect our earnings. We are exposed to the risk that counterparties to various arrangements that owe us money, have contracted to supply us with energy or other commodities or services, or that work with us as strategic partners, including on significant capital projects, will not be able to perform their obligations, will terminate such arrangements or, with respect to our credit facilities, fail to honor their commitments. Should any of these counterparties fail to perform their obligations or terminate such arrangements, we might be forced to replace the underlying commitment at higher market prices and/or have to delay the completion of, or cancel, a capital project. Should any lenders under our credit facilities fail to perform, the level of borrowing capacity under those arrangements could decrease. In any such events, our financial position, results of operations, or cash flows could be adversely affected. As a holding company with no revenue-generating operations, Eversource parent's liquidity is dependent on dividends from its subsidiaries, its commercial paper program, and its ability to access the long-term debt and equity capital markets. Eversource parent is a holding company and as such, has no revenue-generating operations of its own. Its ability to meet its debt service obligations and to pay dividends on its common shares is largely dependent on the ability of its subsidiaries to pay dividends to, or repay borrowings from, Eversource parent, and/or Eversource parent's ability to access its commercial paper program or the long-term debt and equity capital markets. Prior to funding Eversource parent, the subsidiary companies have financial obligations that must be satisfied, including among others, their operating expenses, debt service, preferred dividends of certain subsidiaries, and obligations to trade creditors. Should the subsidiary companies not be able to pay dividends or repay funds due to Eversource parent, or if Eversource parent cannot access its commercial paper programs or the long-term debt and equity capital markets, Eversource parent's ability to pay interest, dividends and its own debt obligations would be restricted.

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##TABLE_START ITEM 1. ##TABLE_ENDGeneral Corporate Structure and Business and Other Information Exelon is a utility services holding company engaged in the energy distribution and transmission businesses through ComEd, PECO, BGE, Pepco, DPL, and ACE. On February 21, 2021, Exelons Board of Directors approved a plan to separate the Utility Registrants and Generation. The separation was completed on February 1, 2022, creating two publicly traded companies, Exelon and Constellation. See Note 2 Discontinued Operations of the Combined Notes to Consolidated Financial Statements for additional information. ##TABLE_START Name of Registrant Business Service Territories Commonwealth Edison Company Purchase and regulated retail sale of electricity Northern Illinois, including the City of Chicago Transmission and distribution of electricity to retail customers PECO Energy Company Purchase and regulated retail sale of electricity and natural gas Southeastern Pennsylvania, including the City of Philadelphia (electricity) Transmission and distribution of electricity and distribution of natural gas to retail customers Pennsylvania counties surrounding the City of Philadelphia (natural gas) Baltimore Gas and Electric Company Purchase and regulated retail sale of electricity and natural gas Central Maryland, including the City of Baltimore (electricity and natural gas) Transmission and distribution of electricity and distribution of natural gas to retail customers Pepco Holdings LLC Utility services holding company engaged, through its reportable segments: Pepco, DPL, and ACE Service Territories of Pepco, DPL, and ACE Potomac Electric Power Company Purchase and regulated retail sale of electricity District of Columbia and Major portions of Montgomery and Prince Georges Counties, Maryland Transmission and distribution of electricity to retail customers Delmarva Power Light Company Purchase and regulated retail sale of electricity and natural gas Portions of Delaware and Maryland (electricity) Transmission and distribution of electricity and distribution of natural gas to retail customers Portions of New Castle County, Delaware (natural gas) Atlantic City Electric Company Purchase and regulated retail sale of electricity Portions of Southern New Jersey Transmission and distribution of electricity to retail customers ##TABLE_ENDBusiness Services Through its business services subsidiary, BSC, Exelon provides its subsidiaries with a variety of support services at cost, including legal, human resources, financial, information technology, and supply management services. PHI also has a business services subsidiary, PHISCO, which provides a variety of support services at cost, including legal, finance, engineering, customer operations, distribution and transmission planning, asset management, system operations, and power procurement, to PHI operating companies. The costs of BSC and PHISCO are directly charged or allocated to the applicable subsidiaries. The results of Exelons corporate operations are presented as Other within the consolidated financial statements and include intercompany eliminations unless otherwise disclosed. Utility Registrants Utility Operations Service Territories and Franchise Agreements The following table presents the size of service territories, populations of each service territory, and the number of customers within each service territory for the Utility Registrants as of December 31, 2022: ##TABLE_START ComEd PECO BGE Pepco DPL ACE Service Territories (in square miles) Electric 11,450 1,900 2,300 650 5,400 2,750 Natural Gas N/A 1,900 3,050 N/A 250 N/A Total (a) 11,450 2,100 3,250 650 5,400 2,750 Service Territory Population (in millions) Electric 9.3 4.1 3.0 2.4 1.5 1.2 Natural Gas N/A 2.5 2.9 N/A 0.6 N/A Total (b) 9.3 4.1 3.2 2.4 1.5 1.2 Main City Chicago Philadelphia Baltimore District of Columbia Wilmington Atlantic City Main City Population 2.7 1.6 0.6 0.7 0.1 0.1 Number of Customers (in millions) Electric 4.1 1.7 1.3 0.9 0.5 0.6 Natural Gas N/A 0.5 0.7 N/A 0.1 N/A Total (c) 4.1 1.7 1.3 0.9 0.5 0.6 ##TABLE_END ____________ (a) The number of total service territory square miles counts once only a square mile that includes both electric and natural gas services, and thus does not represent the combined total square mileage of electric and natural gas service territories. (b) The total service territory population counts once only an individual who lives in a region that includes both electric and natural gas services, and thus does not represent the combined total population of electric and natural gas service territories. (c) The number of total customers counts once only a customer who is both an electric and a natural gas customer, and thus does not represent the combined total of electric customers and natural gas customers. The Utility Registrants have the necessary authorizations to perform their current business of providing regulated electric and natural gas distribution services in the various municipalities and territories in which they now supply such services. These authorizations include charters, franchises, permits, and certificates of public convenience issued by local and state governments and state utility commissions. ComEd's, BGE's (gas), Pepco DC's, and ACE's rights are generally non-exclusive while PECO's, BGE's (electric), Pepco MD's, and DPL's rights are generally exclusive. Certain authorizations are perpetual while others have varying expiration dates. The Utility Registrants anticipate working with the appropriate governmental bodies to extend or replace the authorizations prior to their expirations. Utility Regulations State utility commissions regulate the Utility Registrants' electric and gas distribution rates and service, issuances of certain securities, and certain other aspects of the business. The following table outlines the state commissions responsible for utility oversight: ##TABLE_START Registrant Commission ComEd ICC PECO PAPUC BGE MDPSC Pepco DCPSC/MDPSC DPL DEPSC/MDPSC ACE NJBPU ##TABLE_ENDThe Utility Registrants are public utilities under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of the utilities' business. The U.S. Department of Transportation also regulates pipeline safety and other areas of gas operations for PECO, BGE, and DPL. The U.S. Department of Homeland Security (Transportation Security Administration) provided new security directives in 2021 that regulate cyber risks for certain gas distribution operators. Additionally, the Utility Registrants are subject to NERC mandatory reliability standards, which protect the nation's bulk power system against potential disruptions from cyber and physical security breaches. Seasonality Impacts on Delivery Volumes The Utility Registrants' electric distribution volumes are generally higher during the summer and winter months when temperature extremes create demand for either summer cooling or winter heating. For PECO, BGE, and DPL, natural gas distribution volumes are generally higher during the winter months when cold temperatures create demand for winter heating. ComEd, BGE, Pepco, DPL Maryland, and ACE have electric distribution decoupling mechanisms and BGE has a natural gas decoupling mechanism that eliminate the favorable and unfavorable impacts of weather and customer usage patterns on electric distribution and natural gas delivery volumes. As a result, ComEd's, BGE's, Pepco's, DPL Maryland's, and ACE's electric distribution revenues and BGE's natural gas distribution revenues are not materially impacted by delivery volumes. PECO's and DPL Delaware's electric distribution revenues and natural gas distribution revenues are impacted by delivery volumes. Electric and Natural Gas Distribution Services The Utility Registrants are allowed to recover reasonable costs and fair and prudent capital expenditures associated with electric and natural gas distribution services and earn a return on those capital expenditures, subject to commission approval. ComEd recovers costs through a performance-based rate formula. ComEd is required to file an update to the performance-based rate formula on an annual basis. On September 15, 2021, Illinois passed CEJA, which contains requirements for ComEd to transition away from the performance-based rate formula by the end of 2022 and would allow for the submission of either a general rate or multi-year rate plan. On February 3, 2022, the ICC approved a tariff that establishes the process under which ComEd will reconcile its 2022 and 2023 rate year revenue requirements with actual costs. ComEd filed a petition with the ICC seeking approval of a multi-year rate plan (MRP) for 2024-2027 on January 17, 2023. PECO's and DPL's electric and gas distribution costs and ACE's electric distribution costs have generally been recovered through rate case proceedings, with PECO utilizing a fully projected future test year while DPL and ACE utilize a historical test year. BGEs electric and gas distribution costs and Pepcos and DPL Maryland's electric distribution costs are currently recovered through multi-year rate case proceedings, as the MDPSC and the DCPSC allow utilities to file multi-year rate plans. In certain instances, the Utility Registrants use specific recovery mechanisms as approved by their respective regulatory agencies. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information. ComEd, Pepco, DPL and ACE customers have the choice to purchase electricity, and PECO and BGE customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers. DPL customers, with the exception of certain commercial and industrial customers, do not have the choice to purchase natural gas from competitive natural gas suppliers. The Utility Registrants remain the distribution service providers for all customers and are obligated to deliver electricity and natural gas to customers in their respective service territories while charging a regulated rate for distribution service. In addition, the Utility Registrants also retain significant default service obligations to provide electricity to certain groups of customers in their respective service areas who do not choose a competitive electric generation supplier. PECO, BGE, and DPL also retain significant default service obligations to provide natural gas to certain groups of customers in their respective service areas who do not choose a competitive natural gas supplier. For customers that choose to purchase electric generation or natural gas from competitive suppliers, the Utility Registrants act as the billing agent and therefore do not record Operating revenues or Purchased power and fuel expense related to the electricity and/or natural gas. For customers that choose to purchase electric generation or natural gas from a Utility Registrant, the Utility Registrants are permitted to recover the electricity and natural gas procurement costs from customers without mark-up or with a slight mark-up and therefore record the amounts in Operating revenues and Purchased power and fuel expense. As a result, fluctuations in electricity or natural gas sales and procurement costs have no significant impact on the Utility Registrants Net income. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Results of Operations and Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding electric and natural gas distribution services. Procurement of Electricity and Natural Gas Exelon does not generate the electricity it delivers. The Utility Registrants' electric supply for its customers is primarily procured through contracts as directed by their respective state laws and regulatory commission actions. The Utility Registrants procure electricity supply from various approved bidders or from purchases on the PJM operated markets. PECO's, BGEs, and DPL's natural gas supplies are purchased from a number of suppliers for terms that currently do not exceed three years. PECO, BGE, and DPL each have annual firm transportation contracts of 443,000 mmcf, 268,000 mmcf, and 44,000 mmcf, respectively, for delivery of gas. To supplement gas transportation and supply at times of heavy winter demands and in the event of temporary emergencies, PECO, BGE, and DPL have available storage capacity from the following sources: ##TABLE_START Peak Natural Gas Sources (in mmcf) LNG Facility Propane-Air Plant Underground Storage Service Agreements (a) PECO 1,200 150 19,400 BGE 1,056 550 22,000 DPL 250 N/A 3,900 ##TABLE_END___________ (a) Natural gas from underground storage represents approximately 27%, 42%, and 33% of PECO's, BGEs, and DPL's 2022-2023 heating season planned supplies, respectively. PECO, BGE, and DPL have long-term interstate pipeline contracts and also participate in the interstate markets by releasing pipeline capacity or bundling pipeline capacity with gas for off-system sales. Off-system gas sales are low-margin direct sales of gas to wholesale suppliers of natural gas. Earnings from these activities are shared between the utilities and customers. PECO, BGE, and DPL make these sales as part of a program to balance its supply and cost of natural gas. The off-system gas sales are not material to PECO, BGE, and DPL. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK, Commodity Price Risk (All Registrants), for additional information regarding Utility Registrants' contracts to procure electric supply and natural gas. Energy Efficiency Programs The Utility Registrants are generally allowed to recover costs associated with the energy efficiency and demand response programs they offer. Each commission approved program seeks to meet mandated electric consumption reduction targets and implement demand response measures to reduce peak demand. The programs are designed to meet standards required by each respective regulatory agency. ComEd, with limited exceptions, earns a return on its energy efficiency costs through a regulatory asset. BGE, Pepco Maryland, DPL Maryland, and ACE earn a return on most of their energy efficiency and demand response program costs through a regulatory asset. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information. Capital Investment The Utility Registrants' businesses are capital intensive and require significant investments, primarily in electric transmission and distribution and natural gas transportation and distribution facilities, to ensure the adequate capacity, reliability, and efficiency of their systems. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Liquidity and Capital Resources, for additional information regarding projected 2023 capital expenditures. Transmission Services Under FERCs open access transmission policy, the Utility Registrants, as owners of transmission facilities, are required to provide open access to their transmission facilities under filed tariffs at cost-based rates approved by FERC. The Utility Registrants and their affiliates are required to comply with FERCs Standards of Conduct regulation governing the communication of non-public transmission information between the transmission owners employees and wholesale merchant employees. PJM is the regional grid operator and operates pursuant to FERC-approved tariffs. PJM is the transmission provider under, and the administrator of, the PJM Tariff. PJM operates the PJM energy, capacity, and other markets, and, through central dispatch, controls the day-to-day operations of the bulk power system for the region. The Utility Registrants are members of PJM and provide regional transmission service pursuant to the PJM Tariff. The Utility Registrants and the other transmission owners in PJM have turned over control of certain of their transmission facilities to PJM, and their transmission systems are under the dispatch control of PJM. Under the PJM Tariff, transmission service is provided on a region-wide, open-access basis using the transmission facilities of the PJM transmission owners. The Utility Registrants' transmission rates are established based on a FERC approved formula as shown below: ##TABLE_START Approval Date ComEd January 2008 PECO December 2019 BGE April 2006 Pepco April 2006 DPL April 2006 ACE April 2006 ##TABLE_ENDExelons Strategy and Outlook Following the separation on February 1, 2022, Exelon is now a Distribution and Transmission company, focused on delivering electricity and natural gas service to our customers and communities. Exelon's businesses remain focused on maintaining industry leading operational excellence, meeting or exceeding their financial commitments, ensuring timely recovery on investments to enable customer benefits, supporting clean energy policies including those that advance our jurisdictions' clean energy targets, and continued commitment to corporate responsibility. Exelons strategy is to improve reliability and operations, enhance the customer experience, and advance clean and affordable energy choices, while ensuring ratemaking mechanisms provide the utilities fair financial returns. The jurisdictions in which Exelon has operations have set some of the nation's leading clean energy targets and our strategy is to enable that future for all our stakeholders. The Utility Registrants invest in rate base that supports service to our customers and the community, including investments that sustain and improve reliability and resiliency and that enhance the service experience of our customers. The Utility Registrants make these investments prudently at a reasonable cost to customers. Exelon seeks to leverage its scale and expertise across the utilities platform through enhanced standardization and sharing of resources and best practices to achieve improved operational and financial results. Management continually evaluates growth opportunities aligned with Exelons businesses, assets, and markets, leveraging Exelons expertise in those areas and offering sustainable returns. The Utility Registrants anticipate investing approximately $31 billion over the next four years in electric and natural gas infrastructure improvements and modernization projects, including smart grid technology, storm hardening, advanced reliability technologies, and transmission projects, which is projected to result in an increase to current rate base of approximately $18 billion by the end of 2026. These investments provide greater reliability, improved service for our customers, increased capacity to accommodate new technologies and support a cleaner grid, and a stable return for the company. In August 2021, Exelon announced a Path to Clean goal to collectively reduce its operations-driven GHG emissions 50% by 2030 against a 2015 baseline and to reach net zero operations-driven GHG emissions by 2050, while supporting customers and communities in achieving their GHG reduction goals (Path to Clean). Exelon's quantitative goals include its Scope 1 and 2 GHG emissions, with the exception of Scope 2 emissions associated with system losses of electric power delivered to customers ("line losses"), and build upon Exelon's long-standing commitment to reducing our GHG emissions. Exelon's Path to Clean efforts extend beyond these quantitative goals to include efforts such as customer energy efficiency programs, which support reductions in customers' direct emissions and have the potential to reduce Exelon's Scope 3 emissions and Scope 2 line losses as well. See ITEM 1. BUSINESS Environmental Matters and Regulation Climate Change for additional information. Various market, financial, regulatory, legislative, and operational factors could affect Exelon's success in pursuing its strategies. Exelon continues to assess infrastructure, operational, policy, and legal solutions to these issues. See ITEM 1A. RISK FACTORS for additional information. Employees The Registrants strive to create a workplace culture that promotes and embodies diversity, inclusion, innovation, and safety for their employees. In order to provide the services and products that their customers expect, the Registrants aspire to create teams that reflect the diversity of the communities that the Registrants serve. Therefore, the Registrants take steps to attract highly qualified and diverse talent and seek to create hiring and promotion practices that are equitable and neutralize any bias, including unconscious bias. The Registrants provide growth opportunities, competitive compensation and benefits, and a variety of training and development programs. The Registrants are committed to helping employees grow their skills and careers largely through numerous training opportunities; mentorship programs; continuous feedback and development discussions; and evaluations. Employees are encouraged to thrive outside the workplace as well. The Registrants provide a full suite of wellness benefits targeted at supporting work-life balance, physical, mental and financial health, and industry-leading paid leave policies. The Registrants typically conduct an employee engagement survey every other year to help identify organizational strengths and areas of opportunity for growth. The survey results are reviewed with senior management and the Exelon Board of Directors. Diversity Metrics The following tables show diversity metrics for all employees and management as of December 31, 2022. ##TABLE_START Employees Exelon ComEd PECO BGE PHI Pepco DPL ACE Female (a)(b)(c) 5,300 1,535 752 786 1,270 329 139 109 People of Color (b)(c) 7,519 2,575 990 1,170 1,803 865 203 145 Aged 30 2,026 721 361 286 424 169 85 61 Aged 30-50 10,548 3,728 1,455 1,819 2,271 739 465 357 Aged 50 6,489 1,907 1,070 1,061 1,466 442 341 203 Total Employees (d) 19,063 6,356 2,886 3,166 4,161 1,350 891 621 ##TABLE_END##TABLE_START Management (e) Exelon ComEd PECO BGE PHI Pepco DPL ACE Female (a)(b)(c) 961 235 139 122 206 51 13 21 People of Color (b)(c) 1,086 331 134 166 276 116 32 22 Aged 30 29 7 9 4 6 2 2 Aged 30-50 1,715 510 182 265 395 120 58 40 Aged 50 1,286 363 190 163 276 61 57 40 Within 10 years of retirement eligibility 1,787 520 238 226 379 91 68 55 Total

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Employees in Management (d) 3,030 880 381 432 677 181 117 82 ##TABLE_END__________ (a) The Registrants have a particular focus on creating an environment that attracts and retains women by enabling them to stay in the workforce, grow with the company, and move up the ranks. (b) To effectuate Exelon's pay equity goals, Exelon conducts analysis on gender and racial pay equity. (c) Information concerning women and people of color is based on self-disclosed information. (d) Total employees represents the sum of the aged categories. (e) Management is defined as executive/senior level officials and managers as well as all employees who have direct reports and/or supervisory responsibilities. Turnover Rates As turnover is inherent, management succession planning is performed and tracked for all executives and critical key manager positions. Management frequently reviews succession planning to ensure the Registrants are prepared when positions become available. The table below shows the average turnover rate for all employees for the last three years of 2020 to 2022. ##TABLE_START Exelon ComEd PECO BGE PHI Pepco DPL ACE Retirement Age 3.71 % 4.09 % 4.10 % 3.48 % 3.79 % 3.74 % 4.42 % 3.88 % Voluntary 2.79 % 2.22 % 2.71 % 1.76 % 2.52 % 2.81 % 1.46 % 1.84 % Non-Voluntary 0.81 % 0.60 % 1.10 % 1.06 % 1.02 % 1.95 % 0.47 % 0.68 % ##TABLE_ENDCollective Bargaining Agreements Approximately 44% of Exelons employees participate in CBAs. The following table presents employee information, including information about CBAs, as of December 31, 2022. ##TABLE_START Total Employees Covered by CBAs Number of CBAs CBAs New and Renewed in 2022 (a) Total Employees Under CBAs New and Renewed in 2022 Exelon 8,379 10 2 906 ComEd 3,477 2 PECO 1,368 2 BGE 1,414 1 PHI 2,113 5 2 906 Pepco 890 1 1 890 DPL 621 2 ACE 401 2 1 16 ##TABLE_END__________ (a) Does not include CBAs that were extended in 2022 while negotiations are ongoing for renewal. Environmental Matters and Regulation The Registrants are subject to comprehensive and complex environmental legislation and regulation at the federal, state, and local levels, including requirements relating to climate change, air and water quality, solid and hazardous waste, and impacts on species and habitats. The Exelon Board of Directors is responsible for overseeing the management of environmental matters. Exelon has a management team to address environmental compliance and strategy, including the CEO; the Senior Vice President and Chief Strategy and Sustainability Officer; as well as senior management of the Utility Registrants. Performance of those individuals directly involved in environmental compliance and strategy is reviewed and affects compensation as part of the annual individual performance review process. The Audit and Risk Committee oversees compliance with environmental laws and regulations, including environmental risks related to Exelon's operations and facilities, as well as SEC disclosures related to environmental matters. Exelon's Corporate Governance Committee has the authority to oversee Exelons climate change and sustainability policies and programs, as discussed in further detail below. The respective Boards of the Utility Registrants oversee environmental issues related to these companies. The Exelon Board of Directors has general oversight responsibilities for ESG matters, including strategies and efforts to protect and improve the quality of the environment. Climate Change As detailed below, the Registrants face climate change mitigation and transition risks as well as adaptation risks. Mitigation and transition risks include changes to the energy systems as a result of new technologies, changing customer expectations and/or voluntary GHG goals, as well as local, state or federal regulatory requirements intended to reduce GHG emissions. Adaptation risk refers to risks to the Registrants' facilities or operations that may result from changes to the physical climate and environment, such as changes to temperature, weather patterns and sea level. Climate Change Mitigation and Transition The Registrants support comprehensive federal climate legislation that addresses the urgent need to substantially reduce national GHG emissions while providing appropriate protections for consumers, businesses, and the economy. In the absence of comprehensive federal climate legislation, Exelon supports the EPA moving forward with meaningful regulation of GHG emissions under the Clean Air Act. The Registrants currently are subject to, and may become subject to additional, federal and/or state legislation and/or regulations addressing GHG emissions. GHG emission sources associated with the Registrants include sulfur hexafluoride (SF6) leakage from electric transmission and distribution operations, refrigerant leakage from chilling and cooling equipment, and fossil fuel combustion in motor vehicles. In addition, PECO, BGE, and DPL, as distributors of natural gas are regulated with respect to reporting of natural gas (methane) leakage on the natural gas systems and consumer use of such natural gas. Since its inception, Exelon has positioned itself as a leader in climate change mitigation. Exelon uses definitions and protocols provided by the World Resources Institute for its GHG inventory. In 2021, Exelon's Scope 1 and 2 GHG emissions, as revised following its separation from Constellation, were just over 5.7 million metric tons carbon dioxide equivalent using the World Resources Institute Corporate Standard Market-based accounting. Of these emissions, 0.5 million metric tons are considered to be operations-driven and in more direct control of our employees and processes. The majority of these operations-driven emissions are fugitive emissions from the gas delivery systems of Registrants PECO, BGE, and DPL. The remaining 5.2 million metric tons, approximately 91%, are the indirect emissions associated with the operation and use of the electric distribution and transmission system and primarily consists of losses resulting from the Utility Registrant's delivery of electricity to their customers (line losses). These emissions are driven primarily by customer demand for electricity and the mix of generation assets supplying energy to the electric grid. The Registrants do not own generation and must comply with applicable legal and regulatory requirements governing procurement of electricity for delivery to retail customers and use of the system to support other transmission transactions. However, the Registrants do engage in efforts that help to reduce these emissions, including customer programs to drive customer energy efficiency, help to manage peak demands, and enable distributed solar generation. In August 2021, Exelon announced a Path to Clean goal to collectively reduce their operations-driven GHG emissions 50% by 2030 against a 2015 baseline, and to reach net zero operations-driven GHG emissions by 2050, while also supporting customers and communities to achieve their clean energy and emissions goals. Exelons quantitative goals include its Scope 1 and 2 GHG emissions, with the exception of Scope 2 line losses, and builds upon Exelon's long-standing commitment to reducing our GHG emissions. Exelon's activities in support of the Path to Clean goal will include efficiency and clean electricity for operations, vehicle fleet electrification, equipment and processes to reduce sulfur hexafluoride (SF6) leakage, investments in natural gas infrastructure to minimize methane leaks and increase safety and reliability, and investment and collaboration to develop new technologies. Beyond 2030, Exelon recognizes that technology advancement and continued policy support will be needed to ensure achievement of Net-Zero by 2050. Exelon is laying the groundwork by partnering with national labs, universities and research consortia to research, develop, and pilot clean technologies that will be needed, as well as working with our states, jurisdictions and policy makers to understand the scope and scale of energy transformation, and needed policies and incentives, that will be needed to reach local ambitions for GHG emissions reductions. The Utility Registrants are also supporting customers and communities to achieve their clean energy and emissions goals through significant energy efficiency programs. During 2023 - 2026, estimated customer program energy efficiency investments across the Utility Registrants total $3.5 billion. These programs enable customer savings through home energy audits, lighting discounts, appliance recycling, home improvement rebates, equipment upgrade incentives and innovative programs like smart thermostats and combined heat and power programs. As an energy delivery company, Exelon can play a key role in lowering GHG emissions across much of the economy in its service territories. In connecting end users of energy to electric and gas supply, Exelon can leverage its assets and customer interface to encourage efficient use of lower emitting resources as they become available. Electrification, where feasible for transportation, buildings, and industry coupled with simultaneous decarbonization of electric generation, can be a key lever for emissions reductions. To support this transition, Exelon is advocating for public policy supportive of vehicle electrification, investing in enabling infrastructure and technology, and supporting customer education and adoption. In addition, the Utility Registrants have a goal to electrify 30% of their own vehicle fleet by 2025, increasing to 50% by 2030. Clean fuels and other emerging technologies can also support the transition, lessen the strain on electric system expansion, and support energy system resiliency. Exelon, and its registrants PECO, BGE, and DPL that own gas distribution assets, are also continuing to explore these other decarbonization opportunities, supporting pilots of emerging energy technologies and clean fuels to support both operational and customer-driven emissions reductions. The energy transition may present challenges for the Utility Registrants and their service territories. Exelon believes its market and business model could be significantly affected by the transition of the energy system, such as through an increased electric load and decreased demand for natural gas, potentially accompanied by changes in technology, customer expectations, and/or regulatory structures. See ITEM 1A. RISK FACTORS. The Registrants are potentially affected by emerging technologies that could over time affect or transform the energy industry. Climate Change Adaptation The Registrants' facilities and operations are subject to the impacts of global climate change. Long-term shifts in climactic patterns, such as sustained higher temperatures and sea level rise, may present challenges for the Registrants and their service territories. Exelon believes its operations could be significantly affected by the physical risks of climate change. See ITEM 1A. RISK FACTORS for additional information related to the Registrants' risks associated with climate change. The Registrants' assets undergo seasonal readiness efforts to ensure they are ready for the weather projections of the summer and winter months. The Registrants consider and review national climate assessments to inform their planning. Each of the Utility Registrants also has well established system recovery plans and is investing in its systems to install advanced equipment and reinforce the local electric system, making it more weather resistant and less vulnerable to anticipated storm damage. International Climate Change Agreements. At the international level, the United States is a party to the United Nations Framework Convention on Climate Change (UNFCCC). The Parties to the UNFCCC adopted the Paris Agreement at the 21st session of the UNFCCC Conference of the Parties (COP 21) on December 12, 2015. Under the Agreement, which became effective on November 4, 2016, the parties committed to try to limit the global average temperature increase and to develop national GHG reduction commitments. On November 4, 2020, the United States formally withdrew from the Paris Agreement, but on January 20, 2021, President Biden accepted the Agreement, which resulted in the United States formal re-entry on February 19, 2021. The United States has set an economy-wide target of reducing its net GHG emissions by 50-52% below 2005 levels by 2030. On November 11, 2022 at the UNFCCC Conference of the Parties (COP 27), President Biden recommitted the U.S. to these goals and detailed the significant domestic climate actions the U.S. had taken to spur a new era of clean American manufacturing, enhance energy security, and drive down the costs of clean energy for consumers in the U.S. and around the world. Federal Climate Change Legislation and Regulation. On August 16, 2022, President Biden signed the Inflation Reduction Act (IRA), which aims to reduce U.S. carbon emissions and promote economic development through investments in clean and renewable energy projects. The consumer-facing clean energy tax credits created or expanded by the IRA are intended to drive rapid adoption of energy efficiency, electric transportation, and solar energy which would require Exelon's utilities to expand and modernize infrastructure, systems and services to integrate and optimize these resources. Regulation of GHGs from Power Plants under the Clean Air Act. The EPAs 2015 Clean Power Plan (CPP) established regulations addressing carbon dioxide emissions from existing fossil-fired power plants under Clean Air Act Section 111(d). The CPPs carbon pollution limits could be met through changes to the electric generation system, including shifting generation from higher-emitting units to lower- or zero-emitting units, as well as the development of new or expanded zero-emissions generation. In July 2019, the EPA published its final Affordable Clean Energy rule, which repealed the CPP and replaced it with less stringent emissions guidelines for existing fossil-fired power plants based on heat rate improvement measures that could be achieved within the fence line of individual plants. Exelon, together with a coalition of other electric utilities, filed a lawsuit in the U.S. Court of Appeals for the D.C. Circuit, challenging the rescission of the Clean Power Plan and enactment of the Affordable Clean Energy rule as unlawful. On January 19, 2021, the D.C. Circuit held the Affordable Clean Energy Rule (including its rescission of the Clean Power Plan) to be unlawful, vacated the rule, and remanded it to the EPA. The Supreme Court granted certiorari to examine the extent of the EPA's authority to regulate GHGs from power plants and, on June 30, 2022, reversed and remanded the D.C. Circuit's decision. The Supreme Court ruled that the EPA's use of generation shifting for development of standards in the Clean Power Plan went beyond Congress' intended authority under the Clean Air Act. The EPA has indicated that it will promulgate new GHG limits for existing power plants. Increased regulation of GHG emissions from power plants could increase the cost of electricity delivered or sold by the Registrants. As of February 1, 2022, following its separation from Constellation, Exelon no longer owns electric generation plants. State Climate Change Legislation and Regulation. A number of states in which the Registrants operate have state and regional programs to reduce GHG emissions and renewable and other portfolio standards, which impact the power sector. See discussion below for additional information on renewable and other portfolio standards. Certain northeast and mid-Atlantic states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, Virginia) currently participate in the RGGI. The program requires most fossil fuel-fired power plant owners and operators in the region to hold allowances, purchased at auction, for each ton of CO_2 emissions. Non-emitting resources do not have to purchase or hold these allowances. Pennsylvania joined RGGI in April 2022. Broader state programs impact other sectors as well, such as the District of Columbia's Clean Energy DC Omnibus Act and cross-sector GHG reduction plans, which resulted in recent requirements for Pepco to develop 5-year and 30-year decarbonization programs and strategies. Maryland expects to meet and exceed the mandate set in the Greenhouse Gas Emissions Reduction Act to reduce statewide GHG emissions 40% (from 2006 levels) by 2030, and the states Climate Solutions Now Act of 2022 further updates requirements with a proposal to reduce emissions 60% (from 2006 levels) by 2031. New Jersey accelerated its goals through Executive Order 274, which establishes an interim goal of 50% reductions below 2006 levels by 2030 and affirms its goal of achieving 80% reductions by 2050 and includes programs to drive greater amounts of electrified transportation. Illinois climate bill, CEJA, establishes decarbonization requirements for the state to transition to 100% clean energy by 2050 and supports programs to improve energy efficiency, manage energy demand, attract clean energy investment and accelerate job creation. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on CEJA. The Registrants cannot predict the nature of future regulations or how such regulations might impact future financial statements. Renewable and Clean Energy Standards. Each of the states where Exelon operates have adopted some form of renewable or clean energy procurement requirement. These standards impose varying levels of mandates for procurement of renewable or clean electricity (the definition of which varies by state) and/or energy efficiency. These are generally expressed as a percentage of annual electric load, often increasing by year. The Utility Registrants comply with these various requirements through acquiring sufficient bundled or unbundled credits such as RECs, CMCs, or ZECs, or paying an alternative compliance payment, and/or a combination of these compliance alternatives. The Utility Registrants are permitted to recover from retail customers the costs of complying with their state RPS requirements, including the procurement of RECs or other alternative energy resources. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information. Other Environmental Regulation Water Quality Under the federal Clean Water Act, NPDES permits for discharges into waterways are required to be obtained from the EPA or from the state environmental agency to which the permit program has been delegated, and permits must be renewed periodically. Certain of Exelon's facilities discharge water into waterways and are therefore subject to these regulations and operate under NPDES permits. Under Clean Water Act Section 404 and state laws and regulations, the Registrants may be required to obtain permits for projects involving dredge or fill activities in waters of the United States. Where Registrants facilities are required to secure a federal license or permit for activities that may result in a discharge to covered waters, they may be required to obtain a state water quality certification under Clean Water Act section 401. Solid and Hazardous Waste and Environmental Remediation CERCLA provides for response and removal actions coordinated by the EPA in the event of threatened releases of hazardous substances and authorizes the EPA either to clean up sites at which hazardous substances have created actual or potential environmental hazards or to order persons responsible for the situation to do so. Under CERCLA, generators and transporters of hazardous substances, as well as past and present owners and operators of hazardous waste sites, are strictly, jointly and severally liable for the cleanup costs of hazardous waste at sites, many of which are listed by the EPA on the National Priorities List (NPL). These PRPs can be ordered to perform a cleanup, can be sued for costs associated with an EPA-directed cleanup, may voluntarily settle with the EPA concerning their liability for cleanup costs, or may voluntarily begin a site investigation and site remediation under state oversight. Most states have also enacted statutes that contain provisions substantially similar to CERCLA. Such statutes apply in many states where the Registrants currently own or operate, or previously owned or operated, facilities, including Delaware, Illinois, Maryland, New Jersey, and Pennsylvania and the District of Columbia. In addition, RCRA governs treatment, storage and disposal of solid and hazardous wastes and cleanup of sites where such activities were conducted. The Registrants operations have in the past, and may in the future, require substantial expenditures in order to comply with these Federal and state environmental laws. Under these laws, the Registrants may be liable for the costs of remediating environmental contamination of property now or formerly owned by them and of property contaminated by hazardous substances generated by them. The Registrants own or lease a number of real estate parcels, including parcels on which their operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. The Registrants and their subsidiaries are, or could become in the future, parties to proceedings initiated by the EPA, state agencies, and/or other responsible parties under CERCLA and RCRA or similar state laws with respect to a number of sites or may undertake to investigate and remediate sites for which they may be subject to enforcement actions by an agency or third-party. ComEds and PECOs environmental liabilities primarily arise from contamination at former MGP sites, which were operated by ComEd's and PECO's predecessor companies. ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, have an on-going process to recover certain environmental remediation costs of the MGP sites through a provision within customer rates. BGE, Pepco, DPL, and ACE do not have material contingent liabilities relating to MGP sites. The amount to be expended in 2023 for compliance with environmental remediation related to contamination at former MGP sites and other gas purification sites is estimated to be approxim ately $52 million which consists primarily of $44 million at ComEd. As of December 31, 2022, the Registrants have established appropriate contingent liabilities for environmental remediation requirements. In addition, the Registrants may be required to make significant additional expenditures not presently determinable for other environmental remediation costs. See Note 3 Regulatory Matters and Note 18 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants environmental matters, remediation efforts, and related impacts to the Registrants Consolidated Financial Statements. Information about our Executive Officers as of February 14, 2023 Exelon ##TABLE_START Name Age Position Period Butler, Calvin G. Jr. 53 President and Chief Executive Officer, Exelon 2022 - Present Chief Operating Officer, Exelon 2021 - 2022 Senior Executive Vice President, Exelon 2019 - 2022 Chief Executive Officer, Exelon Utilities 2019 - 2022 Chief Executive Officer, BGE 2014 - 2019 Jones, Jeanne 43 Executive Vice President and Chief Financial Officer, Exelon 2022 - Present Senior Vice President, Corporate Finance, Exelon 2021 - 2022 Senior Vice President and Chief Financial Officer, ComEd 2018 - 2021 Glockner, David 62 Executive Vice President, Compliance, Audit and Risk, Exelon 2020 - Present Chief Compliance Officer, Citadel LLC 2017 - 2020 Littleton, Gayle E. 50 Executive Vice President, General Counsel, Exelon 2020 - Present Partner, Jenner Block LLP 2015 - 2020 Quiniones, Gil 56 Chief Executive Officer, ComEd 2021 - Present President and Chief Executive Officer, New York Power Authority 2011 - 2021 Innocenzo, Michael A. 57 President and Chief Executive Officer, PECO 2018 - Present Khouzami, Carim V. 48 President, BGE 2021 - Present Chief Executive Officer, BGE 2019 - Present Senior Vice President COO, Exelon Utilities 2018 - 2019 Anthony, J.

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Tyler 58 President and Chief Executive Officer, PHI, Pepco, DPL, and ACE 2021 - Present Senior Vice President and Chief Operating Officer, PHI, Pepco, DPL, and ACE 2016 - 2021 Trpik, Joseph R. 53 Senior Vice President and Corporate Controller, Exelon 2022 - Present Interim Senior Vice President CFO, ComEd 2021 - 2022 Senior Vice President CFO, Exelon Utilities 2018 - 2021 ##TABLE_END##TABLE_START ##TABLE_ENDComEd ##TABLE_START Name Age Position Period Quiniones, Gil 56 Chief Executive Officer, ComEd 2021 - Present President and Chief Executive Officer, New York Power Authority 2011 - 2021 Donnelly, Terence R. 62 President and Chief Operating Officer, ComEd 2018 - Present Graham, Elisabeth J. 44 Senior Vice President, Chief Financial Officer Treasurer, ComEd 2022 - Present Treasurer, Exelon 2018 - 2022 Rippie, E. Glenn 62 Senior Vice President and General Counsel, ComEd 2022 - Present Senior Vice President and Deputy General Counsel, Energy Regulation, Exelon 2022 - Present Partner, Jenner Block LLP 2019 - 2021 Partner and Chief Financial Officer, Rooney, Rippie Ratnaswamy, LLP 2010 - 2019 Washington, Melissa 53 Senior Vice President, Customer Operations, ComEd 2021 - Present Senior Vice President, Governmental and External Affairs, ComEd 2019 - 2021 Vice President, Governmental and External Affairs, ComEd 2019 - 2019 Vice President, External Affairs and Large Customer Services, ComEd 2016 - 2019 Binswanger, Lewis 63 Senior Vice President, Governmental, Regulatory and External Affairs, ComEd 2022 - Present Vice President, External Affairs, Nicor Gas 2013 - 2022 ##TABLE_ENDPECO ##TABLE_START Name Age Position Period Innocenzo, Michael A. 57 President and Chief Executive Officer, PECO 2018 - Present Levine, Nicole 46 Senior Vice President and Chief Operations Officer, PECO 2022 - Present Vice President, Electrical Operations, PECO 2018 - 2022 Humphrey, Marissa 43 Senior Vice President, Chief Financial Officer and Treasurer, PECO 2022 - Present Vice President, Regulatory Policy and Strategy (NJ/DE), PHI, DPL, and ACE 2021 - 2022 Vice President, Finance, Exelon Utilities 2019 - 2020 Vice President, Financial Planning and Analysis, PHI, Pepco, DPL, and ACE 2016 - 2019 Murphy, Elizabeth A. 63 Senior Vice President, Governmental, Regulatory and External Affairs, PECO 2016 - Present Williamson, Olufunmilayo 44 Senior Vice President, Customer Operations, PECO 2021 - Present Senior Vice President, Chief Commercial Risk Officer, Exelon 2017 - 2020 Gay, Anthony 57 Vice President and General Counsel, PECO 2019 - Present Vice President, Governmental and External Affairs, PECO 2016 - 2019 ##TABLE_ENDBGE ##TABLE_START Name Age Position Period Khouzami, Carim V. 48 President, BGE 2021 - Present Chief Executive Officer, BGE 2019 - Present Senior Vice President COO, Exelon Utilities 2018 - 2019 Dickens, Derrick 58 Senior Vice President and Chief Operating Officer, BGE 2021 - Present Senior Vice President, Customer Operations, PHI, Pepco, DPL, and ACE 2020 - 2021 Vice President, Technical Services, BGE 2016 - 2020 Vahos, David M. 50 Senior Vice President, Chief Financial Officer and Treasurer, BGE 2016 - Present Nez, Alexander G. 51 Senior Vice President, Governmental, Regulatory and External Affairs, BGE 2021 - Present Senior Vice President, Regulatory Affairs and Strategy, BGE 2020 - 2021 Senior Vice President, Regulatory and External

Affairs, BGE 2016 - 2020 Galambos, Denise 60 Senior Vice President, Customer Operations, BGE 2021 - Present Vice President, Utility Oversight, Exelon Utilities 2020 - 2021 Vice President, Human Resources, BGE 2018 - 2020 Ralph, David 56 Vice President and General Counsel, BGE 2021 - Present Associate General Counsel, BGE 2019 - 2021 Assistant General Counsel, Exelon 2017 - 2019 ##TABLE_ENDPHI, Pepco, DPL, and ACE ##TABLE_START Name Age Position Period Anthony, J. Tyler 58 President and Chief Executive Officer, PHI, Pepco, DPL, and ACE 2021 - Present Senior Vice President and Chief Operating Officer, PHI, Pepco, DPL, and ACE 2016 - 2021 Olivier, Tamla 50 Senior Vice President and Chief Operating Officer, PHI, Pepco, DPL, and ACE 2021 - Present Senior Vice President, Customer Operations, BGE 2020 - 2021 Senior Vice President, Constellation NewEnergy, Inc. 2016 - 2020 Barnett, Phillip S. 59 Senior Vice President, Chief Financial Officer and Treasurer, PHI, Pepco, DPL, and ACE 2018 - Present Oddoye, Rodney 46 Senior Vice President, Governmental, Regulatory and External Affairs, PHI, Pepco, DPL, and ACE 2021 - Present Senior Vice President, Governmental and External Affairs, BGE 2020 - 2021 Vice President, Customer Operations, BGE 2018 - 2020 Bancroft, Anne 56 Vice President and General Counsel, PHI, Pepco, DPL, and ACE 2021 - Present Associate General Counsel, Exelon 2017 - 2021 Bell-Izzard, Morlon 57 Senior Vice President, Customer Operations, PHI, Pepco, DPL, and ACE 2021 - Present Vice President, Customer Operations, PHI, Pepco, DPL, and ACE 2019 - 2021 Director, Utility Performance Assessment, Exelon 2016 - 2019 ##TABLE_END ITEM 1A. RISK FACTORS ##TABLE_ENDEach of the Registrants operates in a complex market and regulatory environment that involves significant risks, many of which are beyond that Registrants direct control. Such risks, which could negatively affect one or more of the Registrants consolidated financial statements, fall primarily under the categories below: Risks related to market and financial factors primarily include: the demand for electricity, reliability of service, and affordability in the markets where the Utility Registrants conduct their business, the ability of the Utility Registrants to operate their respective transmission and distribution assets, their ability to access capital markets, and the impacts on their results of operations, financial condition or liquidity/cash flows due to public health crises, epidemics or pandemics, such as COVID-19, and emerging technologies and business models, including those related to climate change mitigation and transition to a low carbon economy. Risks related to legislative, regulatory, and legal factors primarily include changes to, and compliance with, the laws and regulations that govern: utility regulatory business models, environmental and climate policy, and tax policy. Risks related to operational factors primarily include: changes in the global climate could produce extreme weather events, which could put the Registrants facilities at risk, and such changes could also affect the levels and patterns of demand for energy and related services, the ability of the Utility Registrants to maintain the reliability, resiliency, and safety of their energy delivery systems, which could affect their ability to deliver energy to their customers and affect their operating costs, and physical and cyber security risks for the Utility Registrants as the owner-operators of transmission and distribution facilities. Risks related to the separation primarily include: challenges to achieving the benefits of separation and performance by Exelon and Constellation under the transaction agreements, including indemnification responsibilities. There may be further risks and uncertainties that are not presently known or that are not currently believed to be material that could negatively affect the Registrants' consolidated financial statements in the future. Risks Related to Market and Financial Factors The Registrants are potentially affected by emerging technologies that could over time affect or transform the energy industry (All Registrants). Advancements in power generation technology, including commercial and residential solar generation installations and commercial micro turbine installations, are improving the cost-effectiveness of customer self-supply of electricity. Improvements in energy storage technology, including batteries and fuel cells, could also better position customers to meet their around-the-clock electricity requirements. Improvements in energy efficiency of lighting, appliances, equipment and building materials will also affect energy consumption by customers. Changes in power generation, storage, and use technologies could have significant effects on customer behaviors and their energy consumption. These developments could affect levels of customer-owned generation, customer expectations, and current business models and make portions of the Utility Registrants' transmission and/or distribution facilities uneconomic prior to the end of their useful lives. Increasing pressure from both the private and public sectors to take actions to mitigate climate change could also push the speed and nature of this transition. These factors could affect the Registrants consolidated financial statements through, among other things, increased operating and maintenance expenses, increased capital expenditures, and potential asset impairment charges or accelerated depreciation over shortened remaining asset useful lives. Market performance and other factors could decrease the value of employee benefit plan assets and could increase the related employee benefit plan obligations, which then could require significant additional funding (All Registrants). Disruptions in the capital markets and their actual or perceived effects on particular businesses and the greater economy could adversely affect the value of the investments held within Exelons employee benefit plan trusts. The asset values are subject to market fluctuations and will yield uncertain returns, which could fall below Exelon's projected return rates. A decline in the market value of the pension and OPEB plan assets would increase the funding requirements associated with Exelons pension and OPEB plan obligations. Additionally, Exelons pension and OPEB plan liabilities are sensitive to changes in interest rates. As interest rates decrease, the liabilities increase, potentially increasing benefit costs and funding requirements. Changes in demographics, including increased numbers of retirements or changes in life expectancy assumptions or changes to Social Security or Medicare eligibility requirements could also increase the costs and funding requirements of the obligations related to the pension and OPEB plans. See Note 14 Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information. The Registrants could be negatively affected by unstable capital and credit markets (All

Registrants). The Registrants rely on the capital markets, particularly for publicly offered debt, as well as the banking and commercial paper markets, to meet their financial commitments and short-term liquidity needs. Disruptions in the capital and credit markets in the United States or abroad could negatively affect the Registrants ability to access the capital markets or draw on their respective bank revolving credit facilities. The banks may not be able to meet their funding commitments to the Registrants if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests within a short period of time. The inability to access capital markets or credit facilities, and longer-term disruptions in the capital and credit markets because of uncertainty, changing or increased regulation, reduced alternatives, or failures of significant financial institutions could result in the deferral of discretionary capital expenditures, or require a reduction in dividend payments or other discretionary uses of cash. In addition, the Registrants have exposure to worldwide financial markets, including Europe, Canada, and Asia. Disruptions in these markets could reduce or restrict the Registrants ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of December 31, 2022, approximately 23%, 10%, and 16% of the Registrants available credit facilities were with European, Canadian, and Asian banks, respectively. Additionally, higher interest rates may put pressure on the Registrants overall liquidity profile, financial health and impact financial results. See Note 16 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the credit facilities. If any of the Registrants were to experience a downgrade in its credit ratings to below investment grade or otherwise fail to satisfy the credit standards in its agreements with its counterparties or regulatory financial requirements, it would be required to provide significant amounts of collateral that could affect its liquidity and could experience higher borrowing costs (All Registrants). The Utility Registrants' operating agreements with PJM and PECO's, BGE's, and DPL's natural gas procurement contracts contain collateral provisions that are affected by their credit rating and market prices. If certain wholesale market conditions were to exist and the Utility Registrants were to lose their investment grade credit ratings (based on their senior unsecured debt ratings), they would be required to provide collateral in the forms of letters of credit or cash, which could have a material adverse effect upon their remaining sources of liquidity. PJM collateral posting requirements will generally increase as market prices rise and decrease as market prices fall. Collateral posting requirements for PECO, BGE, and DPL, with respect to their natural gas supply contracts, will generally increase as forward market prices fall and decrease as forward market prices rise. If the Utility Registrants were downgraded, they could experience higher borrowing costs as a result of the downgrade. In addition, changes in ratings methodologies by the agencies could also have an adverse negative impact on the ratings of the Utility Registrants. The Utility Registrants conduct their respective businesses and operate under governance models and other arrangements and procedures intended to assure that the Utility Registrants are treated as separate, independent companies, distinct from Exelon and other Exelon subsidiaries in order to isolate the Utility Registrants from Exelon and other Exelon subsidiaries in the event of financial difficulty at Exelon or another Exelon subsidiary. These measures (commonly referred to as ring-fencing) could help avoid or limit a downgrade in the credit ratings of the Utility Registrants in the event of a reduction in the credit rating of Exelon. Despite these ring-fencing measures, the credit ratings of the Utility Registrants could remain linked, to some degree, to the credit ratings of Exelon. Consequently, a reduction in the credit rating of Exelon could result in a reduction of the credit rating of some or all of the Utility Registrants. A reduction in the credit rating of a Utility Registrant could have a material adverse effect on the Utility Registrant. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS Liquidity and Capital Resources Credit Matters and Cash Requirements Security Ratings for additional information regarding the potential impacts of credit downgrades on the Registrants cash flows. The impacts of significant economic downturns or increases in customer rates, could lead to decreased volumes delivered and increased expense for uncollectible customer balances (All Registrants). The impacts of significant economic downturns on the Utility Registrants' customers and the related regulatory limitations on residential service terminations for the Utility Registrants, could result in an increase in the number of uncollectible customer balances and related expense. Further, increases in customer rates, including those related to increases in purchased power and natural gas prices, could result in declines in customer usage and lower revenues for the Utility Registrants that do not have decoupling mechanisms. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information on the Registrants credit risk. Public health crises, epidemics, or pandemics, such as COVID-19 could negatively impact the Registrants' results (All Registrants). COVID-19 disrupted economic activity in the Registrants respective markets and negatively affected the Registrants results of operations in 2020. However, the financial impacts were not material for the years ended December 31, 2021 and December 31, 2022, other than the 2022 impairment disclosure within Note 11 Asset Impairments. The Registrants cannot predict the full extent of the impacts of COVID-19, which will depend on, among other things, the rate, and public perceptions of the effectiveness, of vaccinations and rate of resumption of business activity. In addition, any future widespread pandemic or other local or global health issue could adversely affect our vendors, competitors or customers and customer demand as well as the Registrants ability to operate their transmission and distribution assets. See Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - Executive Overview for additional information. The Registrants could be negatively affected by the impacts of weather (All Registrants). Weather conditions directly influence the demand for electricity and natural gas and affect the price of energy commodities. Temperatures above normal levels in the summer tend to increase summer cooling electricity demand and revenues, and temperatures below normal levels in the winter tend to increase winter heating electricity and gas demand and revenues. Moderate temperatures adversely affect the usage of energy and resulting operating revenues at PECO and DPL Delaware. Due to revenue decoupling, operating revenues from electric distribution at ComEd, BGE, Pepco, DPL Maryland, and ACE are not affected by abnormal weather. Extreme weather conditions or damage resulting from storms could stress the Utility Registrants' transmission and distribution systems, communication systems, and technology, resulting in increased maintenance and capital costs and limiting each companys ability to meet peak customer demand. First and third quarter financial results, in particular, are substantially dependent on weather conditions, and could make period comparisons less relevant. Climate change projections suggest increases to summer temperature and humidity trends, as well as more erratic precipitation and storm patterns over the long-term in the areas where the Utility Registrants have transmission and distribution assets. The frequency in which weather conditions emerge outside the current expected climate norms could contribute to weather-related impacts discussed above. Long-lived assets, goodwill, and other assets could become impaired (All Registrants). Long-lived assets represent the single largest asset class on the Registrants statements of financial position. In addition, Exelon, ComEd, and PHI have material goodwill balances. The Registrants evaluate the recoverability of the carrying value of long-lived assets to be held and used whenever events or circumstances indicating a potential impairment exist. Factors such as, but not limited to, the business climate, including current and future energy and market conditions, environmental regulation, and the condition of assets are considered. ComEd and PHI perform an assessment for possible impairment of their goodwill at least annually or more frequently if an event occurs or circumstances change that would more likely than not reduce the fair value of the reporting units below their carrying amount. Regulatory actions or changes in significant assumptions, including discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows for ComEds, Pepcos, DPLs, and ACEs business, and the fair value of debt, could potentially result in future impairments of Exelons, ComEd's, and PHIs goodwill. An impairment would require the Registrants to reduce the carrying value of the long-lived asset or goodwill to fair value through a non-cash charge to expense by the amount of the impairment. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS Critical Accounting Policies and Estimates, Note 7 Property, Plant, and Equipment, Note 11 Asset Impairments, and Note 12 Intangible Assets of the Combined Notes to the Consolidated Financial Statements for additional information on long-lived asset impairments and goodwill impairments. The Registrants could incur substantial costs in the event of non-performance by third-parties under indemnification agreements, or when the Registrants have guaranteed their performance (All Registrants). The Registrants have entered into various agreements with counterparties that require those counterparties to reimburse a Registrant and hold it harmless against specified obligations and claims. To the extent that any of these counterparties are affected by deterioration in their creditworthiness or the agreements are otherwise determined to be unenforceable, the affected Registrant could be held responsible for the obligations. Each of the Utility Registrants has transferred its former generation business to a third party and in each case the transferee has agreed to assume certain obligations and to indemnify the applicable Utility Registrant for such obligations. In connection with the restructurings under which ComEd, PECO, and BGE transferred their generating assets to Constellation, Constellation assumed certain of ComEds, PECOs, and BGE's rights and obligations with respect to their former generation businesses. Further, ComEd, PECO, and BGE have entered into agreements with third parties under which the third-party agreed to indemnify ComEd, PECO, or BGE for certain obligations related to their respective former generation businesses that have been assumed by Constellation as part of the restructuring. If the third-party, Constellation, or the transferee of Pepco's, DPL's, or ACEs generation facilities experienced events that reduced its creditworthiness or the indemnity arrangement became unenforceable, the applicable Utility Registrant could be liable for any existing or future claims. In addition, the Utility Registrants have residual liability under certain laws in connection with their former generation facilities. The Registrants have issued indemnities to third parties regarding environmental or other matters in connection with purchases and sales of assets, including several of the Utility Registrants in connection with Constellation's absorption of their former generating assets. The Registrants could incur substantial costs to fulfill their obligations under these indemnities. The Registrants have issued guarantees of the performance of third parties, which obligate the Registrants to perform if the third parties do not perform. In the event of non-performance by those third parties, the Registrants could incur substantial cost to fulfill their obligations under these guarantees. Risks Related to Legislative, Regulatory, and Legal Factors The Registrants' businesses are highly regulated and electric and gas revenue and earnings could be negatively affected by legislative and/or regulatory actions (All Registrants). Substantial aspects of the Registrants' businesses are subject to comprehensive Federal or state legislation and/or regulation. The Utility Registrants' consolidated financial statements are heavily dependent on the ability of the Utility Registrants to recover their costs for the retail purchase, transmission, and distribution of power and natural gas to their customers. Fundamental changes in regulations or adverse legislative actions affecting the Registrants businesses would require changes in their business planning models and operations. The Registrants cannot predict when or whether legislative or regulatory proposals could become law or what their effect would be on the Registrants. Changes in the Utility Registrants' respective terms and conditions of service, including their respective rates, along with adoption of new rate structures and constructs, or establishment of new rate cases, are subject to regulatory approval proceedings and/or negotiated settlements that are at times contentious, lengthy, and subject to appeal, which lead to uncertainty as to the ultimate result, and which could introduce time delays in effectuating rate changes (All Registrants). The Utility Registrants are required to engage in regulatory approval proceedings as a part of the process of establishing the terms and rates for their respective services, adoption of new rate structures and constructs or establishment of new rate cases. These proceedings typically involve multiple parties, including governmental bodies and officials, consumer advocacy groups, and various consumers of energy, who have differing concerns but who have the common objective of limiting rate increases or even reducing rates. Decisions are subject to appeal, potentially leading to additional uncertainty associated with the approval proceedings. The potential duration of such proceedings creates a risk that rates ultimately approved by the applicable regulatory body may not be sufficient for a Utility Registrant to recover its costs by the time the rates become effective. Established rates are also subject to subsequent prudency reviews by state regulators, whereby various portions of rates could be adjusted, subject to refund or disallowed, including recovery mechanisms for costs associated with the procurement of electricity or gas, credit losses, MGP remediation, smart grid infrastructure, and energy efficiency and demand response programs. In certain instances, the Utility Registrants could agree to negotiated settlements related to various rate matters, customer initiatives, or franchise agreements. These settlements are subject to regulatory approval. The ultimate outcome and timing of regulatory rate proceedings have a significant effect on the ability of the Utility Registrants to recover their costs or earn an adequate return. See Note 3 Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for additional information. The Registrants could be subject to higher costs and/or penalties related to mandatory reliability standards, including the likely exposure of the Utility Registrants to the results of PJMs RTEP and NERC compliance requirements (All Registrants). The Utility Registrants as users, owners, and operators of the bulk power transmission system are subject to mandatory reliability standards promulgated by NERC and enforced by FERC. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with or changes in the reliability standards could subject the Registrants to higher operating costs and/or increased capital expenditures. In addition, the ICC, PAPUC, MDPSC, DCPSC, DEPSC, and NJBPU impose certain distribution reliability standards on the Utility Registrants. If the Utility Registrants were found in non-compliance with the Federal and state mandatory reliability standards, they could be subject to remediation costs as well as sanctions, which could include substantial monetary penalties. The Registrants could incur substantial costs to fulfill their obligations related to environmental and other matters (All Registrants). The Registrants are subject to extensive environmental regulation and legislation by local, state, and Federal authorities. These laws and regulations affect the way the Registrants conduct their operations and make capital expenditures including how they handle air and water emissions, hazardous and solid waste, and activities affecting surface waters, groundwater, and aquatic and other species. Violations of these requirements could subject the Registrants to enforcement actions, capital expenditures to bring existing facilities into compliance, additional operating costs for remediation and clean-up costs, civil penalties and exposure to third parties claims for alleged health or property damages, or operating restrictions to achieve compliance. In addition, the Registrants are subject to liability under these laws for the remediation costs for environmental contamination of property now or formerly owned by the Registrants and of property contaminated by hazardous substances they generated or released. Remediation activities associated with MGP operations conducted by predecessor companies are one component of such costs. Also, the Registrants are currently involved in several proceedings relating to sites where hazardous substances have been deposited and could be subject to additional proceedings in the future. See ITEM 1. BUSINESS Environmental Matters and Regulation for additional information. The Registrants could be negatively affected by federal and state RPS and/or energy conservation legislation, along with energy conservation by customers (All Registrants). Changes to current state legislation or the development of Federal legislation that requires the use of clean, renewable, and alternate fuel sources could significantly impact the Utility Registrants, especially if timely cost recovery is not allowed. Federal and state legislation mandating the implementation of energy conservation programs that require the implementation of new technologies, such as smart meters and smart grid, could increase capital expenditures and could significantly impact the Utility Registrants consolidated financial statements if timely cost recovery is not allowed. These energy conservation programs, regulated energy consumption reduction targets, and new energy consumption technologies could cause declines in customer energy consumption and lead to a decline in the Registrants' earnings, if timely recovery is not allowed. See ITEM 1. BUSINESS Environmental Matters and Regulation Renewable and Clean Energy Standards and "The Registrants are potentially affected by emerging technologies that could over time affect or transform the energy industry" above for additional information. The Registrants could be negatively affected by challenges to tax positions taken, tax law changes, and the inherent difficulty in quantifying potential tax effects of business decisions. (All Registrants). The Registrants are required to make judgments to estimate their obligations to taxing authorities, which includes general tax positions taken and associated reserves established. Tax obligations include, but are not limited to: income, real estate, sales and use, and employment-related taxes and ongoing appeal issues related to these tax matters. All tax estimates could be subject to challenge by the tax authorities. Additionally, earnings may be impacted due to changes in federal or local/state tax laws, and the inherent difficulty of estimating potential tax effects of ongoing business decisions. See Note 1 Significant Accounting Policies and Note 13 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information. Legal proceedings could result in a negative outcome, which the Registrants cannot predict (All Registrants). The Registrants are involved in legal proceedings, claims, and litigation arising out of their business operations. The material ones are summarized in Note 18 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements. Adverse outcomes in these proceedings could require significant expenditures, result in lost revenue, or restrict, or disrupt business activities. The Registrants could be subject to adverse publicity and reputational risks, which make them vulnerable to negative customer perception and could lead to increased regulatory oversight or other consequences (All Registrants). The Registrants could be the subject of public criticism. Adverse publicity of this nature could render public service commissions and other regulatory and legislative authorities less likely to view energy companies in a favorable light, and could cause those companies, including the Registrants, to be susceptible to less favorable legislative and regulatory outcomes, as well as increased regulatory oversight and more stringent legislative or regulatory requirements. Exelon and ComEd have received requests for information related to an SEC investigation into their lobbying activities. The outcome of the investigations could have a material adverse effect on their reputation and consolidated financial statements (Exelon and ComEd). On October 22, 2019, the SEC notified Exelon and ComEd that it had opened an investigation into their lobbying activities in the state of Illinois. Exelon and ComEd have cooperated fully, including by providing all information requested by the SEC, and intend to continue to cooperate fully and expeditiously with the SEC. The outcome of the SECs investigation cannot be predicted and could subject Exelon and ComEd to civil penalties, sanctions, or other remedial measures. Any of the foregoing, as well as the appearance of non-compliance with anti-corruption and anti-bribery laws, could have an adverse impact on Exelons and ComEds reputations or relationships with regulatory and legislative authorities, customers, and other stakeholders, as well as their consolidated financial statements. See Note 18 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements. If ComEd violates its Deferred Prosecution Agreement announced on July 17, 2020, it could have an adverse effect on the reputation and consolidated financial statements of Exelon and ComEd (Exelon and ComEd). On July 17, 2020, ComEd entered into a Deferred Prosecution Agreement (DPA) with the U.S. Attorneys Office for the Northern District of Illinois (USAO) to resolve the USAOs investigation into Exelons and ComEds lobbying activities in the State of Illinois. Exelon was not made a party to the DPA and the investigation by the USAO into Exelons activities ended with no charges being brought against Exelon. Under the DPA, the USAO filed a single charge alleging that ComEd improperly gave and offered to give jobs, vendor subcontracts, and payments associated with those jobs and subcontracts for the benefit of the Speaker of the Illinois House of Representatives and the Speakers associates, with the intent to influence the Speakers action regarding legislation affecting ComEds interests. The DPA provides that the USAO will defer any prosecution of such charge and any other criminal or civil case against ComEd in connection with the matters identified therein for a three-year period subject to certain obligations of ComEd, including, but not limited to, the following: (i) payment to the U.S. Treasury of $200 million; (ii) continued full cooperation with the governments investigation; and (iii) ComEds adoption and maintenance of remedial measures involving compliance and reporting undertakings as specified in the DPA. If ComEd is found to have breached the terms of the DPA, the USAO may elect to prosecute, or bring a civil action against, ComEd for conduct alleged in the DPA or known to the government, which could result in fines or penalties and could have an adverse impact on Exelons and ComEds reputation or relationships with regulatory and legislative authorities, customers and other stakeholders, as well as their consolidated financial statements. See Note 18 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements. Risks Related to Operational Factors The Registrants are subject to risks associated with climate change (All Registrants). The Registrants periodically perform analyses to better understand long-term projections of climate change and how those changes in the physical environments where they operate could affect their facilities and operations. The Registrants primarily operate in the Midwest and Mid-Atlantic of the United States, areas that historically have been prone to various types of severe weather events, and as such the Registrants have well-developed response and recovery programs based on these historical events. However, the Registrants physical facilities could be at greater risk of damage as changes in the global climate affect temperature and weather patterns, or be placed at greater risk of damage should climate changes result in more intense, frequent and extreme weather events, elevated levels of precipitation, sea level rise, increased surface water temperatures, and/or other effects. Over time, the Registrants are making additional investments to protect their facilities from physical climate-related risks. In addition, changes to the climate may impact levels and patterns of demand for energy and related services, which could affect Registrants operations. Over time, the Registrants are making additional investments to adapt to changes in operational requirements to manage demand changes and customer expectations caused by climate change. Climate Change risks include changes to the energy systems due to new technologies, changing customer expectations and/or voluntary GHG goals, as well as local, state, or federal regulatory requirements intended to reduce GHG emissions. The Registrants also periodically perform analyses of potential energy system transition pathways to reduce economy-wide GHG emissions to mitigate climate change. To the extent additional GHG reduction legislation and/or regulation becomes effective at the Federal and/or state levels, the Registrants could incur costs to further limit the GHG emissions from their operations or otherwise comply with applicable requirements. See ITEM 1. BUSINESS Environmental Matters and Regulation Climate Change and ITEM 1.A. "The Registrants are potentially affected by emerging technologies that could over time affect or transform the energy industry" above for additional information. The Utility Registrants' operating costs are affected by their ability to maintain the availability and reliability of their delivery and operational systems (All Registrants). Failures of the equipment or facilities used in the Utility Registrants' delivery systems could interrupt the electric transmission and electric and natural gas delivery, which could result in a loss of revenues and an increase in maintenance and capital expenditures. Equipment or facilities failures can be due to several factors, including natural causes such as weather or information systems failure. Specifically, if the implementation of AMI, smart grid, or other technologies in the Utility Registrants' service territory fail to perform as intended or are not successfully integrated with billing and other information systems, or if any of the financial, accounting, or other data processing systems fail or have other significant shortcomings, the Utility Registrants' financial results could be negatively impacted. In addition, dependence upon automated systems could further increase the risk that operational system flaws or internal and/or external tampering or manipulation of those systems will result in losses that are difficult to detect. Regulated utilities, which are required to provide service to all customers within their service territory, have generally been afforded liability protections against claims by customers relating to failure of service. Under Illinois law, however, ComEd could be required to pay damages to its customers in some circumstances involving extended outages affecting large numbers of its customers, which could be material. The Registrants are subject to physical security and cybersecurity risks (All Registrants). The Registrants face physical security and cybersecurity risks. Threat sources, including sophisticated nation-state actors, continue to seek to exploit potential vulnerabilities in the electric and natural gas utility industry, grid infrastructure, and other energy infrastructures, and these attacks and disruptions, both physical and cyber, are becoming increasingly sophisticated and dynamic. Continued implementation of advanced digital technologies increases the potentially unfavorable impacts of such attacks. Additionally, the U.S. government has warned that the Ukraine conflict may increase the risks of attacks targeting critical infrastructure in the United States. A security breach of the Registrants' physical assets or information systems or those of the Registrants competitors, vendors, business partners and interconnected entities in RTOs and ISOs, or regulators could materially impact Registrants by, among other things, impairing the availability of electricity and gas distributed by Registrants and/or the reliability of transmission and distribution systems, impairing the availability of vendor services and materials that the Registrants rely on to maintain their operations, or by leading to the theft or inappropriate release of certain types of information, including critical infrastructure information, sensitive customer, vendor, or employee data, or other confidential data. The risk of these events and security breaches occurring continues to intensify, and while the Registrants have been, and will likely continue to be, subjected to physical and cyber-attacks, to date none have directly experienced a material breach or material disruption to its network or information systems or our operations. However, as such attacks continue to increase in sophistication and frequency, the Registrants may be unable to prevent all such attacks in the future. If a significant security breach were to occur, the Registrants' reputation could be negatively affected, customer confidence in the Registrants or others in the industry could be diminished, or the Registrants could be subject to legal claims, loss of revenues, increased costs, or operations shutdown. Moreover, the amount and scope of insurance maintained against losses resulting from any such security breaches may not be sufficient to cover losses or otherwise adequately compensate for any disruptions to business that could result. The Utility Registrants' deployment of smart meters throughout their service territories could increase the risk of damage from an intentional disruption of the system by third parties. In addition, new or updated security regulations or unforeseen threat sources could require changes in current measures taken by the

Registrants or their business operations and could adversely affect their consolidated financial statements. The Registrants employees, contractors, customers, and the general public could be exposed to a risk of injury due to the nature of the energy industry (All Registrants). Employees and contractors throughout the organization work in, and customers and the general public could be exposed to, potentially dangerous environments near the Registrants operations. As a result, employees, contractors, customers, and the general public are at some risk for serious injury, including loss of life. These risks include gas explosions, pole strikes, and electric contact cases. Natural disasters, war, acts and threats of terrorism, pandemic, and other significant events could negatively impact the Registrants' results of operations, ability to raise capital and future growth (All Registrants). The Utility Registrants' distribution and transmission infrastructures could be affected by natural disasters and extreme weather events, which could result in increased costs, including supply chain costs. An extreme weather event within the Utility Registrants service areas can also directly affect their capital assets, causing disruption in service to customers due to downed wires and poles or damage to other operating equipment. The impact that potential terrorist attacks could have on the industry and the Registrants is uncertain. The Registrants face a risk that their operations would be direct targets or indirect casualties of an act of terror. Any retaliatory military strikes or sustained military campaign could affect their operations in unpredictable ways, such as changes in insurance markets and disruptions of fuel supplies and markets, particularly oil. Furthermore, these catastrophic events could compromise the physical or cybersecurity of the Registrants' facilities, which could adversely affect the Registrants' ability to manage their businesses effectively. Instability in the financial markets as a result of terrorism, war, natural disasters, pandemic, credit crises, recession, or other factors also could result in a decline in energy consumption or interruption of fuel or the supply chain. In addition, the implementation of security guidelines and measures has resulted in and is expected to continue to result in increased costs. The Registrants could be significantly affected by the outbreak of a pandemic. Exelon has plans in place to respond to a pandemic. However, depending on the severity of a pandemic and the resulting impacts to workforce and other resource availability, the ability to operate Exelon's transmission and distribution assets could be adversely affected. In addition, Exelon maintains a level of insurance coverage consistent with industry practices against property, casualty, and cybersecurity losses subject to unforeseen occurrences or catastrophic events that could damage or destroy assets or interrupt operations. However, there can be no assurance that the amount of insurance will be adequate to address such property and casualty losses. The Registrants businesses are capital intensive, and their assets could require significant expenditures to maintain and are subject to operational failure or be impacted by lack of availability of critical parts, which could result in potential liability (All Registrants). The Utility Registrants businesses are capital intensive and require significant investments in transmission and distribution infrastructure projects. Equipment, even if maintained in accordance with good utility practices, is subject to operational failure, including events that are beyond the Utility Registrants control, and could require significant expenditures to operate efficiently. Additionally, if critical parts are not available, it may impact the timing of execution of capital projects. The Registrants' consolidated financial statements could be negatively affected if they were unable to effectively manage their capital projects or raise the necessary capital, or if they are deemed liable for operational failure. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS Liquidity and Capital Resources for additional information regarding the Registrants potential future capital expenditures. The Utility Registrants' respective ability to deliver electricity, their operating costs, and their capital expenditures could be negatively impacted by transmission congestion and failures of neighboring transmission systems (All Registrants). Demand for electricity within the Utility Registrants' service areas could stress available transmission capacity requiring alternative routing or curtailment of electricity usage. Also, insufficient availability of electric supply to meet customer demand could jeopardize the Utility Registrants' ability to comply with reliability standards and strain customer and regulatory agency relationships. As with all utilities, potential concerns over transmission capacity or generation facility retirements could result in PJM or FERC requiring the Utility Registrants to upgrade or expand their respective transmission systems through additional capital expenditures. PJMs systems and operations are designed to ensure the reliable operation of the transmission grid and prevent the operations of one utility from having an adverse impact on the operations of the other utilities. However, service interruptions at other utilities may cause interruptions in the Utility Registrants service areas. The Registrants' performance could be negatively affected if they fail to attract and retain an appropriately qualified workforce (All Registrants). Certain events, such as the separation transaction, an employee strike, loss of employees, loss of contract resources due to a major event, and an aging workforce without appropriate replacements, could lead to operating challenges and increased costs for the Registrants. The challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. In this case, costs, including costs for contractors to replace employees, productivity costs, and safety costs, could arise. The Registrants are particularly affected due to the specialized knowledge required of the technical and support employees for their transmission and distribution operations as well as areas where new technologies are pertinent. The Registrants performance could be negatively affected by poor performance of third-party contractors that perform periodic or ongoing work (All Registrants). All Registrants rely on third-party contractors to perform operations, maintenance, and construction work. Performance standards typically are included in all contractual obligations, but poor performance may impact the capital execution plan or operations, or have adverse financial or reputational consequences. The Registrants could make acquisitions or investments in new business initiatives and new markets, which may not be successful or achieve the intended financial results (All Registrants). The Utility Registrants face risks associated with their regulatory-mandated initiatives, such as smart grids and and broader beneficial electrification. These risks include, but are not limited to, cost recovery, regulatory concerns, cybersecurity, and obsolescence of technology. Such initiatives may not be successful. Risks Related to the Separation (Exelon) The separation may not achieve some or all of the benefits anticipated by Exelon and, following the separation, Exelon's common stock price may underperform relative to Exelon's expectations. By separating the Utility Registrants and Constellation, Exelon created two publicly traded companies with the resources necessary to best serve customers and sustain long-term investment and operating excellence. The separate companies are expected to create value by having the strategic flexibility to focus on their unique customer, market and community priorities. However, the separation may not provide such results on the scope or scale that Exelon anticipates, and Exelon may not realize the anticipated benefits of the separation. Failure to do so could have a material adverse effect on Exelon's financial statements and its common stock price. In connection with the separation into two public companies, Exelon and Constellation will indemnify each other for certain liabilities. If Exelon is required to pay under these indemnities to Constellation, Exelon's financial results could be negatively impacted. The Constellation indemnities may not be sufficient to hold Exelon harmless from the full amount of liabilities for which Constellation will be allocated responsibility, and Constellation may not be able to satisfy its indemnification obligations in the future. Pursuant to the separation agreement and certain other agreements between Exelon and Constellation, each party will agree to indemnify the other for certain liabilities, in each case for uncapped amounts. Indemnities that Exelon may be required to provide Constellation are not subject to any cap, may be significant and could negatively impact its business. Third parties could also seek to hold Exelon responsible for any of the liabilities that Constellation has agreed to retain. Any amounts Exelon is required to pay pursuant to these indemnification obligations and other liabilities could require Exelon to divert cash that would otherwise have been used in furtherance of its operating business. Further, the indemnities from Constellation for Exelon's benefit may not be sufficient to protect Exelon against the full amount of such liabilities, and Constellation may not be able to fully satisfy its indemnification obligations. Moreover, even if Exelon ultimately succeeds in recovering from Constellation any amounts for which Exelon is held liable, Exelon may be temporarily required to bear these losses. Each of these risks could negatively affect Exelon's business, results of operations and financial condition. ##TABLE_START

Ticker: FE, Sector: Utilities, Filed At: 2023-02-13T17:01:49-05:00

ITEM 1. BUSINESS The Companies FE and its subsidiaries are principally involved in the transmission, distribution, and generation of electricity. FirstEnergys ten utility operating companies comprise one of the nations largest investor-owned electric systems, based on serving over six million customers in the Midwest and Mid-Atlantic regions. FirstEnergys transmission operations include over 24,000 miles of transmission lines and two regional transmission operation centers. AGC and MP control 3,580 MWs of total capacity. FirstEnergys revenues are primarily derived from electric service provided by the Utilities and Transmission Companies. Regulated Utility Operating Subsidiaries The Utilities combined service areas encompass approximately 65,000 square miles in Ohio, Pennsylvania, West Virginia, Maryland, New Jersey, and New York. The areas they serve have a combined population of approximately 14 million. OE owns property and does business as an electric public utility in Ohio. OE engages in the distribution and sale of electric energy to communities in central and northeastern Ohio. The area it serves has a population of approximately 2.4 million. Penn owns property and does business as an electric public utility in Pennsylvania. Penn furnishes electric service to communities in western Pennsylvania. The area it serves has a population of approximately 0.4 million. CEI does business as an electric public utility in Ohio. CEI engages in the distribution and sale of electric energy in northeastern Ohio. The area it serves has a population of approximately 1.7 million. TE does business as an electric public utility in Ohio. TE engages in the distribution and sale of electric energy in northwestern Ohio. The area it serves has a population of approximately 0.7 million. JCPL owns property and does business as an electric public utility in New Jersey. JCPL provides transmission and distribution services in northern, western, and east central New Jersey. The area it serves has a population of approximately 2.9 million. ME owns property and does business as an electric public utility in Pennsylvania. ME provides distribution services in eastern and south central Pennsylvania. The area it serves has a population of approximately 1.3 million. PN owns property and does business as an electric public utility in Pennsylvania. PN provides distribution services in western, northern, and south central Pennsylvania. The area PN serves has a population of approximately 1.2 million. Also, PN, as lessee of the property of its subsidiary, the Waverly Electric Light Power Company, serves approximately 4,000 customers in the Waverly, New York vicinity. PE owns property and does business as an electric public utility in Maryland, Virginia, and West Virginia. PE provides transmission and distribution services in portions of Maryland and West Virginia and provides transmission services in Virginia. The area it serves has a population of approximately 1.0 million. MP owns property and does business as an electric public utility in West Virginia. MP provides generation, transmission, and distribution services in northern West Virginia. The area it serves has a population of approximately 0.8 million. MP is contractually obligated to provide power to PE to meet its load obligations in West Virginia. MP owns or contractually controls 3,580 MWs of generation capacity that is supplied to its electric utility business, including a 16.25% undivided interest in the Bath County pumped-storage hydroelectric generation facility in Virginia (487 MWs) through its wholly owned subsidiary AGC. WP owns property and does business as an electric public utility in Pennsylvania. WP provides transmission and distribution services in southwestern, south-central, and northern Pennsylvania. The area it serves has a population of approximately 1.6 million. FirstEnergy is proceeding with the consolidation of the Pennsylvania Companies into a new, single operating entity. The PA Consolidation will require, among other steps: (a) the transfer of certain Pennsylvania-based transmission assets owned by WP to KATCo, (b) the transfer of Class B equity interests of MAIT currently held by PN and ME to FE (and ultimately transferred to FET as part of the FET Minority Equity Interest Sale), (c) the formation of PA NewCo and (d) the merger of each of the Pennsylvania Companies with and into PA NewCo, with PA NewCo surviving such mergers as the successor-in-interest to all assets and liabilities of the Pennsylvania Companies. Following completion of the PA Consolidation, PA NewCo will be FEs only regulated utility in Pennsylvania encompassing the operations previously conducted individually by the Pennsylvania Companies. Consummation of the PA Consolidation is contingent upon numerous conditions, including the approval of NYPSC, PPUC and FERC. Subject to receipt of such regulatory approvals, FirstEnergy expects that the PA Consolidation will close by early 2024. Regulated

Transmission Operating Subsidiaries FET, the parent of ATSI, MAIT, PATH, and TrAIL, is a subsidiary of FE which holds 80.1% of its issued and outstanding membership interests. Brookfield owns the remaining 19.9% of the issued and outstanding membership interests of FET. Through its subsidiaries, FET owns and operates high-voltage transmission facilities in the PJM Region. FET's subsidiaries are subject to regulation by FERC and applicable state regulatory authorities. On February 2, 2023, FE, along with FET, entered into the FET PSA II with Brookfield and the Brookfield Guarantors, pursuant to which FE agreed to sell to Brookfield at the closing, and Brookfield agreed to purchase from FE, an incremental 30% equity interest in FET for a purchase price of $3.5 billion. The purchase price will be payable in part by the issuance of a promissory note expected to be in the principal amount of $1.75 billion. The remaining $1.75 billion of the purchase price will be payable in cash at the closing. As a result of the consummation of the transaction, Brookfields interest in FET will increase from 19.9% to 49.9%, while FE will retain the remaining 50.1% ownership interests of FET. The transaction is subject to customary closing conditions, including approval from the FERC and certain state utility commissions, and completion of review by the CFIUS. In addition, pursuant to the FET PSA II, FirstEnergy has agreed to make the necessary filings with the applicable regulatory authorities for the PA Consolidation. The FET Minority Equity Interest Sale is expected to close by early 2024. Upon closing, FET will continue to be consolidated in FirstEnergys GAAP financial statements. ATSI owns high-voltage transmission facilities in PJM, which consist of approximately 7,900 circuit miles of transmission lines with nominal voltages of 345 kV, 138 kV and 69 kV in Ohio and Pennsylvania. TrAIL owns high-voltage transmission facilities in PJM, which consists of approximately 260 circuit miles of transmission lines, including a 500 kV transmission line extending approximately 150 miles from southwestern Pennsylvania through West Virginia to a point of interconnection with VEPCO in northern Virginia. MAIT owns high-voltage transmission facilities in PJM, which consist of approximately 4,300 circuit miles of transmission lines with nominal voltages of 500 kV, 345 kV, 230 kV, 138 kV, 115 kV, 69 kV and 46 kV in Pennsylvania. KATCo was formed to accommodate new transmission construction in the WP, MP and PE footprint and currently does not own or operate any transmission assets. Service Company FESC provides legal, financial, and other corporate support services at cost, in accordance with its cost allocation manual, to affiliated FirstEnergy companies. Operating Segments FirstEnergy's reportable operating segments are comprised of the Regulated Distribution and Regulated Transmission segments. The Regulated Distribution segment distributes electricity through FirstEnergys ten utility operating companies, serving approximately six million customers within 65,000 square miles of Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York, and purchases power for its POLR, SOS, SSO and default service requirements in Ohio, Pennsylvania, New Jersey, and Maryland. This segment also controls 3,580 MWs of regulated electric generation capacity located primarily in West Virginia and Virginia. The segment's results reflect the costs of securing and delivering electric generation from transmission facilities to customers, including the deferral and amortization of certain related costs. The Regulated Transmission segment provides transmission infrastructure owned and operated by the Transmission Companies and certain of FirstEnergy's utilities (JCPL, MP, PE and WP) to transmit electricity from generation sources to distribution facilities. The segment's revenues are primarily derived from forward-looking formula rates. Under forward-looking formula rates, the revenue requirement is updated annually based on a projected rate base and projected costs, which is subject to an annual true-up based on actual rate base and costs. The segment's results also reflect the net transmission expenses related to the delivery of electricity on FirstEnergy's transmission facilities. On November 6, 2021, FirstEnergy, along with FET, entered into the FET PSA I, with Brookfield and the Brookfield Guarantors pursuant to which FET agreed to issue and sell to Brookfield at the closing, and Brookfield agreed to purchase from FET, certain newly issued membership interests of FET, such that Brookfield would own 19.9% of the issued and outstanding membership interests of FET, for a purchase price of $2.375 billion. The transaction closed on May 31, 2022. On February 2, 2023, FE, along with FET, entered into the FET PSA II with Brookfield and the Brookfield Guarantors, pursuant to which FE agreed to sell to Brookfield at the closing, and Brookfield agreed to purchase from FE, an incremental 30% equity interest in FET for a purchase price of $3.5 billion. The purchase price will be payable in part by the issuance of a promissory note expected to be in the principal amount of $1.75 billion. The remaining $1.75 billion of the purchase price will be payable in cash at the closing. As a result of the consummation of the transaction, Brookfields interest in FET will increase from 19.9% to 49.9%, while FE will retain the remaining 50.1% ownership interests of FET. The transaction is subject to customary closing conditions, including approval from the FERC and certain state utility commissions, and completion of review by the CFIUS. In addition, pursuant to the FET PSA II, FirstEnergy has agreed to make the necessary filings with the applicable regulatory authorities for the PA Consolidation. The FET Minority Equity Interest Sale is expected to close by early 2024. Upon closing, FET will continue to be consolidated in FirstEnergys GAAP financial statements. Corporate/Other reflects corporate support and other costs not charged or attributable to the Utilities or Transmission Companies, including FE's retained Pension and OPEB assets and liabilities of the FES Debtors, interest expense on FEs holding company debt and other investments or businesses that do not constitute an operating segment. Additionally, reconciling adjustments for the elimination of inter-segment transactions are included in Corporate/Other. As of December 31, 2022, 67 MWs of electric generating capacity, representing AE Supply's OVEC capacity entitlement, was also included in Corporate/Other for segment reporting. As of December 31, 2022, Corporate/Other had approximately $5.4 billion of FE holding company debt. Utility Regulation Regulatory Accounting FirstEnergy accounts for the effects of regulation through the application of regulatory accounting to the Utilities and the Transmission Companies since their rates are established by a third-party regulator with the authority to set rates that bind customers, are cost-based and can be charged to and collected from customers. The Utilities and the Transmission Companies recognize, as regulatory assets and regulatory liabilities, costs which FERC and the various state utility commissions, as applicable, have authorized for recovery from or return to customers in future periods or for which authorization is probable. Without the probability of such authorization, costs currently recorded as regulatory assets and regulatory liabilities would have been charged or credited to income as incurred. All regulatory assets and liabilities are expected to be recovered from or returned to customers. Based on current ratemaking procedures, the Utilities and the Transmission Companies continue to collect cost-based rates for their transmission and distribution services; accordingly, it is appropriate that the Utilities and the Transmission Companies continue the application of regulatory accounting to those operations. Regulatory accounting is applied only to the parts of the business that meet the above criteria. If a portion of the business applying regulatory accounting no longer meets those requirements, previously recorded regulatory assets and liabilities are removed from the balance sheet in accordance with GAAP. State Regulation The following table summarizes the allowed ROE and the aggregate actual ROE of the Regulated Distribution Utilities by state for the year ended December 31, 2022, as determined for regulatory purposes: ##TABLE_START State Allowed ROE Actual ROE (1) Maryland 9.65% 8.8% New Jersey 9.6% 7.0% Ohio 10.5% 8.4% Pennsylvania Settled (2) 8.1% West Virginia Settled (2) 6.6% ##TABLE_END(1) Actual ROE is based on methodology used in last distribution rate case and/or quarterly earnings reports, as applicable. Rate base is for distribution assets only (except West Virginia, which includes generation and transmission assets) and reflects the actual capital structure for Pennsylvania, West Virginia and Maryland, and the allowed capital structure for Ohio. Actual ROEs reflect actual revenue (not weather normalized) and historical results should not be relied upon to estimate the outcome of future rate cases as regulatory assumptions may vary. ROEs may not tie to upcoming rate filings due to items such as updated allocators, taxes, and adjustments. (2) Commission-approved settlement agreements did not disclose ROE rates. See "Outlook - State Regulation" in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" for additional information and discussion. Federal Regulation See "Outlook - FERC Regulatory Matters" in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" for additional information and discussion. Environmental Matters See "Outlook - Environmental Matters" in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" for additional information and discussion. Capital Requirements FirstEnergys business is capital intensive, requiring significant resources to fund operating expenses, construction and other investment expenditures, scheduled debt maturities and interest payments, dividend payments and potential contributions to its pension plan. See "Capital Resources and Liquidity" in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" for additional information and discussion. Supply Plan Supply Chain FirstEnergy has continued to experience supply chain challenges due to economic conditions following the global pandemic. Lead times continue to increase across numerous material categories, with some as much as doubling from pre-pandemic lead times. Suppliers continue to struggle with labor shortages and raw material availability, which, along with inflationary pressure, have increased the costs and decreased the availability of certain materials, equipment and contractors. FirstEnergy continues to monitor supply chain risk as it anticipates these challenges continuing into 2023 and is mitigating these risks by: Utilizing a cross-functional team to forecast potential impacts to operations and programs; Expanding supply base to increase resiliency; Enhancing the demand management and material reservation process; Evaluating substitute products, reserving production capacity, and buying ahead in targeted categories; and Staying updated by participating in discussions with other utilities through EEI, which has a long history of mutual assistance in the electric utility industry. Default Service Certain of the Utilities have default service obligations to provide power to non-shopping customers who have elected to continue to receive service under regulated retail tariffs. The volume of these sales can vary depending on the level of shopping that occurs and these default service plans vary by state and by service territory. JCPLs default service, or BGS supply, is secured through a statewide competitive procurement process approved by the NJBPU. Default service for the Ohio Companies, Pennsylvania Companies and PE's Maryland jurisdiction are provided through a competitive procurement process approved by the PUCO (under ESP IV), PPUC (under the DSP) and MDPSC (under the SOS), respectively. If any supplier fails to deliver power to any one of those Utilities service areas, the Utility serving that area may need to procure the required power in the market in their role as the default Load Serving Entity. West Virginia electric generation continues to be regulated by the WVPSC. Fuel Supply MP currently has coal contracts with various terms to purchase approximately 7.4 million tons of coal for the year 2023, which, along with its 2022 year-end inventory levels, accounts for nearly all of its forecasted 2023 coal requirements. MP has the ability to acquire additional tonnage through options available in its current contracts, as well as purchases through the spot market. The contracts expire at various times through 2026. This contracted coal is produced primarily from mines located in Pennsylvania, Illinois and West Virginia. In order to meet emission requirements, MP holds contracts for a variety of reagents expiring at various times through 2026, as well as the ability to purchase additional reagents through the spot market. Additionally, MP is granted emission allowances by the EPA and purchases additional allowances as needed to meet emission requirements. See "Outlook - Environmental Matters" in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" for additional information pertaining to the impact of increased environmental regulations on fuel supply. System Demand The maximum hourly demand for each of the Utilities was: ##TABLE_START System Demand 2022 2021 2020 (in MWs) CEI 4,266 4,253 4,188 JCPL 6,122 5,902 6,056 ME 3,021 2,976 2,974 MP 2,124 2,114 2,121 OE 5,652 5,598 5,494 PE 3,514 2,905 3,609 Penn 944 889 946 PN 2,838 2,908 3,020 TE 2,277 2,265 2,787 WP 3,827 3,827 4,012

Ticker: FE, Sector: Utilities, Filed At: 2023-02-13T17:01:49-05:00

##TABLE_ENDRegional Reliability All of FirstEnergy's facilities are located within PJM and operate under the reliability oversight of a regional entity known as RFC. This regional entity operates under the oversight of NERC in accordance with a delegation agreement approved by FERC. Competition Within FirstEnergys Regulated Distribution segment, generally there is no competition for electric distribution service in the Utilities respective service territories in Ohio, Pennsylvania, West Virginia, Maryland, New Jersey and New York. Additionally, there has traditionally been no competition for transmission service in PJM. However, pursuant to FERCs Order No. 1000 and subject to state and local siting and permitting approvals, non-incumbent developers now can compete for certain PJM transmission projects in the service territories of FirstEnergys Regulated Transmission segment. This could result in additional competition to build transmission facilities in the Regulated Transmission segments service territories while also allowing the Regulated Transmission segment the opportunity to seek to build facilities in non-incumbent service territories. Seasonality The sale of electric power is generally a seasonal business, and weather patterns can have a material impact on FirstEnergys Regulated Distribution segment operating results. Demand for electricity in our service territories historically peaks during the summer and winter months. Accordingly, FirstEnergys annual results of operations and liquidity position may depend disproportionately on its operating performance during the summer and winter. Mild weather conditions may result in lower power sales and consequently lower revenue and earnings. Human Capital FirstEnergy focuses on a number of human capital resources, measures and objectives in managing its business, including: integrity, safety, diversity, equity and inclusion, workplace flexibility, employee development and compensation and benefits. During 2022, the company continued to enhance its dedicated focus on employees by providing employees with additional opportunities to improve belonging, inclusion and engagement within our workforce. Collectively, these focus areas may be material to understanding its business under certain circumstances. Employees and Collective Bargaining Agreements As of December 31, 2022, FirstEnergy had 12,335 employees, all of whom were located in the United States as follows: ##TABLE_START Total Employees Bargaining Unit Employees FESC 5,099 554 CEI 824 565 JCPL 1,361 1,052 ME 579 452 MP 1,080 750 OE 1,069 735 PE 501 330 Penn 173 131 PN 694 487 TE 331 253 WP 624 465 Total 12,335 5,774 ##TABLE_ENDAs of December 31, 2022, the IBEW, the UWUA and the OPEIU unions collectively represented approximately half of FirstEnergys employees. There are 15 collective bargaining agreements between FirstEnergys subsidiaries and its unions, which have three, four or five- year terms. In 2022, FirstEnergys subsidiaries reached new agreements with 3 IBEW locals, covering 620 employees, and 3 UWUA locals, covering 945 employees. Safety Safety is a core value of FirstEnergy. FirstEnergy employees have the power and responsibility to keep each other safe and eliminate life-changing events, which are injuries that have life-changing impacts or fatal results. Safety metrics, such as injuries that result in days away or restricted time and life-changing events, are regularly monitored, internally reported, and are included in our annual incentive compensation program to reinforce that a safe work environment is crucial to FirstEnergys success. FirstEnergy has shifted its focus from achieving low OSHA rates to proactively identifying and mitigating life-changing event exposure. This shift in focus strengthens FirstEnergys safety-first culture by aligning our leadership around the same goal and driving safer decisions from an engaged workforce who puts safety first. FirstEnergy continues to embed its "Leading with Safety" learnings and experiences and continues to enhance and reinforce leader and employee safety training and exposure control concepts to improve job site exposure identification, communication and mitigation to prevent life changing events. Further, FirstEnergy continues to expand its Leading with Safety experiences with its employees to achieve excellence in personal, contractor and public safety. Diversity, Equity and Inclusion DEI is a core value, as well as a corporate objective because a diverse, equitable and inclusive work environment delivers better service to customers, strong operational performance, innovation, and a safe, rewarding work experience for employees. FirstEnergy is focused on building a diverse workforce for the future, advancing a culture of equity, inclusion and belonging, and enhancing our diversity focus with our customers, in our communities and with our suppliers. Affirmative steps taken at FirstEnergy to promote the core value of diversity, equity and inclusion include: FirstEnergy sponsors an executive diversity, equity and inclusion council consisting of senior management and other leaders across the company; Recently developed FirstEnergy Utilities Operations DEI Council focused on DEI related strategy and initiatives specific to operations employees including a large represented physical work group; Holding an annual Employee Engagement Survey to capture employees perspectives on their work experience and progress toward embracing a more inclusive culture. The survey results are discussed with employees in order to drive initiatives and action plans for improvement. This includes establishing: a cross-functional working group to oversee the development and implementation of diversity, equity and inclusion action plans company-wide; additional teams of employees embedded throughout FirstEnergy to implement local actions supporting diversity, equity and inclusion; FirstEnergys employees have established multiple employee business resource groups, known as "EBRGs," to further support diversity, equity and inclusion objectives through networking, mentoring, coaching, recruiting, development and community outreach; Employees are provided ongoing training and education on a variety of diversity, equity and inclusion topics; Enhanced transparency of diversity, equity and inclusion data, talent processes and measurement of progress; FirstEnergy has enhanced the recruiting processes to increase the number of diverse candidates considered for open positions and expand the diversity of teams interviewing those candidates. These enhancements include: expanded relationship building with key diverse professional organizations, colleges and universities; a more strategic approach to proactive talent sourcing that ensures increased diversity of candidate slates presented to hiring managers; expanded diversity of teams interviewing those candidates. Increase leadership accountability by including diversity, equity and inclusion metrics in

FirstEnergys annual incentive compensation program. Workplace Flexibility FirstEnergy is committed to supporting employees work/life balance by providing flexible work arrangements for many of its employees, and encouraging career growth as well as personal balance. In Fall 2022, FirstEnergy formally adopted guidelines to facilitate flexible work arrangements for eligible full-time and part-time non-bargaining employees. Flexible work arrangements, like permitting certain employees to work from alternate locations or to begin and end work at variable times, offer a variety of approaches to the way employees work. These approaches can help employees achieve their priorities and meet customer and business needs while promoting enhanced convenience and balance between work and personal commitments. Employee Development FirstEnergys employees are empowered to take ownership of their careers with increased openness into FirstEnergys internal and external hiring process and greater availability of tools and processes that support career management, talent reviews, succession planning and leadership selection. FirstEnergy is committed to preparing its high-performing workforce for the future and helping employees reach their full potential. That means developing employee skills and competencies and preparing emerging and experienced leaders for future management responsibilities. Understanding FirstEnergys rapidly changing industry and strategy is key to employees ability to support FirstEnergys mission and meet its customers evolving needs. Key FirstEnergy development programs include: a mentoring program; new supervisor and manager program; experienced leader program; aspiring leader program; external partnership with the Center for Creative Leadership and BeingFirst for senior and executive leadership development, "Educate to Elevate," which provides access to post-secondary education and a path to both Associates and Bachelors degrees for employees; Power Systems Institute, an award-winning program for recruiting and developing the next generation of highly trained, dedicated and motivated line and substation workers; and A pilot apprentice line worker program in Ohio and Pennsylvania that was launched in 2022 and designed to address labor shortages in areas where we have had difficulty attracting talent or have experienced higher-than-average attrition rates. Compensation and Benefits FirstEnergys total rewards program is designed to attract, motivate, retain and reward employees for their role in the success of FirstEnergy. The base pay program is designed to provide individual base pay levels that balance an employees value to FirstEnergy with comparable jobs at peer companies. FirstEnergy is committed to ensuring that our internal policies and processes support pay equity, which was confirmed in a third-party review of our practices in 2019 and continues to be part of our normal ongoing process. Our internal processes ensure pay equity considerations are part of our normal ongoing process. The annual incentive compensation program is designed to reward the achievement of near-term corporate and business unit objectives. Additionally, FirstEnergys long-term incentive compensation program is designed to reward eligible executives for FirstEnergys achievement of longer-term goals intended to drive shareholder value and growth. In addition to base pay and incentive compensation plans, FirstEnergy offers a comprehensive benefits program, including a 401(k) savings plan and a defined benefit pension plan. Information About Our Executive Officers (as of February 13, 2023) ##TABLE_START Name Age Positions Held During Past Five Years Dates John W. Somerhalder II 67 Interim Chief Executive Officer (A) 2022-Present (H) Interim President (B) 2022-Present Vice Chair and Executive Director (A) 2021-2022 CenterPoint Energy Inc, Interim President Chief Executive Officer 2020 Samuel L. Belcher 54 Senior Vice President, Operations (B) 2021-Present (I) President (C) (E) 2018-Present Senior Vice President and President, FirstEnergy Utilities (B) 2018-2021 President and Chief Nuclear Officer (G) *-2018 Hyun Park 61 Senior Vice President and Chief Legal Officer (A) (B) 2021-Present Senior Vice President and General Counsel (C) (D) (E) 2021-2022 LimNexus, Partner and General Counsel 2019-2021 Latham Watkins, Of Counsel *-2019 K. Jon Taylor 49 Senior Vice President, Chief Financial Officer and Strategy (A) (B) 2021-Present Senior Vice President and Chief Financial Officer (C) (E) 2020-Present Senior Vice President and Chief Financial Officer (A) (B) 2020-2021 Vice President, Utility Operations (B) 2019-2020 President (D) 2019-2020 President, Ohio Operations (B) 2018-2019 Vice President (C) 2018-2019 Vice President and Controller (C) (E) *-2018 Vice President, Controller and Chief Accounting Officer (A) (B) *-2018 Jason J. Lisowski 41 Vice President, Controller and Chief Accounting Officer (A) (B) 2018-Present Vice President and Controller (C) (E) 2018-Present Controller and Treasurer (F) (G) *-2018 Christine L. Walker 57 Senior Vice President, Chief Human Resources Officer and Corporate Services (B) 2021-Present Senior Vice President and Chief Human Resources Officer (B) 2019-2021 Vice President, Human Resources (B) 2018-2019 Executive Director, Talent Management (B) *-2018 ##TABLE_END##TABLE_START * Indicates position held at least since January 1, 2018 (A) Denotes position held at FE (B) Denotes position held at FESC (C) Denotes position held at the Ohio Companies, the Pennsylvania Companies, MP, PE, FET, KATCo, TrAIL and ATSI (D) Denotes position held at AGC (E) Denotes position held at MAIT (F) Denotes position held at FES and FG (G) Denotes position held at FENOC (H) Also served as Chair of the FE Board from May 2022 - Present (I) On January 17, 2023, Samuel L. Belcher notified FirstEnergy of his intent to retire effective May 1, 2023 ##TABLE_ENDFirstEnergy Website and Other Social Media Sites and Applications FirstEnergy's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, amendments to those reports, and all other documents filed with or furnished to the SEC pursuant to Section 13(a) of the Exchange Act are made available free of charge on or through the "Investors" page of FirstEnergys website at www.firstenergycorp.com. These documents are also available to the public from commercial document retrieval services and the website maintained by the SEC at www.sec.gov. These SEC filings are posted on the website as soon as reasonably practicable after they are electronically filed with or furnished to the SEC. Additionally, FirstEnergy routinely posts additional important information, including press releases, investor presentations, investor factbooks and notices of upcoming events under the "Investors" section of FirstEnergys website and recognizes FirstEnergys website as a channel of distribution to reach public investors and as a means of disclosing material non-public information for complying with disclosure obligations under Regulation FD. Investors may be notified of postings to the website by signing up for email alerts and Rich Site Summary feeds on the "Investors" page of FirstEnergy's website. FirstEnergy also uses Twitter and Facebook as additional channels of distribution to reach public investors and as a supplemental means of disclosing material non-public information for complying with its disclosure obligations under Regulation FD. Information contained on FirstEnergys website, Twitter handle or Facebook page, and any corresponding applications of those sites, shall not be deemed incorporated into, or to be part of, this report. ITEM 1A. RISK FACTORS We operate in a business environment that involves significant risks, many of which are beyond our control. Management regularly evaluates the most significant risks of its businesses and reviews those risks with the FE Board and appropriate Committees of the FE Board. The following risk factors and all other information contained in this report should be considered carefully when evaluating FirstEnergy. These risk factors could affect our financial results and cause such results to differ materially from those expressed in any forward-looking statements made by or on behalf of us. Below, we have identified risks we consider material. You should not interpret the disclosure of any risk factor to imply that the risk has not already materialized. Although the risks are organized by headings, and each risk is discussed separately, many are interrelated. Additional information on risk factors is included in Item 1, "Business, Item 7, "Managements Discussion and Analysis of Financial Condition and Results of Operations, and in other sections of this Form 10-K that include forward-looking and other statements involving risks and uncertainties that could impact our business and financial results. Risks Associated with Damage to Our Reputation and HB 6 Related Litigation and Investigations Damage to our reputation may arise from numerous sources making us vulnerable to negative customer perception, adverse regulatory outcomes, or other consequences, which could materially adversely affect our business, results of operations, and financial condition. Our reputation is important. Damage to our reputation could materially adversely affect our business, results of operations, and financial condition and may arise from numerous sources further discussed below, including a breach of the DPA, negative outcomes associated with the SEC investigation or other HB 6 litigation or investigations, a significant cyber-attack or data security breach, failure to provide safe and reliable service, and operating coal-fired generation. Any damage to our reputation may lead to negative customer perception, which may make it difficult for us to compete successfully for new opportunities, or could adversely impact our ability to launch new sophisticated technology-driven solutions to meet our customer expectations. Further, a damaged reputation could further result in FERC and the state utility commissions that regulate our rates, and other regulatory and legislative authorities being less likely to view us in a favorable light, and could negatively impact the rates we charge customers or otherwise cause us to be susceptible to unfavorable legislative and regulatory outcomes, as well as increased regulatory oversight and more stringent legislative or regulatory requirements. If We Violate our DPA That We Entered Into on July 20, 2021, It Could Have a Material Adverse Effect on our Reputation and Consolidated Financial Statements On July 21, 2021, we entered into a three-year DPA with the U.S. Attorneys Office that, subject to court proceedings, resolves the previously disclosed U.S. Attorneys Office investigation into us relating to our lobbying and governmental affairs activities concerning HB 6. Under the DPA, the U.S. Attorneys Office filed a single charge alleging that we conspired to commit honest services wire fraud. The DPA provides that the U.S. Attorneys Office will defer any prosecution of such conspiracy charge and any other criminal or civil case against us in connection with the matters identified therein for a three-year period subject to certain obligations of ours, including, but not limited to, the following: (i) continued cooperation with the U.S. Attorneys Office in all matters relating to the conduct described in the DPA and other conduct under investigation by the U.S. government; (ii) payment of a criminal monetary penalty totaling $230 million, which was paid in 2021; (iii) publish a list of all payments made in 2021 to either 501(c)(4) entities or to entities known by FirstEnergy to be operating for the benefit of a public official, either directly or indirectly, and update the same on a quarterly basis during the term of the DPA; (iv) publication of a public acknowledgement of our conduct, including a statement, as dictated in the DPA, regarding our use of 501(c)(4) entities; and (v) continued implementation and review of our compliance and ethics program, internal controls, policies and procedures designed, implemented and enforced to prevent and detect violations of the U.S. laws throughout its operations, and to take certain related remedial measures. If we are found to have breached the terms of the DPA, the U.S. Attorneys Office may elect to prosecute, or bring a civil action against, us for conduct alleged in the DPA or known to the government, which could result in fines or penalties and could have a material adverse impact on our reputation or relationships with regulatory and legislative authorities, customers and other stakeholders, as well as our consolidated financial statements. Failure to comply with the DPA, including alleged failures to comply with anti-corruption and anti-bribery laws, may also result in a breach of certain covenants contained in our credit agreements and could result in an event of default under such agreements, and we would not be able to access our credit facilities for additional borrowings and letters of credit during the existence of any such default. The SEC Investigation and HB 6 Related Litigation Could Have a Material Adverse Effect on our Reputation, Business, Financial Condition, Results of Operations, Liquidity or Cash Flows Following the announcement by the U.S. Attorneys Office for the S.D. Ohio of the investigation surrounding HB 6 in July 2020, certain of our stockholders and customers filed several lawsuits against us and certain current and former directors, officers and other employees, including the federal securities class action litigation In re FirstEnergy Corp. Securities Litigation (Federal District Court, S.D. Ohio). The investigations and litigation related to HB 6 could divert managements focus and have resulted in, and could continue to result in substantial investigation expenses, and the commitment of substantial corporate resources. The outcome, duration, scope, result or related costs of the investigations and related litigation of the government investigations, particularly the SEC investigation and the securities class action lawsuit discussed below, are inherently uncertain. Therefore, any of these risks could impact us significantly beyond expectations. Moreover, we are unable to predict the potential for any additional investigations or litigation, any of which could exacerbate these risks or expose us to potential criminal or civil liabilities, sanctions or other remedial measures, and could have a material adverse effect on our reputation, business, financial condition, results of operations, liquidity or cash flows. On August 10, 2020, the SEC, through its Division of Enforcement, issued an order directing an investigation of possible securities laws violations by FirstEnergy, and on September 1, 2020, issued subpoenas to FirstEnergy and certain of its officers. We are cooperating with the SEC in their ongoing investigation. We believe that it is probable that FE will incur a loss in connection with the resolution of the SECs investigation. Given the ongoing nature and complexity of such investigation, we cannot yet reasonably estimate a loss or range of loss that may arise from the resolution of the SEC investigation, but such resolution could have a material adverse effect on our reputation, business, financial condition, results of operations, liquidity or cash flows. We also believe that it is probable that FE will incur a loss in connection with the resolution of In re FirstEnergy Corp. Securities Litigation . Given the ongoing nature and complexity of such litigation, we cannot yet reasonably estimate a loss or range of loss that may arise from its resolution. However, if it is resolved against us substantial monetary damages could result and our reputation, business, financial condition, results of operations, liquidity or cash flows may be materially adversely affected. These matters are likely to continue to have an adverse impact on the trading prices of our securities. See Note 13, Commitments, Guarantees and Contingencies, of the Notes to Consolidated Financial Statements, for additional details on the government investigations and subsequent litigation surrounding HB 6. The HB 6 Related State Regulatory Investigations Could Have a Material Adverse Effect on our Reputation, Business, Financial Condition, Results of Operations, Liquidity or Cash Flows There are several state regulatory matters associated with the ongoing governmental investigations including, but not limited to, the following: On August 16, 2022, the U.S. Attorney for the Southern District of Ohio requested that the PUCO stay the following pending HB 6 related matters for a period of six months, which request was granted by the PUCO on August 24, 2022: On September 15, 2020, the PUCO opened a new proceeding to review the political and charitable spending by the Ohio Companies in support of HB 6 and the subsequent referendum effort. On November 4, 2020, the PUCO initiated an additional corporate separation audit as a result of the FirstEnergy leadership transition announcement made on October 29, 2020 On December 30, 2020, the PUCO directed PUCO staff to solicit a third-party auditor and conduct a full review of the DMR to ensure funds collected from customers through the DMR were only used for the purposes established in ESP IV. The auditors report was filed on January 14, 2022 and the parties submitted final comments and responses in the second quarter 2022. See Outlook Ohio below for additional information regarding the auditors findings. On

March 10, 2021, the PUCO expanded the scope of an ongoing annual audit of the Ohio Companies Rider DCR for 2020 to include a review of certain transactions that were either improperly classified, misallocated, or lacked supporting documentation, and to determine whether funds collected from customers were used to pay the vendors, and if so, whether or not the funds associated with those payments should be returned to customers through Rider DCR or through an alternative proceeding. On May 11, 2021, the Maryland Office of Peoples Counsel filed a petition asking the MDPSC to open an investigation regarding several matters including possible impacts to PE as a result of the HB 6 investigations in Ohio. On July 26, 2021, the MDPSC opened a proceeding to allow discovery into: (i) whether the HB 6 investigations in Ohio have impacted or could impact the cost to PE of borrowing funds from the regulated companies money pool; (ii) whether money from PE was used to pay for bribes or other misconduct associated with the HB 6 investigations in Ohio or the legal costs related to those matters; and (iii) whether the Icahn Capital appointed directors would have the ability to assert substantial influence over PE in their roles as FE directors. While FirstEnergy is committed to pursuing an open dialogue with stakeholders in an appropriate manner with respect to the numerous regulatory proceedings currently underway, the rates our Utilities and Transmission Companies are allowed to charge may be decreased as a result of actions taken by a regulator to which our Utilities and Transmission Companies are subject to jurisdiction, whether as a result of the DPA, any failure to have complied with anti-corruption laws, or otherwise. We are unable to predict the adverse impacts on such regulatory matters, including with respect to rates, and, therefore, any of these risks could impact us significantly beyond expectations. Moreover, we are unable to predict the potential for any additional regulatory actions, any of which could exacerbate these risks or expose us to adverse outcomes in pending or future rate cases, and could have a material adverse effect on our reputation, business, financial condition, results of operations, liquidity or cash flows. Risks Associated with the Execution of Recently Announced Strategic Initiatives The Inability to Close the FET Minority Equity Interest Sale to Brookfield Announced in February 2023 May Have Material Adverse Effects on Our Cash Flows, Liquidity and Financial Condition As previously disclosed, on November 6, 2021, FirstEnergy, along with FET, entered into the FET PSA I, with Brookfield and Brookfield Guarantors pursuant to which FET agreed to issue and sell to Brookfield at the closing, and Brookfield agreed to purchase from FET, certain newly issued membership interests of FET, such that Brookfield would own 19.9% of the issued and outstanding membership interests of FET, for a purchase price of $2.375 billion. The transaction closed on May 31, 2022. On February 2, 2023, FE, along with FET, entered into the FET PSA II with Brookfield and the Brookfield Guarantors, pursuant to which FE agreed to sell to Brookfield at the closing, and Brookfield agreed to purchase from FE, an incremental 30% equity interest in FET for a purchase price of $3.5 billion. The purchase price will be payable in part by the issuance of a promissory note expected to be in the principal amount of $1.75 billion. The remaining $1.75 billion of the purchase price will be payable in cash at the closing. As a result of the consummation of the transaction, Brookfields interest in FET will increase from 19.9% to 49.9%, while FE will retain the remaining 50.1% ownership interests of FET. The transaction is subject to customary closing conditions, including approval from the FERC and certain state utility commissions, and completion of review by the CFIUS. In addition, pursuant to the FET PSA II, FirstEnergy has agreed to make the necessary filings with the applicable regulatory authorities for the PA Consolidation. The FET Minority Equity Interest Sale is expected to close by early 2024. Upon closing, FET will continue to be consolidated in FirstEnergys GAAP financial statements. This transaction involves various inherent risks, such as our ability to obtain the necessary regulatory and third-party approvals; the timing of and conditions imposed upon us by regulators in connection with such approvals; and our ability to realize the benefits expected from the transaction. In addition, various factors, including prevailing market conditions, could negatively impact the benefits we receive from this transaction. Our failure to consummate this transaction in a timely manner, including satisfying all closing conditions, could have material adverse effects on our cash flows, liquidity and financial condition. The Consolidation of our Pennsylvania Companies May Not be Completed in a Timely Manner or at All, We May Not Be Able to Obtain the Approvals Required to Complete the PA Consolidation or Such Approvals May Contain Material Restrictions or Conditions Which May Make It Undesirable to Complete the PA Consolidation, and We Could Face Litigation Concerning the PA Consolidation, Whether or Not the PA Consolidation is Consummated The PA Consolidation, including applicable asset sales is subject to numerous conditions, including the approval of NYPSC, PPUC and FERC, which may not approve one or more of the contemplated steps in the PA Consolidation, or such approvals may impose conditions on the completion, or require changes to the terms of the PA Consolidation, including restrictions on the business, operations or financial performance of the resulting operating company, which could be adverse to FirstEnergys interests. These conditions or changes could also delay or increase the cost of the PA Consolidation or limit the net income or financial prospects of the resulting operating company. Our inability to complete the PA Consolidation in a timely manner, or at all, including applicable asset sales, could hinder our ability to close the FET Minority Equity Interest Sale to Brookfield and could negatively affect our share price, as well as our future business and financial results. In addition, the work required to complete the PA Consolidation may place a significant burden on management and internal resources. Management's attention and other company resources may be focused on the PA Consolidation instead of on day-to-day management activities, including pursuing other opportunities beneficial to FirstEnergy. Risks Associated with Regulation of Our Distribution and Transmission Segments We are Focusing on Growing Our Regulated Distribution and Regulated Transmission Segments. Whether This Investment Strategy Will Deliver the Desired Result Is Subject to Certain Risks Which Could Adversely Affect Our Results of Operations and Financial Condition We focus on capitalizing on investment opportunities available to our Regulated Transmission and Regulated Distribution segments as we focus on delivering enhanced customer service and reliability. The success of these efforts will depend, in part, on successful recovery of our transmission investments. Factors that may affect rate recovery of our transmission investments include: (1) FERCs timely approval of rates to recover such investments; (2) whether the investments are included in PJM's Regional Transmission Expansion Plan; (3) FERC's evolving policies with respect to incentive rates for transmission assets; (4) FERC's evolving policies with respect to the calculation of the base ROE component of transmission rates; (5) consideration and potential impact of the objections of those who oppose such investments and their recovery; and (6) timely development, construction, and operation of the new facilities. The success of these efforts will also depend, in part, on any future distribution rate cases or other filings seeking cost recovery for distribution system enhancements in the states where our Utilities operate and transmission rate filings at FERC. Any denial of, or delay in, the approval of any future distribution or transmission rate requests could restrict us from fully recovering our cost of service, may impose risks on the Regulated Distribution and Regulated Transmission operations, and could have a material adverse effect on our regulatory strategy, results of operations and financial condition. Our efforts also could be impacted by our ability to finance the proposed expansion projects while maintaining adequate liquidity. There can be no assurance that our investment strategy in our Regulated Distribution and Regulated Transmission segments will deliver the desired result which could adversely affect our results of operations and financial condition. Complex and Changing Government Regulations and Actions, Including Those Associated with Rates, Could Have a Negative Impact on Our Business, Financial Condition, Results of Operations and Cash Flows We are subject to comprehensive regulation by various federal, state and local regulatory agencies that significantly influence our operating environment. Changes in, or reinterpretations of, existing laws or regulations, or the imposition of new laws or regulations, could require us to incur additional costs or change the way we conduct our business, and therefore could have a material adverse impact on our results of operations and financial condition. Our Utilities and Transmission Companies provide service at rates approved by one or more regulatory commissions. Thus, the rates the Utilities and Transmission Companies are allowed to charge may be decreased as a result of actions taken by FERC or by a state regulatory commission in the states in which our Utilities operate. Also, these rates may not be set to recover such applicable utility's expenses at any given time. Additionally, there may also be a delay between the timing of when costs are incurred and when costs are recovered, if at all. For example, we may be unable to timely recover the costs for our energy efficiency investments or expenses and additional capital or lost revenues resulting from the implementation of aggressive energy efficiency programs. While rate regulation is premised on providing an opportunity to earn a reasonable return on investments and recovery of operating expenses, there can be no assurance that the applicable regulatory commission will determine that all of our costs have been prudently incurred or that the regulatory process in which rates are determined will always result in rates that will produce full recovery of our costs in a timely manner. Further, there can be no assurance that we will retain the expected recovery in future rate cases. State Rate Regulation May Delay or Deny Full Recovery of Costs and Impose Risks on Our Operations. Any Denial of or Delay in Cost Recovery Could Have an Adverse Effect on Our Business, Results of Operations, Liquidity, Cash Flows and Financial Condition Each of the Utilities' retail rates are set by its respective regulatory agency for utilities in the state in which it operates - in Maryland by the MDPSC, in New Jersey by the NJBPU, in Ohio by the PUCO, in Pennsylvania by the PPUC, in West Virginia by the WVPSC and in New York by the NYPSC - through traditional, cost-based regulated utility ratemaking. As a result, any of the Utilities may not be permitted to recover its costs and, even if it is able to do so, there may be a significant delay between the time it incurs such costs and the time it is allowed to recover them. Factors that may affect outcomes in the distribution rate cases include: (i) the value of plant in service; (ii) authorized rate of return; (iii) capital structure (including hypothetical capital structures); (iv) depreciation rates; (v) the allocation of shared costs, including consolidated deferred income taxes and income taxes payable across the Utilities; (vi) regulatory approval of rate recovery mechanisms for capital investment spending programs; and (vii) the accuracy of forecasts used for ratemaking purposes in "future test year" cases. FirstEnergy can provide no assurance that any base rate request filed by any of the Utilities will be granted in whole or in part. Any denial of, or delay in, any base rate request could restrict the applicable utility from fully recovering its costs of service, may impose risks on its operations, and may negatively impact its results of operations, cash flows and financial condition. In addition, to the extent that any of the Utilities seeks rate increases after an extended period of frozen or capped rates, pressure may be exerted on the applicable legislators and regulators to take steps to control rate increases, including through some form of rate increase moderation, reduction or freeze. Any related public discourse and debate can increase uncertainty associated with the regulatory process, the level of rates and revenues that are ultimately obtained, and the ability of the Utility to recover costs. Such uncertainty may restrict operational flexibility and resources, reduce liquidity and increase financing costs. Federal Rate Regulation May Delay or Deny Full Recovery of Costs and Impose Risks on Our Operations. Any Denial or Reduction of, or Delay in Cost Recovery Could Have an Adverse Effect on Our Business, Results of Operations, Cash Flows and Financial Condition FERC policy currently permits recovery of prudently incurred costs associated with cost-of-service-based wholesale power rates and the expansion and updating of transmission infrastructure within its jurisdiction. FERCs policies on recovery of transmission costs continue to evolve, evidenced by ongoing proceedings to determine an appropriate ROE methodology to determine transmission ROEs, and to determine whether FERCs existing policies on transmission rate incentives should be revised. If FERC were to adopt a different policy regarding recovery of transmission costs or if there is any resulting delay in cost recovery, our strategy of investing in transmission could be affected. If FERC were to lower the rate of return it has authorized for FirstEnergy's cost-based wholesale power rates or transmission investments and facilities, it could reduce future earnings and cash flows, and adversely impact our financial condition. We Could be Subject to Higher Costs and/or Penalties Related to Mandatory Reliability Standards Set by NERC/FERC or Changes in the Rules of Organized Markets, Which Could Have an Adverse Effect on our Financial Condition Owners, operators, and users of the bulk electric system are subject to mandatory reliability standards promulgated by NERC and approved by FERC. The standards are based on the functions that need to be performed to ensure that the bulk electric system operates reliably. NERC, RFC and FERC can be expected to continue to refine existing reliability standards as well as develop and adopt new reliability standards. Compliance with modified or new reliability standards may subject us to higher operating costs and/or increased investments. If we were found not to be in compliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties. FERC has authority to impose penalties up to and including $1.5 million per day for failure to comply with these mandatory electric reliability standards. In addition to direct regulation by FERC, we are also subject to rules and terms of participation imposed and administered by various RTOs and ISOs that can have a material adverse impact on our business. For example, the independent market monitors of ISOs and RTOs may impose bidding and scheduling rules to curb the perceived potential for exercise of market power and to ensure the markets function appropriately. Such actions may materially affect our ability to sell, and the price we receive for, our energy and capacity. In addition, PJM may direct our transmission-owning affiliates to build new transmission facilities to meet PJM's reliability requirements or to provide new or expanded transmission service under the PJM Tariff. We may be allocated a portion of the cost of transmission facilities built by others due to changes in RTO transmission rate design. We may be required to expand our transmission system according to decisions made by an RTO rather than our own internal planning processes. Various proposals and proceedings before FERC may cause transmission rates to change from time to time. In addition, RTOs have been developing rules associated with the allocation and methodology of assigning costs associated with improved transmission reliability, reduced transmission congestion and firm transmission rights that may have a financial impact on us. As a member of PJM, which is an RTO, we are subject to certain additional risks, including those associated with the allocation among members of losses caused by unreimbursed defaults of other participants in PJMs market and those associated with complaint cases filed against PJM that may seek refunds of revenues previously earned by its members. Risks Related to Business Operations Generally Temperature Variations as Well as Severe Weather Conditions or Other Natural Disasters Could Have an Adverse Impact on Our Results of Operations and Financial Condition Weather conditions directly influence the demand for electric power. Demand for power generally peaks during the summer and winter months, with market prices also typically peaking at that time. Overall operating results may fluctuate based on weather conditions. In addition, we have historically sold less power, and consequently received less revenue, when seasonal weather conditions are milder. In addition, severe weather, such as tornadoes, hurricanes, ice or snowstorms, droughts, high winds or other natural disasters, may cause outages and property damage that may require us to incur additional costs that are generally not insured and that may not be recoverable from customers. The effect of the failure of our facilities to operate as planned under these conditions would be particularly burdensome during a peak demand period and could have an adverse effect on our financial condition and results of operations, which adverse effects could be further exacerbated by an increased frequency of such severe weather events. Cyber-Attacks, Data Security Breaches and Other Disruptions to Our Information Technology Systems, or Those of Third Parties We Do Business With, Could Compromise Our Business Operations, Critical and Proprietary Information and Employee and Customer Data, Which Could Have a Material Adverse Effect on Our Business, Results of Operations, Financial Condition and Reputation In the ordinary course of our business, we depend on information technology systems that utilize sophisticated operational systems and network infrastructure to run all facets of our regulated generation, transmission and distribution services. Additionally, we store sensitive data, intellectual property and proprietary or personally identifiable information regarding our business, employees, shareholders, customers, suppliers, business partners and other individuals in our data centers and on our networks. We may also need to provide sensitive data to vendors and service providers who require access to this information. The secure maintenance of information and information technology systems is critical to our operations. Over the last several years, there has been an increase in the frequency of cyber-attacks by terrorists, hackers, international activist organizations, countries and individuals. These and other unauthorized parties may attempt to gain access to our network systems or facilities, or those of third parties with whom we do business in many ways, including directly through our network infrastructure or through fraud, trickery, or other forms of deceiving our employees, contractors and temporary staff. Additionally, our information and information technology systems and those of our vendors and service providers may be increasingly vulnerable to data security breaches, damage and/or interruption due to viruses, human error, malfeasance, faulty password management or other malfunctions and disruptions. Further, hardware, software, or applications we develop or procure from third parties may contain defects in design or manufacture or other problems that could unexpectedly compromise information and/or security. Despite security measures and safeguards we have employed, including certain measures implemented pursuant to mandatory NERC Critical Infrastructure Protection standards, our infrastructure may be increasingly vulnerable to such attacks as a result of the rapidly evolving and increasingly sophisticated means by which attempts to defeat our security measures and gain access to our information technology systems may be made. Also, we may be at an increased risk of a cyber-attack and/or data security breach due to the nature of our business. Any such cyber-attack, data security breach, damage, interruption and/or defect could: (i) disable our generation, transmission (including our interconnected regional transmission grid) and/or distribution services for a significant period of time; (ii) delay development and construction of new facilities or capital improvement projects; (iii) adversely affect our customer operations; (iv) corrupt data; and/or (v) result in unauthorized access to the information stored in our data centers and on our networks and those of our vendors and service providers, including, company proprietary information, supplier information, employee data, and personal customer data, causing the information to be publicly disclosed, lost or stolen or result in incidents that could result in economic loss and liability and harmful effects on the environment and human health, including loss of life. Additionally, because our regulated generation, transmission and distribution services are part of an interconnected system, disruption caused by a cybersecurity incident at another utility, electric generator, RTO, or commodity supplier could also adversely affect our operations. Although we maintain cyber insurance and property and casualty insurance, there can be no assurance that liabilities or losses we may incur, including as a result of cybersecurity-related litigation, will be covered under such policies or that the amount of insurance will be adequate. Further, as cyber threats become more difficult to detect and successfully defend against, there can be no assurance that we can implement adequate preventive measures, accurately assess the likelihood of a cyber-incident or quantify potential liabilities or losses. Also, we may not discover any data security breach and loss of information for a significant period of time after the data security breach occurs particularly those of our vendors and service providers. For all of these reasons, any such cyber incident could result in significant lost revenue, the inability to conduct critical business functions and serve customers for a significant period of time, the use of significant management resources, legal claims or proceedings, regulatory penalties, significant remediation costs, increased regulation, increased capital costs, increased protection costs for enhanced cybersecurity systems or personnel, damage to our reputation and/or the rendering of our internal controls ineffective, all of which could materially adversely affect our business, results of operations, financial condition and reputation. If Our "FE Forward" Initiative and Other Cost Saving Initiatives Do Not Achieve the Expected Benefits, There Could Be Negative Impacts to FirstEnergy's Business, Results of Operations and Financial Condition In February 2021, we announced a new initiative, FE Forward, to build upon our strong operations and business fundamentals and deliver immediate value and resilience, with targeted working capital improvements by 2022 and capital efficiencies ramping up through 2024 that would be redeployed in a more diverse capital investment program. In the two years that FE Forward has been active, we have realized working capital improvements and annualized capital expenditure efficiencies in line with our previously disclosed expectations. After assessing our accomplishments and shortfalls, FE Forward has been integrated into our ongoing efforts for continuous improvement, including the strategic reduction of operating expenditures and continued reinvestment in a more diverse capital program in support of our long-term strategy. As such, FirstEnergy has transitioned away from measuring these cash flow metrics and will no longer publish a forecast of these metrics. In addition to FE Forward, FirstEnergy will leverage other opportunities to reduce costs such as filling only critical positions, implementing our facility optimization plans, as well as exploring other additional, sustainable opportunities, such as reducing contractor spend. There can be no assurance that FE Forward and our other cost saving initiatives will provide the anticipated benefits to our business, results of operations and financial condition in a timely manner, if at all. Our ability to achieve the benefits from FE Forward and our other cost saving initiatives is subject to many estimates and assumptions. FirstEnergy could experience unexpected delays and business disruptions resulting from supporting these initiatives, decreased productivity, and higher than anticipated costs, any of which may impair our ability to reduce operating expenditures and to achieve anticipated results or otherwise harm FirstEnergy's business, results of operations and financial condition. Inflation may negatively impact our financial condition, results of operations, liquidity, and cash flows. Prices for equipment, materials, supplies, employee labor contractor services, together with the cost of variable-rate debt have increased during 2022, and could continue to increase in 2023 and beyond. Long-term inflationary pressures may result in such prices continuing to increase more quickly than expected. Inflation increases costs for labor, materials and services, and we may be unable to secure these resources on economically acceptable terms or offset such costs with increased revenues, operating efficiencies, or cost savings, which may adversely impact our financial condition, results of operations, liquidity, and cash flows. Continued Supply Chain Disruptions Could Have an Adverse Effect on Our Results of Operations, Cash Flow and Financial Condition. We have continued to experience supply chain challenges due to economic conditions that have developed since the start of the COVID-19 pandemic, with order lead times increasing across numerous material categories and with some as much as doubling from pre-pandemic lead times. Some key suppliers have struggled with labor shortages and raw material availability, which along with increasing inflationary pressure, have increased the costs and decreased the availability of certain materials, equipment and contractors. FirstEnergy has taken steps to mitigate these risks and does not currently expect service disruptions or any material impact on its capital spending plan. However, the situation remains fluid and a prolonged continuation or further increase in supply chain disruptions could have an adverse effect on FirstEnergys results of operations, cash flow and financial condition. We Are Subject to Financial Performance Risks from Regional and General Economic Cycles as Well as Heavy Industries such as Shale Gas, Automotive and Steel Our business follows economic cycles. Economic conditions, including inflationary pressures, impact the demand for electricity and declines in the demand for electricity will reduce our revenues. The regional economy in which our Utilities operate is influenced by conditions in industries in our business territories, e.g., shale gas, automotive, chemical, steel and other heavy industries, and as these conditions change, our revenues will be impacted. We Are Subject to Risks Arising from the Operation of Our Power Plants and Transmission and Distribution Equipment Which Could Reduce Revenues, Increase Expenses and Have a Material Adverse Effect on Our Business, Financial Condition and Results of Operations

Operation of generation, transmission and distribution facilities involves risk, including the risk of potential breakdown or failure of equipment or processes due to aging infrastructure, fuel supply or transportation disruptions, accidents, labor disputes or work stoppages by employees, human error in operations or maintenance, acts of terrorism or sabotage, construction delays or cost overruns, shortages of or delays in obtaining equipment, material and labor, operational restrictions resulting from environmental requirements and governmental interventions, and performance below expected levels. In addition, weather-related incidents and other natural disasters can disrupt generation, transmission and distribution delivery systems. Because our transmission facilities are interconnected with those of third parties, the operation of our facilities could be adversely affected by unexpected or uncontrollable events occurring on the systems of such third parties. Capital Investments and Construction Projects May Not be Completed Within Forecasted Budget, Schedule or Scope Parameters or Could be Canceled Which Could Adversely Affect Our Business and Results of Operations Our business plan calls for extensive capital investments totaling approximately $18 billion from 2021 through 2025, including but not limited to our Energizing the Future transmission expansion program and our distribution grid modernization, resiliency and reliability programs. We may be exposed to the risk of substantial price increases in, or the adequacy or availability of, the costs of labor and materials used in construction, nonperformance of equipment and increased costs due to inflation, delays, including delays relating to the procurement of permits or approvals, adverse weather or environmental matters. We engage numerous contractors and enter into a large number of construction agreements to acquire the necessary materials and/or obtain the required construction-related services. As a result, we are also exposed to the risk that these contractors and other counterparties could breach their obligations to us. Such risk could include our contractors inabilities to procure sufficient skilled labor as well as potential work stoppages by that labor force. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements at then-current market prices that may exceed our contractual prices, with resulting delays in those and other projects. Although our agreements are designed to mitigate the consequences of a potential default by the counterparty, our actual exposure may be greater than these mitigation provisions. Also, because we enter into construction agreements for the necessary materials and to obtain the required construction related services, any cancellation by FirstEnergy of a construction agreement could result in significant termination payments or penalties. Any delays, increased costs or losses, or cancellation of a construction project could adversely affect our business and results of operations, particularly if we are not permitted to recover any such costs in rates. Physical Acts of War, Terrorism. Sabotage or Other Attacks on any of Our Facilities or Other Infrastructure Could Have an Adverse Effect on Our Business, Results of Operations, Cash Flows and Financial Condition As a result of the continued threat of physical acts of war, terrorism, sabotage or other attacks in the United States, our electric generation, fuel storage, transmission and distribution facilities and other infrastructure, including power plants, transformer and high voltage lines and substations, or the facilities or other infrastructure of an interconnected company, could be direct targets of, or indirect casualties of, an act of war, terrorism, sabotage or other attack, which could result in disruption of our ability to generate, purchase, transmit or distribute electricity for a significant period of time, otherwise disrupt our customer operations and/or result in incidents that could result in harmful effects on the environment and human health, including loss of life. Any such disruption or incident could result in a significant decrease in revenue, significant additional capital and operating costs, including costs to implement additional security systems or personnel to purchase electricity and to replace or repair our assets over and above any available insurance reimbursement, higher insurance deductibles, higher premiums and more restrictive insurance policies, legal claims or proceedings, greater regulation with higher attendant costs, generally, and significant damage to our reputation, which could have a material adverse effect on our business, results of operations, cash flows and financial condition. Failure to Provide Safe and Reliable Service and Equipment Could Result in Serious Injury or Loss of Life That May Harm Our Business Reputation and Adversely Affect Our Operating Results We are committed to providing safe and reliable service and equipment in our franchised service territories. Meeting this commitment requires the expenditure of significant capital resources. However, our employees, contractors and the general public may be exposed to dangerous environments due to the nature of our operations. Failure to provide safe and reliable service and equipment due to various factors, including equipment failure, accidents and weather, could result in serious injury or loss of life that may harm our business reputation and adversely affect our operating results through reduced revenues, increased capital and operating costs, litigation or the imposition of penalties/fines or other adverse regulatory outcomes. The Outcome of Litigation, Arbitration, Mediation, and Similar Proceedings Involving Our Business, or That of One or More of Our Operating Subsidiaries, Is Unpredictable and an Adverse Decision in Any Material Proceeding Could Have a Material Adverse Effect on Our Financial Condition and Results of Operations We are involved in a number of litigation, arbitration, mediation, and similar proceedings. These and other matters may divert financial and management resources that would otherwise be used to benefit our operations. Further, no assurances can be given that the resolution of these matters will be favorable to us. If certain matters were ultimately resolved unfavorably to us, the results of operations and financial condition of FirstEnergy could be materially adversely impacted. In addition, we are sometimes subject to investigations and inquiries by various state and federal regulators due to the heavily regulated nature of our industry. Any material inquiry or investigation could potentially result in an adverse ruling against us, which could have a material adverse impact on our financial condition and operating results. We Face Certain Human Resource Risks Associated with Potential Labor Disruptions and/or with the Availability of Trained and Qualified Labor to Meet Our Future Staffing Requirements We are continually challenged to find ways to balance the retention of our aging skilled workforce while recruiting new talent to mitigate losses in critical knowledge and skills due to retirements. Workforce demographic issues challenge employers nationwide and are of particular concern to the electric utility industry. Over the next three years, 34% percent of our current employees will meet the eligibility requirements to retire. Our costs, including costs for contractors to replace employees and productivity costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, may adversely affect our ability to manage and operate our business. If we are unable to successfully recruit and retain an appropriately qualified workforce, our results of operations could be negatively affected. Additionally, a significant number of our physical workforce are represented by unions. While we believe that our relations with our employees are generally fair, we cannot provide assurances that the company will be completely free of labor disruptions such as work stoppages, work slowdowns, union organizing campaigns, strikes, lockouts or that any labor disruption will be favorably resolved. Mitigating these risks could require additional financial commitments and the failure to prevent labor disruptions and retain and/or attract trained and qualified labor could have an adverse effect on our business. Significant Increases in Our Operation and Maintenance Expenses, Including Our Health Care and Pension Costs, Could Adversely Affect Our Future Earnings and Liquidity We continually focus on limiting and reducing where possible, our operation and maintenance expenses. However, we expect to continue to face increased cost pressures related to operation and maintenance expenses, including in the areas of health care and pension costs. We have experienced health care cost inflation in recent years, and we expect our cash outlay for health care costs, including prescription drug coverage, to continue to increase despite measures that we have taken requiring employees and retirees to bear a higher portion of the costs of their health care benefits. The measurement of our expected future health care and pension obligations and costs is highly dependent on a variety of assumptions, many of which relate to factors beyond our control. These assumptions include investment returns, interest rates, discount rates, health care cost trends, benefit design changes, salary increases, the demographics of plan participants and regulatory requirements. While we anticipate that our operation and maintenance expenses will continue to increase, if actual results differ materially from our assumptions, our costs could be significantly higher than expected which could adversely affect our results of operations, financial condition and liquidity. Changes in Technology and Regulatory Policies May Make Our Facilities Significantly Less Competitive and Adversely Affect Our Results of Operations Traditionally, electricity is generated at large, central station generation facilities. This method results in economies of scale and lower unit costs than newer generation technologies such as fuel cells, microturbines, windmills and photovoltaic solar cells. It is possible that advances in newer generation technologies will make newer generation technologies more cost-effective, or that legislation addressing climate change at the federal or state level together with changes in regulatory policy will create incentives or benefits that otherwise make these newer generation technologies even more competitive with central station electricity production. To the extent that newer generation technologies are connected directly to load, bypassing the transmission and distribution systems, potential impacts could include decreased transmission and distribution revenues, stranded assets and increased uncertainty in load forecasting and integrated resource planning and could adversely affect our business and results of operations. Energy Companies are Subject to Adverse Publicity Causing Less Favorable Regulatory and Legislative Outcomes Which Could Have an Adverse Impact on Our Business Energy companies, including the Utilities and Transmission Companies, have been the subject of criticism on matters including the reliability of their distribution services and the speed with which they are able to respond to power outages, such as those caused by storm damage. Adverse publicity of this nature, as well as negative publicity associated with the operation of coal-fired generation or proceedings seeking regulatory recoveries may cause less favorable legislative and regulatory outcomes and damage our reputation, which could have an adverse impact on our business. Risks Associated with Environmental Matters We Have Coal-Fired Generation Capacity, Which Exposes Us to Risk from Regulations Relating to Coal, GHGs and CCRs and Could Lead to Increased Costs or the Need to Spend Significant Resources to Defend Allegations of Violation Historically, coal-fired generation has greater exposure to the costs of complying with federal, state and local environmental statutes, rules and regulations relating to air emissions, including GHGs and CCR disposal, than other types of electric generation facilities. These legal requirements and any future initiatives could impose substantial additional costs and, in the case of GHG requirements, could raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing electric generation facilities and could require our coal-fired generation to curtail generation or cease to generate. Failure to comply with any such existing or future legal requirements may also result in the assessment of fines and penalties. Significant resources also may be expended to defend against allegations of violations of any such requirements. We Have a Minority Ownership Stake in a Coal Mine That Requires Governmental Permits and Approvals to Operate and a Failure of the Coal Mine to Renew and Maintain Such Permits and Approvals May Adversely Affect Our Results of Operations and Cash Flow FEV currently holds a 33-1/3% equity ownership in Global Holding, the holding company for a joint venture in the Signal Peak mining and coal transportation operations with coal sales predominantly in international markets. The viability of our investment depends upon several factors beyond our control, including, but not limited to: Signal Peaks ability to renew and maintain governmental permits and approvals and remain in compliance with federal, state, and local safety and environmental statutes, rules, and regulations affecting the coal mining industry. Failure by Signal Peak to renew and maintain necessary permits and approvals, and to comply with any such statutes, rules and regulations, may impair its operations and the ability to generate cash flows necessary for Global Holding to pay future dividends and contribute to FirstEnergys earnings. Signal Peak operates a single underground coal mine in south-central

Montana and must obtain numerous governmental permits and approvals that impose strict conditions and obligations relating to, among other things, various environmental and safety matters in connection with its mining and coal transportation operations. The rules applicable to these permits and approvals are complex and can change over time. Regulatory authorities exercise considerable discretion in the timing and scope of permit issuance. In addition, the public has the right to comment on permit applications and otherwise participate in the permitting process, including through court intervention. Limitations on Signal Peaks ability to conduct its mining operations due to its inability to obtain or renew necessary permits or similar approvals could materially reduce or even halt production at the mine resulting in an adverse effect on our balance sheet, results of operations and cash flow. Signal Peak is currently a party to litigation that is challenging the validity of its permit to expand its mine into adjacent leased federal coal reserves. After receiving initial approval in 2015 from the OSMRE to expand the mine, environmental non-governmental organizations filed suit in the United States District Court for the District of Montana the same year challenging OSMREs environmental assessment, which was a finding of no significant impact, and the expansion approval. The District Court affirmed OSMREs conclusions, and the environmental non-governmental organizations appealed to the U.S. Court of Appeals for the Ninth Circuit. In April 2022, the Ninth Circuit Court reversed the District Courts ruling affirming the expansion approval and remanded the case back to the District Court. On February 10, 2023, the District Court vacated the permit issued by OSMRE, which would restrict Signal Peaks ability to mine federal coal until OSMRE completes an environmental impact statement and reissues the permit. While the District Courts ruling is not expected to materially impede Signal Peaks ability to conduct its mining operations over the next 12-24 months, the inability to successfully obtain the permit from OSMRE would prohibit Signal Peak from mining those adjacent leased federal coal reserves and could further adversely impact Signal Peak from efficiently and economically conducting its mining operations thus reducing its production, cash flow and profitability. Costs of Compliance with Environmental Laws are Significant, and the Cost of Compliance with New Environmental Laws, Including Limitations on GHG Emissions Related to Climate Change, Could Adversely Affect Our Cash Flows and Financial Condition Our operations are subject to extensive federal, state and local environmental statutes, rules and regulations. Compliance with these legal requirements requires us to incur costs for, among other things, installation and operation of pollution control equipment, emissions monitoring and fees, remediation and permitting at our facilities. These expenditures have been significant in the past and may increase in the future. We may be forced to shut down other facilities or change their operating status, either temporarily or permanently, if we are unable to comply with these or other existing or new environmental requirements, or if the expenditures required to comply with such requirements are unreasonable. Moreover, new environmental laws or regulations including, but not limited to GHG Emissions, CWA effluent limitations imposing more stringent water discharge regulations, or other changes to existing environmental laws or regulations may materially increase our costs of compliance or accelerate the timing of capital expenditures or other capital-like investments. Our compliance strategy, including but not limited to, our assumptions regarding estimated compliance costs, although reasonably based on available information, may not successfully address future relevant standards and interpretations. If we fail to comply with environmental laws and regulations or new interpretations of longstanding requirements, even if caused by factors beyond our control, that failure could result in the assessment of civil or criminal liability and fines. In addition, any alleged violation of environmental laws and regulations may require us to expend significant resources to defend against any such alleged violations. Due to the uncertainty of control technologies available to reduce GHG emissions, any legal obligation that requires substantial reductions of GHG emissions could result in substantial additional costs, adversely affecting cash flows and profitability, and raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing electric generation facilities. The EPA is Conducting NSR Investigations at Generating Plants that We Currently or Formerly Owned, Which Could Result in the Imposition of Fines We may be subject to risks from changing or conflicting interpretations of existing laws and regulations, including, for example, the applicability of the EPA's NSR programs. Under the CAA, modification of our existing and former generation facilities in a manner that results in increased emissions could subject our existing generation facilities to the far more stringent new source standards applicable to new generation facilities. The EPA has taken the view that many companies, including many energy producers, have been modifying emissions sources in violation of NSR standards during work considered by the companies to be routine maintenance. The EPA has investigated alleged violations of the NSR standards at certain of our existing and former generating facilities. We intend to vigorously pursue and defend our position, but we are unable to predict their outcomes, which could include the possible imposition of fines. We Are or May Be Subject to Environmental Liabilities, Including Costs of Remediation of Environmental Contamination at Current or Formerly Owned Facilities, Which Could Have a Material Adverse Effect on Our Results of Operations and Financial Condition We may be subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned or operated by us and of property contaminated by hazardous substances that we may have generated regardless of whether the liabilities arose before, during or after the time we owned or operated the facilities. We are currently involved in a number of proceedings relating to sites where hazardous substances have been released and we may be subject to additional proceedings in the future. We also have current or previous ownership interests in sites associated with the production of gas and the production and delivery of electricity for which we may be liable for additional costs related to investigation, remediation and monitoring of these sites. Remediation activities associated with our former MGP operations are one source of such costs. Citizen groups or others may bring litigation over environmental issues including claims of various types, such as property damage, personal injury, and citizen challenges to compliance decisions on the enforcement of environmental requirements, such as opacity and other air quality standards, which could subject us to penalties, injunctive relief and the cost of litigation. We cannot predict the amount and timing of all future expenditures (including the potential or magnitude of fines or penalties) related to such environmental matters, although we expect that they could be material. In addition, there can be no assurance that any liabilities, losses or expenditures we may incur related to such environmental liabilities or contamination will be covered under any applicable insurance policies or that the amount of insurance will be adequate. In some cases, a third party who has acquired assets including operating and deactivated nuclear power stations from us has assumed the liability we may otherwise have for environmental matters related to the transferred property. If the transferee fails to discharge the assumed liability or disputes its responsibility, a regulatory authority or injured person could attempt to hold us responsible, and our remedies against the transferee may be limited by the financial resources of the transferee. We Could be Exposed to Private Rights of Action Relating to Environmental Matters Seeking Damages Under Various State and Federal Law Theories Which Could Have an Adverse Impact on Our Results of Operations, Financial Condition, Cash Flows and Business Operations Private individuals may seek to enforce environmental laws and regulations against us and could allege personal injury, property damages or other relief. For example, claims have been made against certain energy companies alleging that CO_2 emissions from power generating facilities constitute a public nuisance under federal and/or state common law. While FirstEnergy is not a party to this litigation, it, and/or one of its subsidiaries, could be named in other actions making similar allegations. An unfavorable ruling in any such case could result in the need to make modifications to our coal-fired generation or reduce emissions, suspend operations or pay money damages or penalties. Adverse rulings in these or other types of actions could have an adverse impact on our results of operations, cash flows and financial condition and could significantly impact our business operations. We Are and May Become Subject to Legal Claims Arising from the Presence of Asbestos or Other Regulated Substances at Some of Our Facilities that May Have an Adverse Impact on Our Business Operations, Financial Condition and Cash Flows We have been named as a defendant in pending asbestos litigations involving multiple plaintiffs and multiple defendants, in several states. The majority of these claims arise out of alleged past exposures by contractors (and in Pennsylvania, former employees) at both currently and formerly owned electric generation plants. In addition, asbestos and other regulated substances are, and may continue to be, present at currently owned facilities where suitable alternative materials are not available. We believe that any remaining asbestos at our facilities is contained and properly identified in accordance with applicable governmental regulations, including OSHA. The continued presence of asbestos and other regulated substances at these facilities, however, could result in additional actions being brought against us. This is further complicated by the fact that many diseases, such as mesothelioma and cancer, have long latency periods in which the disease process develops, thus making it impossible to accurately predict the types and numbers of such claims in the near future. While insurance coverages exist for many of these pending asbestos litigations, others have no such coverages, resulting in FirstEnergy being responsible for all defense expenditures, as well as any settlements or verdict payouts. Risks Associated with Climate Change Matters Transition Risks Associated with Climate Change, Including Those Related to Regulatory Mandates Could Negatively Impact Our Financial Results Where federal or state legislation mandates the use of renewable fuel sources, such as wind and solar and such legislation does not also provide for adequate cost recovery, it could result in significant changes in our business, including material increases in renewable energy credit purchase costs, purchased power costs and capital investments. Such mandatory renewable portfolio requirements may have an adverse effect on our financial condition and results of operations. A number of regulatory and legislative bodies have introduced requirements and/or incentives to reduce peak demand and energy consumption. Such conservation programs could result in load reduction and adversely impact our financial results in different ways. We currently have energy efficiency riders in place in certain of our states to recover the cost of these programs either at or near a current recovery time frame in the states where we operate. In our regulated operations, energy conservation could negatively impact us depending on the regulatory treatment of the associated impacts. Should we be required to invest in conservation measures that result in reduced sales from effective conservation, regulatory lag in adjusting rates for the impact of these measures could have a negative financial impact. In the past, we have been adversely impacted by reduced electric usage due in part to energy conservation efforts such as the use of efficient lighting products such as compact fluorescent lights, halogens and light emitting diodes. We are unable to determine what impact, if any, conservation will have on our financial condition or results of operations. Additionally, failure to meet regulatory or legislative requirements to reduce energy consumption or otherwise increase energy efficiency could result in penalties that could adversely affect our financial results. Financial and Reputational Risks Associated with Owning Coal-Fired Generation and a Minority-Interest in a Coal Mine May Have an Adverse Impact on Our Business Operations, Financial Condition and Cash Flows MP's fleet consists of 3,093 MWs of coal-fired generation and FEV holds a 33-1/3% equity ownership in Global Holding, the holding company for a joint venture in the Signal Peak mining and coal transportation operations with coal sales in U.S. and international markets. Certain members of the investment community have adopted investment policies promoting the divestment of, or otherwise limiting new investments in, coal-fired generation and coal mining. The impact of such efforts may adversely affect the demand for and price of our common stock and impact our and MP's access to the capital and financial markets. Further, certain insurance companies have established policies limiting coal-related underwriting and investment. Consequently, these policies aimed at coal-fired generation could have a material adverse impact on our reputation, business operations, financial condition, and cash flows. The Physical Risks Associated with Climate Change May Have an Adverse Impact on Our Business Operations, Financial Condition and Cash Flows Physical risks of climate change, such as more frequent or more extreme weather events, changes in temperature and precipitation patterns, and other related phenomena, could affect some, or all, of our operations. Severe weather or other natural disasters could be destructive, which could result in increased costs, including supply chain costs. An extreme weather event within the Utilities' service areas can also directly affect their capital assets, causing disruption in service to customers due to downed wires and poles or damage to other operating equipment. Further, as extreme weather conditions increase system stress, we may incur costs relating to additional system backup or service interruptions, and in some instances, we may be unable to recover such costs. For all of these reasons, these physical risks could have an adverse financial impact on our business operations, financial condition and cash flows. Climate change poses other financial risks as well. To the extent weather conditions are affected by climate change, customers energy use could increase or decrease depending on the duration and magnitude of the changes. Increased energy use due to weather changes may require us to invest in additional system assets and purchase additional power. Additionally, decreased energy use due to weather changes may affect our financial condition through decreased rates, revenues, margins or earnings. Risks Associated with Markets and Financial Matters Our Results of Operations and Financial Condition May be Adversely Affected by the Volatility in Pension and OPEB Investments and Obligations Due to Capital Market Performance and Other Changes FirstEnergy recognizes in income the change in the fair value of plan assets and net actuarial gains and losses for its pension and OPEB plans. This adjustment is recognized in the fourth quarter of each year and whenever a plan is determined to qualify for a remeasurement, resulting in greater volatility in pension and OPEB expenses and may materially impact our results of operations. Our financial statements reflect the values of the assets held in trust to satisfy our obligations under pension and OPEB plans. Certain of the assets held in these trusts do not have readily determinable market values. Changes in the estimates and assumptions inherent in the value of these assets could affect the value of the trusts. If the value of the assets held by the trusts declines by a material amount, our funding obligation to the trusts could materially increase. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below our projected return rates. Forecasting investment earnings and costs to pay future pension and other obligations requires significant judgment and actual results may differ significantly from current estimates. Capital market conditions that generate investment losses or that negatively impact the discount rate and increase the present value of liabilities may increase our future pension and OPEB expenses and further may have significant impacts on the value of the pension and other trust funds, which could require significant additional funding and negatively impact our results of operations and financial position. Our Results of Operations and Financial Condition May be Adversely Affected by Certain Risks Related to our Minority Interest in a Coal Mine FEV currently holds a 33-1/3% equity ownership in Global Holding, the holding company for a joint venture in the Signal Peak mining and coal transportation operations with coal sales predominantly in international markets. In the second quarter of 2022, FEV received its first dividend of $20 million after more than ten years of equity ownership in the joint venture and received total dividends in 2022 of $170 million. Additionally, during 2022, FirstEnergy recognized approximately $168 million of pre-tax earnings (approximately $128 million after-tax) from its investment in Global Holding. Global Holdings ability to positively affect our results of operations or pay future dividends depends upon several factors beyond our control, including, but not limited to: the market price of coal, the availability and reliability of transportation facilities and other systems, and Global Holdings ability to renew and maintain governmental permits and approvals and remain in compliance with safety and environmental regulations affecting the coal mining industry. The price for Signal Peaks coal depends upon factors beyond our control, including: overall global economic conditions, the effect of worldwide energy consumption, including the impact of technological advances on energy consumption; international developments impacting the supply of coal; international developments impacting the supply of oil gas; and the impact of domestic and foreign governmental laws and regulations, including environmental and climate change regulations. Any adverse change in these factors could result in weaker demand and lower prices for Global Holdings products, and, as a result, could impact Global Holdings ability to pay future dividends or adversely affect our cash flow and results of operations. Failure to Comply with Debt Covenants in Our Credit Agreements or Conditions Could Adversely Affect Our Ability to Execute Future Borrowings and/or Require Early Repayment, and Could Restrict our Ability to Obtain Additional or Replacement Financing on Acceptable Terms or at All Our debt and credit agreements contain various financial and other covenants including a requirement for FE to maintain a consolidated interest coverage ratio of not less than 2.50 times, measured at the end of each fiscal quarter for the last four fiscal quarters beginning with the quarter ending December 31, 2021, and that each other borrower maintain a consolidated debt to total capitalization ratio of no more than 65%, and 75% for FET, measured at the end of each fiscal quarter. Our credit agreements contain certain negative and affirmative covenants. Our ability to comply with the covenants and restrictions contained in 2021 Credit Facilities has been and may, in the future, be affected by events related to the ongoing government investigations or otherwise, including a failure to comply with the terms of the DPA. A breach of any of the covenants contained in our credit agreements, including any breach related to alleged failures to comply with anti-corruption and anti-bribery laws, could result in an event of default under such agreements, and we would not be able to access our credit facilities for additional borrowings and letters of credit while any default exists. Upon the occurrence of such an event of default, any amounts outstanding under our credit facilities could be declared to be immediately due and payable and all applicable commitments to extend further credit could be terminated. If indebtedness under our credit facilities is accelerated, there can be no assurance that we will have sufficient assets to repay the indebtedness. In addition, certain events, including but not limited to any covenant breach related to alleged failures to comply with anti-corruption and anti-bribery laws, an event of default under our credit agreements, and the acceleration of applicable commitments under such facilities could restrict our ability to obtain additional or replacement financing on acceptable terms or at all. The operating and financial restrictions and covenants in our credit facilities and any future financing agreements may adversely affect our ability to finance future operations or capital needs or to engage in other business activities. Interest Rates and/or a Credit Rating Downgrade Could Negatively Affect Our or Our Subsidiaries' Financing Costs, Ability to Access Capital and Requirement to Post Collateral We have near-term exposure to interest rates from outstanding indebtedness indexed to variable interest rates, and we have exposure to future interest rates to the extent we seek to raise debt in the capital markets to meet maturing debt obligations and fund construction or other investment opportunities. Past disruptions in capital and credit markets have resulted in higher interest rates on new publicly issued debt securities, increased costs for variable interest rate debt securities and failed remarketing of variable interest rate tax-exempt debt issued to finance certain of our former facilities. Disruptions in capital and credit markets could result in higher interest rates on new publicly issued debt securities and increase our financing costs and adversely affect our results of operations. Also, interest rates could change as a result of economic or other events that are beyond our risk management processes. As a result, we cannot always predict the impact that our risk management decisions may have if actual events lead to greater losses or costs than our risk management positions were intended to hedge. Although we employ risk management techniques to hedge against interest rate volatility, significant and sustained increases in market interest rates could materially increase our financing costs and negatively impact our reported results of operations. We rely on access to bank and capital markets as sources of liquidity for cash requirements not satisfied by cash from operations. Additional downgrades in FirstEnergy or FirstEnergy subsidiaries' credit ratings from the nationally recognized credit rating agencies, particularly to levels below investment grade, could negatively affect our ability to access the bank and capital markets, especially in a time of uncertainty in either of those markets, and may require us to post cash collateral to support outstanding commodity positions in the wholesale market, as well as available letters of credit and other guarantees. Furthermore, additional downgrades could increase the cost of such capital by causing us to incur higher interest rates and fees associated with such capital. Additional rating downgrades would further increase our interest expense on certain of FirstEnergy's long-term debt obligations and would also further increase the fees we pay on our various existing credit facilities, thus increasing the cost of our working capital. Such additional rating downgrades could also negatively impact our ability to grow our regulated businesses or execute our business strategies by substantially increasing the cost of, or limiting access to, capital. In addition, events related to the ongoing government investigations may expose us to higher interest rates for additional indebtedness, whether as a result of ratings downgrades or otherwise, and could restrict our ability to obtain additional or replacement financing on acceptable terms or at all. See Failure to Comply with Debt Covenants in our Credit Agreements or Conditions Could Adversely Affect our Ability to Execute Future Borrowings and/or Require Early Repayment, and Could Restrict our Ability to Obtain Additional or Replacement Financing on Acceptable Terms or at All. In the Event of Volatility or Unfavorable Conditions in the Capital and Credit Markets, Our Business, Including the Immediate Availability and Cost of Short-Term Funds for Liquidity Requirements, Our Ability to Meet Long-Term Commitments and the Competitiveness and Liquidity of Energy Markets May be Adversely Affected, Which Could Negatively Impact Our Results of Operations, Cash Flows and Financial Condition We rely on the capital markets to meet our financial commitments and short-term liquidity needs if internal funds are not available from our operations. We also use LOCs provided by various financial institutions to support our hedging operations. We also deposit cash in short-term investments. In the event of volatility in the capital and credit markets, our ability to draw on our credit facilities and cash may be adversely affected. Our access to funds under those credit facilities is dependent on the ability of the financial institutions that are parties to the facilities to meet their funding commitments. Those institutions may not be able to meet their funding commitments if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests within a short period of time. Any delay in our ability to access those funds, even for a short period of time, could have a material adverse effect on our results of operations and financial condition. Should there be fluctuations in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant foreign or domestic financial institutions or foreign governments, our access to liquidity needed for our business could be adversely affected. Unfavorable conditions could require us to take measures to conserve cash until the markets stabilize or until alternative credit arrangements or other funding for our business needs can be arranged. Such measures could include deferring capital expenditures or other capital-like investments, changing hedging strategies to reduce collateral-posting requirements, and reducing or eliminating future dividend payments or other discretionary uses of cash. Energy markets depend heavily on active participation by multiple counterparties, which could be adversely affected should there be disruptions in the capital and credit markets. Reduced capital and liquidity and failures of significant institutions that participate in the energy markets could diminish the liquidity and competitiveness of energy markets that are important to our business. Perceived weaknesses in the competitive strength of the energy markets could lead to pressures for greater regulation of those markets or attempts to replace those market structures with other mechanisms for the sale of power, including the requirement of long-term contracts, which could have a material adverse effect on our results of operations and cash flows. The IRA of 2022 Could Change the Rate of Taxes Imposed On Us and Could Negatively Affect Our Cash Flows and Financial Condition On August 16, 2022, the U.S. President signed into law the IRA of 2022 which, among other things, imposes a new 15% corporate AMT based on AFSI, applicable to corporations with a three-year average AFSI over $1 billion. The AMT is effective for the 2023 tax year and, if applicable, corporations must pay the greater of the regular corporate income tax or the AMT. Although NOL carryforwards created through the regular corporate income tax system cannot be used to reduce the AMT, financial statement net operating losses can be used to reduce AFSI and the amount of AMT owed. The IRA of 2022 as enacted requires the U.S. Treasury to provide regulations and other guidance necessary to administer the AMT, including further defining allowable adjustments to determine AFSI, which directly impacts the amount of AMT to be paid. Based on interim guidance issued by U.S. Treasury in late December 2022, FirstEnergy continues to believe that it is more likely than not it will be subject to the AMT beginning in 2023. Until final U.S. Treasury guidance is issued, the amount of AMT FirstEnergy would pay could be significantly different than current estimates or it may not be a payer at all. The regulatory treatment of the impacts of this legislation will also be subject to the discretion of the FERC and state public utility commissions. Any adverse development in this legislation, including guidance from U.S. Treasury and/or the IRS or unfavorable regulatory treatment, could reduce future cash flows and impact financial condition. Changes in Local, State or Federal Tax Laws Applicable to Us or Adverse Audit Results or Tax Rulings, and Any Resulting Increases in Taxes and Fees, May Adversely Affect Our Results of Operations, Financial Condition and Cash Flows FirstEnergy is subject to various local, state and federal taxes, including income, franchise, real estate, sales and use and employment-related taxes. We exercise significant judgment in calculating such tax obligations, booking reserves as necessary to reflect potential adverse outcomes regarding tax positions we have taken and utilizing tax benefits, such as carryforwards and credits. Additionally, various tax rate and fee increases may be proposed or considered in connection with such changes in local, state or federal tax law. We cannot predict whether legislation or regulation will be introduced, the form of any legislation or regulation, or whether any such legislation or regulation will be passed by legislatures or regulatory bodies. Any such changes, or any adverse tax audit results or adverse tax rulings on positions taken by FirstEnergy or its subsidiaries could have a negative impact on its results of operations, financial condition and cash flows. We cannot predict whether, when or to what extent new U.S. tax laws, regulations, interpretations or rulings will be issued. A reform of U.S. tax laws may be enacted in a manner that negatively impacts our cash flow, results of operations, and financial condition. The Transition from LIBOR to SOFR Could Adversely Affect our Financial Results A portion of FirstEnergys indebtedness bears interest at fluctuating interest rates, primarily based on LIBOR. LIBOR tends to fluctuate based on general interest rates, rates set by the U.S. Federal Reserve and other central banks, the supply of and demand for credit in the London interbank market and general economic conditions. FirstEnergy has not hedged its interest rate exposure with respect to its floating rate debt. Accordingly, FirstEnergys interest expense for any particular period will fluctuate based on LIBOR and other variable interest rates. On July 27, 2017, the FCA (the authority that regulates LIBOR) announced that it intends to stop compelling banks to submit rates for the calculation of LIBOR after 2021, and according to the FCA, IBA will permanently cease to publish overnight, 1-month, 3-month, 6-month and 12-month LIBOR settings on June 30, 2023. FirstEnergys 2021 Credit Facilities provide a mechanism to automatically transition to a SOFR-based benchmark when all U.S. dollar LIBOR settings are no longer provided or are no longer representative. In addition, FirstEnergys 2021 Credit Facilities provide an option for the applicable borrower and lender to jointly elect to transition early to a SOFR-based benchmark, or in certain circumstances, an alternative benchmark replacement. It is not possible to predict the effect of these changes, other reforms or the establishment of alternative reference rates in the United Kingdom, the United States or elsewhere. To the extent these interest rates increase, interest expense will increase. If sources of capital for FirstEnergy are reduced, capital costs could increase materially. Restricted access to capital markets and/or increased borrowing costs could have an adverse effect on our results of operations, cash flows, financial condition and liquidity. We Must Rely on Cash from Our Subsidiaries and Any Restrictions on the Utilities and Transmission Companies Ability to Pay Dividends or Make Cash Payments to Us May Adversely Affect Our Cash Flows and Financial Condition We are a holding company and our investments in our subsidiaries are our primary assets. Substantially all of our business is conducted by our subsidiaries. Consequently, our cash flow, including our ability to pay dividends and service debt, is dependent on the operating cash flows of our subsidiaries and their ability to upstream cash to the holding company. Any inability of our subsidiaries to pay dividends or make cash payments to us may adversely affect our cash flows and financial condition. Additionally, the Utilities and Transmission Companies are regulated by various state utility and federal commissions that generally possess broad powers to ensure that the needs of utility customers are being met. Those state and federal commissions could attempt to impose restrictions on the ability of the Utilities and Transmission Companies to pay dividends or otherwise restrict cash payments to us. We Cannot Assure Common Shareholders that Future Dividend Payments Will be Made, or if Made, in What Amounts They May be Paid The FE Board will continue to regularly evaluate our common stock dividend and determine whether to declare a dividend, and an appropriate amount thereof, each quarter taking into account such factors as, among other things, our earnings, financial condition and cash flows from subsidiaries, as well as general economic and competitive conditions. We cannot assure common shareholders that dividends will be paid in the future, or that, if paid, dividends will be at the same amount or with the same frequency as in the past. The Tax Characterization of Our Distributions to Shareholders Will Fluctuate When we make distributions to shareholders, we are required to subsequently determine and report the tax characterization of those distributions for purposes of shareholders income taxes. Whether a distribution is characterized as a dividend or a return of capital (and possible capital gain) depends upon an internal tax calculation to determine earnings and profits for income tax purposes (EP). EP should not be confused with earnings or net income under GAAP. Further, after we report the expected tax characterization of distributions we have paid, the actual characterization could vary from our expectation with the result that holders of our common stock could incur different income tax liabilities than expected. In general, distributions are characterized as dividends to the extent the amount of such distributions do not exceed our calculation of current or accumulated EP. Distributions in excess of current and accumulated EP may be treated as a non-taxable return of capital. Generally, a non-taxable return of capital will reduce an investors basis in our stock for federal tax purposes, which will impact the calculation of gain or loss when the stock is sold. Our internal calculation of EP can be impacted by a variety of factors. FirstEnergy exhausted its accumulated EP in the second half of the 2019 tax year. This elimination of accumulated EP will make it more likely that at least a portion of our current or future distributions will be characterized for shareholders tax purposes as a return of capital. Upon such characterization, shareholders are urged to consult their own tax advisors regarding the income tax treatment of our distributions to them.

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ITEM 1. BUSINESS. General Portland General Electric Company (PGE or the Company), a vertically-integrated electric utility with corporate headquarters located in Portland, Oregon, is engaged in the generation, wholesale purchase, transmission, distribution, and retail sale of electricity in the state of Oregon (State). The Company operates as a cost-based, regulated electric utility with revenue requirements and customer prices determined based on the forecasted cost to serve retail customers and a reasonable rate of return as determined by the Public Utility Commission of Oregon (OPUC). PGE meets its retail load requirement with both Company-owned generation and power purchased in the wholesale market. The Company participates in the wholesale market through the purchase and sale of electricity and natural gas in an effort to obtain reasonably-priced power to serve its retail customers. PGE is committed to developing products and service offerings for the benefit of retail and wholesale customers. PGE, incorporated in 1930, is publicly-owned, with its common stock listed on the New York Stock Exchange (NYSE). The Company operates as a single business segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis. The Company owns unregulated, non-utility real estate comprised primarily of PGEs corporate headquarters. PGEs State-approved service area allocation of four thousand square miles is located entirely within Oregon and includes 51 incorporated cities. During 2022, the Company added nine thousand customers, and as of December 31, 2022, served a total of 926 thousand retail customers. Available Information PGEs periodic and current reports, and amendments to those reports, are available and may be accessed free of charge through the Investors section of the Companys website at PortlandGeneral.com as soon as reasonably practicable after the reports are electronically filed with, or furnished to, the United States Securities and Exchange Commission (SEC). It is not intended that PGEs website and the information contained therein or connected thereto be incorporated into this Annual Report on Form 10-K. Regulation Federal and State regulation each have a significant influence on PGEs business operations. In addition to the agencies and activities discussed below, the Company is subject to regulation by certain environmental agencies, as described in the Environmental Matters section in this Item 1. Federal Regulation Several federal agencies, including the Federal Energy Regulatory Commission (FERC), the U.S. Department of Transportations Pipeline and Hazardous Materials Safety Administration (PHMSA), and the Nuclear Regulatory Commission (NRC), have regulatory authority over certain of PGEs operations and activities, as described in the discussion that follows. PGE is a licensee, a public utility, and a user, owner, and operator of the bulk power system, as those terms are defined in the Federal Power Act (FPA). As such, the Company is subject to regulation by the FERC in matters related to wholesale energy activities, transmission services, reliability and cybersecurity standards, natural gas pipelines, hydroelectric projects, accounting policies and practices, short-term debt issuances, and certain other matters. Wholesale Energy PGE has authority under its FERC Market-Based Rates tariff to charge market-based rates for wholesale energy sales in all markets in which it sells electricity except in its own Balancing Authority Area (BAA). The BAA is the area in which PGE is responsible for balancing customer demand with electricity supply, in real time, and the tariff exception within PGEs BAA does not have a material impact on the Company. Transmission PGE offers wholesale electricity transmission service pursuant to its Open Access Transmission Tariff (OATT), which contains rates, terms, and conditions of service, as filed with, and approved by, the FERC. Reliability and Cybersecurity Standards The FERC has adopted mandatory reliability standards for owners, users, and operators of the bulk power system. Such standards, which are applicable to PGE, were developed by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC), which have responsibility for compliance and enforcement of these standards, and are intended to help protect critical cyber and physical assets used to support reliable operations. Natural Gas Pipelines The FERC has authority in matters related to the construction, operation, extension, enlargement, safety, and abandonment of jurisdictional interstate natural gas pipeline facilities, as well as transportation rates and accounting for interstate natural gas commerce. PGE is subject to such authority as the Company has a 79.5% ownership interest in the Kelso-Beaver (KB) Pipeline, a 17-mile, 20-inch diameter, interstate pipeline that provides natural gas to

Port Westward Unit 1 (PW1), Port Westward Unit 2 (PW2), and Beaver, the Companys natural gas-fired generating plants located near Clatskanie, Oregon, to the North Mist storage facility (owned and operated by a local natural gas distribution company), and to one additional local delivery point that serves a manufacturing concern. As the operator of record of the KB Pipeline, PGE is subject to the requirements and regulations enacted under the Pipeline Safety Laws administered by the PHMSA, which include safety and operator qualification standards in addition to public awareness requirements. Hydroelectric Licensing As required under the FPA, PGE holds FERC licenses for all Company-owned and operated hydroelectric generating plants. The FERC license process includes an extensive public review process that involves the consideration of numerous natural resource issues and environmental conditions. For additional information, see the Environmental Matters section in this Item 1. and the Generating Facilities section in Item 2.Properties. Accounting Policies and Practices PGE prepares periodic and current reports in accordance with accounting principles generally accepted in the United States of America (GAAP). In addition, the Company prepares, pursuant to applicable provisions of the FPA, financial statements in accordance with the accounting requirements of the FERC, as set forth in its applicable Uniform System of Accounts and published accounting releases. Such financial statements are included in annual and quarterly reports filed with the FERC. Short-term Debt Pursuant to applicable provisions of the FPA and FERC regulations, regulated public utilities are required to obtain FERC approval to issue certain securities. For additional information on the Companys Short-term Debt, see Short-term Debt in the Debt and Equity section of Liquidity and Capital Resources in Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Spent Fuel Storage The NRC regulates the licensing and decommissioning of nuclear power plants, including PGEs decommissioned Trojan nuclear power plant (Trojan), which was closed in 1993. For additional information on spent nuclear fuel storage activities, see Note 8, Asset Retirement Obligations in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data and Hazardous Material in the Environmental Matters section of this Item 1. State Regulation PGE is subject to the jurisdiction of the OPUC, which reviews and approves the Companys retail prices and reviews the Companys generation and transmission resource acquisition plans, pursuant to a biennial integrated resource planning process. The OPUC regulates the issuance of securities, prescribes accounting policies and practices, regulates the sale of utility assets, reviews transactions with affiliated companies, and has jurisdiction over the acquisition of, or exertion of substantial influence over, public utilities. Retail customer prices are determined through formal public proceedings that generally include testimony by participating parties, discovery, public hearings, and the issuance of a final order by the OPUC. Participants in such proceedings may include PGE, OPUC staff, and intervenors representing PGE customer groups, as well as other interested parties. The following lists the more significant regulatory mechanisms and proceedings under which customer prices are determined: General Rate Cases . PGE periodically

evaluates the need to update its retail electric price structure as part of a comprehensive general rate case process that reflects revenue requirements based on a forecasted test year. The OPUC authorizes the Companys debt-to-equity capital structure, return on equity, overall rate of return, and customer prices. Annual Power Cost Updates . The OPUC has approved an Annual Power Cost Update Tariff (AUT) by which PGE can adjust retail customer prices annually to reflect forecasted changes in the Companys net variable power costs (NVPC). NVPC consists of the cost of power purchased and fuel used to generate electricity, as well as the cost of settled electric and natural gas financial contracts (all classified as Purchased power and fuel expense in the Companys consolidated statements of income) and is net of wholesale revenues, which are classified in the consolidated statements of income as Revenues, net. The OPUC has also authorized a Power Cost Adjustment Mechanism (PCAM), under which PGE may share with customers a portion of actual cost variances associated with NVPC. Renewable Energy. The State has a Renewable Portfolio Standard (RPS) that requires PGE to serve a portion of its retail load with renewable resources. In conjunction with the RPS, the State established a Renewable Adjustment Clause (RAC) mechanism that allows for the recovery in retail customer prices, outside of a general rate case, of prudently incurred costs to comply with the RPS. In 2016, the State also passed Oregon Senate Bill (SB) 1547, a law referred to as the Oregon Clean Electricity and Coal Transition Plan, which, among its provisions, increased the RPS percentages in certain future years and required the elimination of coal from Oregon utility customers energy supply. For further information on SB 1547, see RPS standards and other laws in the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. During 2021, the State legislature passed House Bill (HB) 2021, which establishes clean energy targets and sets out a framework that includes, among other things, the development and submittal of clean energy plans for investor-owned utilities, including PGE, and electric service suppliers in the State. The targets are an 80% reduction in greenhouse gas (GHG) emissions by 2030, 90% by 2035, and 100% by 2040 and every year thereafter. For further information on HB 2021 and the baseline to which the target reductions apply, see HB 2021 in the Laws and Regulations portion of the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Regulatory Accounting PGE prepares financial statements in accordance with GAAP and, as a regulated public utility, the effects of rate regulation are reflected in its financial statements. GAAP provides for the deferral, as regulatory assets, of certain actual or estimated costs that would otherwise be charged to expense, based on expected recovery from customers in future prices. Likewise, certain actual or anticipated credits that would otherwise be recognized as revenue or reduce expense can be deferred as regulatory liabilities, based on expected future credits or refunds to customers. PGE records regulatory assets or liabilities if it is probable that they will be reflected in future prices, based on regulatory orders or other available evidence. The Company periodically assesses the applicability of regulatory accounting to its business, considering both the current and

anticipated future regulatory environment and related accounting guidance . For additional information, see Regulatory Assets and Liabilities in Note 2, Summary of Significant Accounting Policies, and Note 7, Regulatory Assets and Liabilities, in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data. Customers and Revenues PGE generates revenue primarily through the sale and delivery of electricity to retail customers located exclusively in Oregon. In addition, the Company distributes power to customers that choose to purchase their energy from an Electricity Service Supplier (ESS). Although the Company includes such Direct Access customers in its customer counts and energy delivered to such commercial and industrial customers in its total retail energy deliveries, retail revenues include only delivery charges and applicable transition adjustments for these Direct Access customers, as the customers purchase energy directly from the ESSs. The Company conducts retail electric operations within its State-approved service territory and competes with ESSs to supply certain commercial and industrial customer energy needs. In addition, PGE competes with the local natural gas distribution company for the energy needs of residential and commercial space heating, water heating, and appliances. Energy efficiency, conservation measures, and the advancement of distributed generation, including rooftop solar, and storage resources also have an influence on customer demand. Retail Revenues Retail customers are classified as residential, commercial, or industrial, with no single customer representing more than 8% of PGEs total retail revenues or 13% of total retail deliveries. PGEs Retail revenues, retail energy deliveries, and average number of retail customers consist of the following: ##TABLE_START Years Ended December 31, 2022 2021 2020 Retail revenues (1) (dollars in millions): Residential $ 1,158 52 % $ 1,118 54 % $ 1,030 53 % Commercial 735 33 708 34 634 33 Industrial 312 14 279 13 246 13 Subtotal 2,205 99 2,105 101 1,910 99 Alternative revenue programs, net of amortization 11 1 (29) (1) (6) Other accrued revenues, net (2) 7 2 28 1 Total retail revenues $ 2,223 100 % $ 2,078 100 % $ 1,932 100 % Retail energy deliveries (3) (MWh in thousands): Residential 8,088 38 % 7,978 39 % 7,756 40 % Commercial 7,198 34 7,193 35 6,855 35 Industrial 5,945 28 5,361 26 4,932 25 Total retail energy deliveries 21,231 100 % 20,532 100 % 19,543 100 % Average number of retail customers: Residential 809,573 88 % 800,372 88 % 791,119 88 % Commercial 112,602 12 111,569 12 110,851 12 Industrial 269 268 267 Total 922,444 100 % 912,209 100 % 902,237 100 % ##TABLE_END##TABLE_START ##TABLE_END(1) Includes both revenues from customers who purchase their energy supplies from the Company and revenues from the delivery of energy to those commercial and industrial customers that purchase their energy from ESSs. (2) Amount for the year ended December 31, 2020 is primarily comprised of $24 million of amortization, including interest, related to the deferral recorded in 2018 for the net tax benefits due to the change in corporate tax rate under the United States Tax Cuts and Jobs Act of 2017 (TCJA). (3) Includes both energy sold to retail customers and energy deliveries to those commercial and industrial customers that purchase their energy from ESSs. The following table presents additional annual

averages for retail customers. Certain supplemental tariff collections are excluded from revenues as they are not considered a part of the Companys base retail prices for these calculations. ##TABLE_START Years Ended December 31, 2022 2021 2020 Residential Revenue per customer (in dollars): $ 1,362 $ 1,320 $ 1,226 Usage per customer (in kilowatt hours): 9,991 9,968 9,804 Revenue per kilowatt hour (in cents): 13.63 13.24 12.50 Commercial Revenue per customer (in dollars): $ 6,491 $ 6,303 $ 5,684 Usage per customer (in kilowatt hours): 63,923 64,478 61,837 Revenue per kilowatt hour (in cents): 10.15 9.78 9.19 Industrial Revenue per customer (in dollars): $ 1,156,371 $ 1,044,314 $ 921,540 Usage per customer (in kilowatt hours): 22,097,472 20,002,246 18,472,161 Revenue per kilowatt hour (in cents): 5.23 5.22 4.99 ##TABLE_ENDFor additional information, see the Results of Operations section in Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. In addition to standard cost-of-service pricing, the Company offers different pricing options including a daily market price option, various time-of-use options, and several renewable energy options. For additional information on customer options, see Customer Choice Programs within this Customers and Revenues section of this Item 1. Residential customers include single family housing, multiple family housing (such as apartments, duplexes, and town homes), mobile homes, and small farms. Residential demand is sensitive to the effects of weather. The Company had seen its highest peak demand during the winter heating season although increased use of air conditioning in PGEs service territory has caused the summer peaks to increase over time. In recent years, including 2022, summer peaks have exceeded winter peaks and long-term load forecasts expect that trend to continue. An extreme winter temperature event on December 22, 2022, caused a new winter peak for the first time since 1998. Economic conditions can also affect residential demand as job growth and population growth in PGEs service territory have led to increased customer growth rates. The COVID-19 pandemic has introduced additional behavioral patterns as residential customers spend more time at home. Residential demand is also impacted by energy efficiency measures and increased rooftop solar penetration in the service territory; however, the Companys decoupling mechanism was intended to mitigate the financial effects of such measures. For further information regarding the decoupling mechanism, see Decoupling among the Regulatory Matters in the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Commercial customers consist of non-residential customers who accept energy deliveries at voltages equivalent to those delivered to residential customers. This customer class includes most businesses, small industrial companies, and public street and highway lighting accounts. The Companys commercial customer demand is somewhat less susceptible to weather conditions than residential customer demand. Economic conditions and fluctuations in total employment in the region can lead to changes in energy demand from commercial customers. Energy efficiency measures also impact commercial demand, as measures have focused in the commercial sector in recent years, although the Companys decoupling mechanism was intended to partially mitigate the financial

effects of such measures. For further information regarding the decoupling mechanism, see Decoupling among the Regulatory Matters in the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Industrial customers consist of non-residential customers who accept delivery at higher voltages than commercial customers, with pricing based on the amount of electricity delivered under the applicable tariff. Demand from industrial customers is primarily driven by economic conditions, with weather having little impact on this customer class. Customer Choice Programs Under cost-of-service pricing, residential and small commercial customers may select portfolio options from PGE that include time-of-use and renewable resource pricing. Pricing options other than cost-of-service are available to certain commercial and industrial customers for a one-year period, including daily market index-based pricing under which the Company provides the electricity, and Direct Access, whereby customers purchase electricity directly from an ESS. PGE receives revenue from Direct Access customers only for the transmission and delivery of the volume of electricity delivered, along with fixed transition adjustments intended to mitigate the shifting of excess charges to the Companys cost-of-service customers. Certain large commercial and industrial customers may elect a fixed three-year or a minimum five-year term, to be served either by an ESS, or by the Company under the daily market index-based price option. Participation in the fixed three-year and minimum five-year opt-out programs for existing and planned load is capped at 300 average megawatts (MWa) in aggregate. In 2020, the OPUC issued an order that required PGE to begin offering, to eligible customers, enrollment in the New Large Load Direct Access program, which is capped at 119 MWa in total, for unplanned, large, new loads and large load growth at existing sites. For further information regarding Direct Access deliveries, see Customers and demand in the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. PGEs customers have a desire for purchasing clean energy, as over 234 thousand residential and small commercial customers voluntarily participate in PGEs Green Future Program, the largest renewable power program by participation in the nation. Oregons most populous city, Portland, and most populous county, Multnomah, have each passed resolutions to achieve 100 percent clean and renewable electricity by 2035 and 100 percent economy-wide clean and renewable energy by 2050. Other jurisdictions in PGEs service area have set, or are considering, similar goals. The Company implemented a new customer service option, the Green Future Impact Program, which allows for 100 MW of PGE-provided power purchase agreements for renewable resources and up to 200 MW of customer-provided renewable resources. Approved by the OPUC in 2019, the program provides business customers access to bundled renewable attributes from those resources. In March 2021, the OPUC issued an order that expanded the program by 200 MW and provided for the possibility of PGE ownership of the underlying renewable resources under certain conditions. Through this voluntary program, the Company seeks to align sustainability goals, cost and risk management, and reliable integrated power while

providing customer choice and a cleaner energy system. In December 2021, the OPUC issued an order, which approved a petition to increase capacity under the customer-provided renewable resources by 250 MW, which brings the total available capacity under the program to 750 MW. For more information on the Companys power purchase agreements that currently serve the Green Future Impact Program, see Green Future Impact Program within Purchased Power in the Power Supply section of this Item 1. Wholesale Revenues PGE participates in the wholesale electricity marketplace in order to balance its supply of power to meet the needs of its retail customers. Interconnected transmission systems in the western United States serve utilities with diverse load requirements and allow the Company to purchase and sell electricity, largely through bi-lateral agreements, within the region to serve retail demand. PGEs engagement in the wholesale electricity marketplace depends upon numerous factors, including the relative price and availability of power, hydro and wind conditions, and daily and seasonal retail demand. The Company also participates in the California Independent System Operators western Energy Imbalance Market (western EIM), which allows for load balancing with other western EIM participants in five-minute intervals. Wholesale revenues represented 14% of total revenues in 2022, 11% in 2021, and 8% in 2020. Other Operating Revenues Other operating revenues consist primarily of gains and losses on the sale of natural gas volumes purchased that exceeded what was needed to fuel the Companys generating facilities, as well as revenues from transmission services, excess transmission capacity resales, pole attachment rentals, and other electric services provided to customers. Other operating revenues represented 2% of total revenues in 2022, 3% in 2021, and 2% in 2020. Seasonality Demand for electricity by PGEs residential and, to a lesser extent, commercial customers is affected by seasonal weather conditions. The Company uses heating and cooling degree-days to determine the effect of weather on the demand for electricity. Heating and cooling degree-days, determined by taking the difference between the average daily temperature and a baseline of 65 degrees, provide cumulative variances over a period of time, to indicate the extent to which customers are likely to have used electricity for heating or cooling. The higher the number of degree-days, the greater the expected demand for electricity. The following table presents the heating and cooling degree-days for the most recent three-year period, along with current 15-year averages for the most recent year provided by the National Weather Service, as measured at Portland International Airport: ##TABLE_START Heating Degree-Days Cooling Degree-Days 2022 4,103 865 2021 3,828 838 2020 3,836 600 15-year average 4,103 569 ##TABLE_ENDIn June 2021, PGE set a new all-time high net system load peak of 4,453 megawatts (MW), surpassing the previous all-time peak that occurred in December 1998 by more than 9%. While the Companys previous summer peak of 3,976 MW had occurred in August 2017, that level has been exceeded now in each of the past two summers. In December 2022, a new winter peak of 4,113 MW occurred. The following table presents PGEs average winter (defined as January, February, and December) and summer (defined as June through September) loads for the periods

presented, along with the corresponding peak load (in MWs) and month in which such peak occurred. As illustrated, although the average winter loads continue to exceed average summer loads, the Company has seen its highest annual peak loads during the summer months in recent years: ##TABLE_START Winter Loads Summer Loads Average Peak Month Average Peak Month 2022 2,773 4,113 December 2,529 4,255 July 2021 2,659 3,629 December 2,492 4,453 June 2020 2,566 3,367 December 2,289 3,771 July ##TABLE_ENDThe Company tracks and evaluates both load growth and peak load requirements for purposes of long-term load forecasting, integrated resource planning, and preparing general rate case assumptions. Behavior patterns, conservation, energy efficiency initiatives and measures, weather effects, economic conditions, distributed generation including rooftop solar, transportation and building electrification, and demographic changes all play a role in determining expected future customer demand and the resulting resources the Company may need to adequately meet those loads and maintain adequate capacity reserves. Power Supply PGE utilizes its generating resources, as well as wholesale power purchases from third parties to meet the needs of its retail customers. The volume of electricity the Company generates is dependent upon, among other factors, the capacity and availability of its generating resources and the price and availability of wholesale power and natural gas. As part of its power supply operations, the Company enters into short- and long-term power and fuel purchase and sale agreements. PGE executes economic dispatch decisions concerning its own generation and participates in the wholesale market in an effort to obtain reasonably-priced power for its retail customers, manage risk, and administer its long-term wholesale contracts. The Company also performs portfolio management and wholesale market sales services for third parties in the region. The Company also encourages energy efficiency measures to help meet its energy requirements and promotes the use of various demand side management products to reduce load during peak time usage. PGEs resource and contracted capacity (in MW) was as follows: ##TABLE_START As of December 31, 2022 2021 Capacity % Capacity % Generation: Thermal (1) : Natural gas 1,842 32 % 1,842 35 % Coal 296 4 296 5 Total thermal 2,138 37 2,138 40 Wind (2) 817 15 817 16 Hydro (3) 419 7 495 9 Total generation 3,374 59 3,450 65 Purchased power: Long-term contracts: Hydro (3) 871 15 803 15 PURPA qualifying facilities (4) 315 5 298 6 Dispatchable standby generation 130 2 130 2 Capacity 100 2 100 2 Wind (2) 300 5 300 6 Solar (5) 57 1 7 Biomass 10 10 Total long-term contracts 1,783 31 1,648 31 Short-term contracts 597 10 216 4 Total purchased power capacity 2,380 41 1,864 35 Total resource capacity 5,754 100 % 5,314 100 % ##TABLE_END##TABLE_START ##TABLE_END(1) Capacity represents the MW the plants are capable of generating under normal operating conditions, which is affected by ambient temperatures, net of electricity used in the operation of the plant. (2) Capacity represents nameplate and differs from expected energy to be generated, which is expected to have a capacity factor range from 30 to 40%, dependent upon wind conditions. (3) Capacity represents net capacity and differs from expected energy to be generated, which is expected to have a capacity factor range from 40 to 50%,

dependent upon river flows. (4) Capacity represents contracted capacity for power purchase agreements (PPAs) under the Public Utility Regulatory Policies Act of 1978 (PURPA). (5) Capacity includes 50 MW from the solar component of Wheatridge. The Wheatridge facility also includes 30 MW related to the battery component which is not reflected in the table above. For information regarding actual generating output and purchases for the years ended December 31, 2022 and 2021, see the Results of Operations section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Generation PGEs generating resources consist of six thermal plants (natural gas- and coal-fired), three wind farms, and seven hydroelectric facilities. The portion of PGEs retail load requirements generated by its plants varies from year to year and is determined by various factors, including planned and unplanned outages, availability and price of coal and natural gas, precipitation and snow-pack levels, the market price of electricity, and wind variability. For a complete listing of these facilities, see Generating Facilities in Item 2.Properties. Thermal The Company has five natural gas-fired generating facilities: PW1, PW2, Beaver, Coyote Springs Unit 1 (Coyote Springs), and Carty Generating Station (Carty). The Company operated, and continues to have a 90% ownership interest in the Boardman coal-fired generating plant (Boardman), which ceased coal-fired operations during the fourth quarter of 2020. The Company has begun decommissioning the facility. The Company also has a 20% ownership interest in the Colstrip Units 3 and 4 coal-fired generating plant (Colstrip), which is located in Colstrip, Montana and operated by a third party. For additional information on Colstrip as it relates to environmental laws and regulations in the State, see RPS standards and other laws in the Overview section in Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations and Note 19, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data. Wind PGE owns and operates two wind farms, Biglow Canyon Wind Farm (Biglow Canyon) and Tucannon River Wind Farm (Tucannon River). Biglow Canyon, located in Sherman County, Oregon, consists of 217 turbines with a total nameplate capacity of 450 MW. Tucannon River, located in southeastern Washington, consists of 116 turbines with a total nameplate capacity of 267 MW. During 2020, the wind component of the Wheatridge Renewable Energy Facility (Wheatridge), located in Morrow County, Oregon, was placed into service. Although PGE does not operate Wheatridge, it owns 40 turbines with a total nameplate capacity of 100 MW and purchases the output of the remaining turbines, with a nameplate capacity of 200 MW through power purchase agreement. PGE and NextEra Energy Resources, LLC, a subsidiary of NextEra Energy, Inc. have entered into agreements to construct a 311 MW wind energy facility, which will be part of the larger Clearwater Wind development in Eastern Montana. This additional wind capacity is not reflected in the table above. For more information regarding the Clearwater Wind development, see The Resource Planning Process within the Overview section of Item 7 Managements Discussion and Analysis of Financial Condition and Results of Operations. Hydro The Companys FERC-licensed

hydroelectric projects consist of Pelton/Round Butte on the Deschutes River near Madras, Oregon (discussed below), four plants on the Clackamas River, and one on the Willamette River. As of December 31, 2021, PGE had a 66.67% ownership interest in the 455 MW Pelton/Round Butte hydroelectric project on the Deschutes River, with the remaining interest held by the Confederated Tribes of the Warm Springs Reservation of Oregon (CTWS). A 50-year joint license for the project, which is operated by PGE, was issued by the FERC in 2005. The CTWS had an option to purchase an additional undivided 16.66% ownership interest in Pelton/Round Butte in 2021, and closed on the purchase of this incremental undivided ownership interest on January 1, 2022. As a result, PGEs ownership interest in the project is 50.01%. CTWS has a second option in 2036 to purchase an undivided 0.02% interest in Pelton/Round Butte. If the second option is exercised, CTWSs ownership percentage would exceed 50%. PGE purchases 100% of the CTWSs share of the project output. For more information see CTWS within Purchased Power in the Power Supply section of this Item 1. Fuel Supply PGE contracts for natural gas and coal supplies required to fuel the Companys thermal generating plants, with certain plants also able to operate on fuel oil, if needed. In addition, the Company uses forward, future, swap, and option contracts to manage its exposure to volatility in natural gas prices. Natural Gas Physical supplies of natural gas are generally purchased up to twelve months in advance of delivery and based on anticipated operation of the plants. PGE manages the price risk of natural gas supply through the use of financial contracts up to 60 months in advance of expected need of energy. PGE owns 79.5%, and is the operator of record, of the KB Pipeline, which directly connects PW1, PW2, and Beaver to the Northwest Pipeline, an interstate natural gas pipeline operating between British Columbia and New Mexico. Currently, PGE transports natural gas on the KB Pipeline for its own use under a firm transportation service agreement, with capacity offered to others on an interruptible basis to the extent not utilized by the Company. PGE has access to 111,805 Dth per day of firm natural gas transportation capacity on the Northwest Pipeline to serve the three plants. PGE has access to 4.1 billion cubic feet of natural gas storage in Mist, Oregon from which it can draw when economic factors favor its use or in the event that natural gas supplies are interrupted. The storage facility, owned and operated by NW Natural, may be utilized to provide fuel to PW1, PW2, and Beaver. To serve Coyote Springs and Carty, PGE has access to 120,000 Dth per day of firm natural gas transportation capacity on three pipeline systems accessing gas fields in Alberta, Canada. Coal The Colstrip co-owners obtain coal to fuel the plant via conveyor belt from a mine that lies adjacent to the facility and is the sole source of coal supply for the plant. The coal supply contract with the owner of the mine is scheduled to expire at the end of 2025. The terms of the contract and the quality of coal are expected to allow the facility to operate within required emissions limits. Purchased Power PGE supplements its own generation with power purchased in the wholesale market to meet its retail load requirements. The Company utilizes short- and long-term wholesale power purchase contracts in an effort to provide the most favorable economic mix on a variable cost

basis. PGEs medium-term power cost strategy helps mitigate the effect of price volatility on its customers due to changing energy market conditions. The strategy allows the Company to take positions in power and fuel markets up to five years in advance of physical delivery. By purchasing a portion of anticipated energy needs for future years over an extended period, PGE mitigates a portion of the potential future volatility in the average cost of purchased power and fuel. The Companys major power purchase contracts consist of the following (also see the preceding table which summarizes the average resource capabilities related to these contracts): Hydro During 2022, the Company had the following agreements: Public Utility Districts PGE has long-term power purchase contracts with certain public utility districts (PUDs) in the state of Washington for a portion of the output of two hydroelectric projects on the mid-Columbia River. Although the projects currently provide PGE a total of 410 MW of capacity through contracts as shown below, actual energy received is dependent upon river flows and capacity amounts may decline over time: 162 MW of capacity with Grant County PUD that expires in 2052; 148 MW of capacity with Douglas County PUD that expires in 2028; and 100 MW of capacity with Douglas County PUD that expires in 2025. CTWS PGE has a long-term agreement under which the Company purchases output from CTWS interest in the Pelton/Round Butte hydroelectric project. Although the agreement provides approximately 224 MW of net capacity, actual energy received is dependent upon river flows. The term of the agreement coincides with the term of the FERC license for this project, which expires in 2055. Under a separate PPA executed in 2014, PGE pays fixed capacity and energy charges to CTWS for 100% of its share of the project through 2024. On June 30, 2021 the CTWS notified PGE of their intent to exercise their option to purchase an additional undivided 16.66% ownership interest in Pelton/Round Butte and closed on the purchase on January 1, 2022. As a result of the sale, capacity from company-owned generation decreased by approximately 76 MW, and capacity from purchased power increased by a corresponding amount. Under the PPA, PGE purchases 100% of the CTWSs additional share of the project and payments under the PPA increase proportionately. In the fourth quarter of 2021, PGE and CTWS executed an additional 16-year PPA which begins on January 1, 2025, that effectively extends the term from 2024 to 2040 and increases the capacity payments in the extension period. Other The remaining capacity is primarily comprised of two additional contracts that provide for the purchase of power generated from hydroelectric projects with capacity of 236 MW in total: 200 MW of capacity with Bonneville Power Administration that expires in 2024; and 36 MW of capacity with Portland Hydro that expires in 2032 PURPA qualifying facilities PGE is required to purchase power from PURPA qualifying facilities (QFs), as mandated by federal law. QFs are generating facilities that fall within the following two categories: i) qualifying generation facilities with a capacity of 80 MW or less and whose primary energy source is renewable (hydro, wind, solar, biomass, waste, or geothermal); or ii) qualifying cogeneration facilities that sequentially produce electricity and another form of useful thermal energy (e.g., heat, steam) in a way that is more efficient than the separate production of each form of

energy. As of December 31, 2022, PGE had contracts with 67 online QFs, providing a total of 315 MW of capacity. As of December 31, 2022, PGE has six contracts with QFs representing 127 MW of capacity that are not yet operational, of which two of the QF PPAs are in default because the QF has failed to complete construction and become operational by the date required by the PPA. The PPAs provide that the QF has one year to cure its default. If the QF has failed to cure, PGE is permitted to immediately terminate the QF PPA upon expiration of the cure period. The term of a QF PPA generally ranges from 15 to 23 years. The expense and volume of purchases from QFs for the years ended December 31, 2022 and 2021 were as follows: ##TABLE_START 2022 2021 PURPA contract expense (in millions) $ 62 $ 55 MWh purchased under PURPA contracts (in thousands) 750 683 Average cost per MWh from PURPA contracts $ 82.90 $ 79.89 ##TABLE_ENDExpenses incurred related to PURPA contracts are included in PGEs AUT. Dispatchable Standby Generation (DSG) PGE has a DSG program under which the Company can start, operate, and monitor customer-owned backup generators when needed to provide NERC-required operating reserves. As of December 31, 2022, there were 59 customer-owned sites with a total DSG capacity of 130 MW. PGE continues to pursue expansion of the program with the goal of having an additional 3 to 10 MW of customer-owned DSG projects online by the end of 2023. Capacity PGE has one capacity contract representing up to 100 MW of seasonal capacity during the summer and winter peak periods obtained from a natural gas-fired resource, which expires in 2024. Wind PGE has three contracts representing 300 MW of capacity to purchase power generated from renewable wind resources that extend to 2028, 2035, and 2051. The expected energy from these wind resources will vary from the nameplate capacity due to varying wind conditions. PGE and NextEra Energy Resources, LLC, a subsidiary of NextEra Energy, Inc. have entered into agreements to construct a 311 MW wind energy facility, which will be part of the larger Clearwater Wind development in Eastern Montana. This additional wind capacity is not reflected in the table above. For more information regarding the Clearwater Wind development, see The Resource Planning Process within the Overview section of Item 7 Managements Discussion and Analysis of Financial Condition and Results of Operations. Solar PGE has four contracts representing 57 MW of capacity to purchase power generated from photovoltaic solar projects. Two of these projects extend to 2036 while the other two extend to 2037 and 2042. The expected energy from these solar resources will vary from the nameplate capacity due to varying solar conditions. Construction on the solar and battery components of Wheatridge was completed in 2022. The solar component of Wheatridge supplies the Company with 50 MW of capacity. The facility also includes 30 MW related to the battery component which is not reflected in the table above. Subsidiaries of NextEra Energy Resources, LLC own the solar and battery components, and sell their portion of the output to PGE. Biomass PGE has one contract to purchase biomass energy that is set to expire in June 2023. Green Future Impact Program PGE has three contracts representing 360 MW of capacity to purchase power generated from renewable resources to support the Green Future

Impact Program: a 15-year contract with Avangrid Renewables representing 162 MW from a renewable solar facility in Gilliam County, Oregon that was placed in service in January 2023. This additional capacity is not reflected in the table above; and a 15-year contract with Avangrid Renewables representing 138 MW from a renewable solar facility in Wasco County, Oregon that is expected to be placed in service in December 2023. This additional capacity is not reflected in the table above. a 15-year contract with Avangrid Renewables representing 60 MW from a renewable solar facility in Wasco County, Oregon that is expected to be placed in service in December 2023. This additional capacity is not reflected in the table above. For additional information on the Green Future Impact Program, see Customer Choice Programs within the Customers and Revenues section of this Item 1. Short-term contracts These contracts are for delivery periods of one month up to one year in length. They are entered into with various counterparties to provide additional firm energy to help meet the Companys load requirements. PGE also utilizes spot purchases of power in the open market to secure the energy required to serve its retail customers. Such purchases are made under contracts that range in duration from 15 minutes to less than one month. PGE is a market participant in the western EIM, which allows certain of the Companys generating plants to receive automated dispatch signals from the California Independent System Operator (CAISO) for load balancing with other western EIM participants in five-minute intervals. For additional information regarding PGEs power purchase contracts, see Note 16, Commitments and Guarantees and Note 17, Leases, in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data. Future Energy Resource Strategy PGEs Integrated Resource Plan (IRP) outlines the Companys plan to meet future customer demand and describes PGEs future energy supply strategy. For a detailed discussion of the IRPs, see Investing in a Clean Energy Future within the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Transmission and Distribution Transmission systems deliver energy from generating facilities to distribution systems for final delivery to customers. PGE schedules energy deliveries over its transmission system in accordance with FERC requirements and operates one BAA in its service territory. In 2022, PGE delivered approximately 27 million megawatt hours (MWh) through 1,255 circuit miles of transmission lines operating at or above 115 kilovolts (kV). PGEs transmission system is part of the Western Interconnection, the regional grid in the western United States. The Western Interconnection includes the interconnected transmission systems of 11 western states, two Canadian provinces and parts of Mexico, and is subject to the reliability rules of the WECC and the NERC. PGE relies on transmission contracts with Bonneville Power Administration (BPA) to transmit a significant amount of the Companys generation to serve its distribution system. PGEs transmission system, together with contractual rights on other transmission systems, enables the Company to integrate and access generation resources to meet its customers energy requirements. PGEs generation is managed on a coordinated basis to obtain maximum load-carrying capability and efficiency. PGE has announced its

intention to join the Western Power Pool and a binding resource adequacy program for the region known as the Western Resource Adequacy Program (WRAP). For further information, see Operating Activities within the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. The Companys wholesale transmission activities are regulated by the FERC and are offered on a non-discriminatory basis, with all potential customers provided equal access to PGEs transmission system through PGEs OATT. In accordance with its OATT, PGE offers several transmission services to wholesale customers, including: Network integration transmission service, a service that integrates generating resources to serve retail loads; Short- and long-term firm point-to-point transmission service, a service with fixed delivery and receipt points; and Non-firm point-to-point service, an as available service with fixed delivery and receipt points. For additional information regarding the Companys transmission and distribution facilities, see Transmission and Distribution in Item 2.Properties. Environmental Matters PGEs operations are subject to a wide range of environmental protection laws and regulations, which pertain to air and water quality, endangered species and wildlife protection, and hazardous material. Various state and federal agencies also regulate environmental matters that relate to the siting, construction, and operation of generation, transmission, and substation facilities and the handling, accumulation, clean-up, and disposal of toxic and hazardous substances. In addition, certain of the Companys hydroelectric projects and transmission facilities are located on property under the jurisdiction of federal and state agencies, and/or tribal entities that have authority in environmental protection matters. The following discussion provides further information on certain environmental regulations that affect the Companys operations and facilities. Air Quality Clean Air Act PGEs operations, primarily its thermal generating plants, are subject to regulation under the federal Clean Air Act (CAA), which addresses particulate matter, hazardous air pollutants, and GHG emissions, among other things. Oregon and Montana, the states in which PGEs thermal facilities are located, also implement and administer certain portions of the CAA and have set standards that are at least as stringent as federal standards. PGE manages its air emissions at its thermal generating plants by the use of low sulfur fuel, emissions and combustion controls and monitoring, and sulfur dioxide allowances awarded under the CAA. Climate Change In 2015, the United States Environmental Protection Agency (EPA) released the Clean Power Plan (CPP), under which each state would have to reduce overall carbon dioxide emissions from its power sector on a state-wide basis. In 2016, the United States Supreme Court halted implementation and enforcement of the CPP. In 2018, the EPA proposed the more narrowly focused Affordable Clean Energy (ACE) rule, to repeal and replace the CPP and, in 2019, finalized the ACE rule, which established guidelines for states to develop plans to address GHG emissions from individual, existing coal-fired plants, such as Colstrip in the case of PGE. With the finalization of the ACE rule, the CPP was repealed. However, on January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE rule and remanded it, in full, back to the EPA. Notwithstanding

objections that the EPA intended to issue a new rule that took recent changes in the electricity sector into account, on October 29, 2021, the U.S. Supreme Court agreed to hear an appeal of the D.C. Circuit decision. The Supreme Court, in a February 28, 2022 decision, determined that the broad approach in the CPP regulating emissions exceeded the powers granted to EPA by Congress. The Court did not expressly determine whether EPA can regulate power sector GHG emissions through its other regulatory authority and the EPA has indicated it intends to issue a proposed successor rule to the CPP in March 2023. PGE will continue to assess the Supreme Courts decision, as well as any further EPA response, for impacts on Colstrip and the Companys existing natural gas fleet. House Bill (HB) 2021 In June 2021, the Oregon Legislature passed HB 2021, which requires retail electricity providers to reduce GHG emissions associated with serving Oregon retail electricity consumers 80% by 2030, 90% by 2035, and 100% by 2040, compared to their baseline emissions levels. The baseline levels for PGE are the average annual emissions for the years 2010, 2011, and 2012 associated with the electricity sold to its retail electricity consumers as reported to the Oregon Department of Environmental Quality (ODEQ). See HB 2021 in the Laws and Regulations section of the Overview for additional information. Any laws that would impose taxes or mandatory reductions in GHG emissions may have a material impact on PGEs operations, as the Company utilizes fossil fuels in its own power generation and other companies use such fuels to generate power that PGE purchases in the wholesale market. If incremental costs were incurred as a result of changes in the regulations regarding GHG emissions, the Company would seek recovery in customer prices. For more information regarding GHG emissions and related environmental regulation, including Oregons RPS and the Companys goals in this area, see Renewable Energy under State Regulation in the Regulation section of this Item 1. and Company Strategy in the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Water Quality The federal Clean Water Act requires that any federal license or permit to conduct an activity that may result in a discharge to waters of the United States must first receive a water quality certification or permit from the state in which the activity will occur. In Oregon, Montana, and Washington, the Department of Environmental Quality and Department of Ecology of each state are responsible for reviewing proposed projects under such requirements to ensure that federally approved activities will meet water quality standards and policies established by the respective state. PGE has obtained permits or certificates of compliance for its hydroelectric operations under the FERC licenses and continues to monitor and update equipment to meet federal and state standards. Threatened and Endangered Species and Wildlife Fish Protection The federal Endangered Species Act (ESA) has granted protection to many populations of migratory fish species in the Pacific Northwest. Long-term recovery plans for these species continue to have operational impacts on many of the regions hydroelectric projects. PGE continues to implement fish protection measures at its hydroelectric projects that were prescribed by the U.S. Fish and Wildlife Service and the National

Marine Fisheries Service under their authority granted in the ESA and the FPA. Conditions required with the operating licenses are expected to result in a minor reduction in power production and continued capital spending to modify the facilities to enhance fish passage and survival. Avian Protection Various statutes, including the Migratory Bird Treaty Act and Bald and Golden Eagle Protection Act, contain provisions for civil, criminal, and administrative penalties resulting from the unauthorized take of migratory birds and eagles. Because PGE operates facilities that can pose risks to a variety of such birds and eagles, the Company developed an Avian Protection Plan to help address and reduce risks to avian species that may be affected by Company operations. PGE has implemented such a plan for its transmission, distribution, and thermal generation facilities and additional, specific plans for its wind generation facilities. Hazardous Material PGE has a comprehensive program to comply with requirements of both federal and state regulations related to the storage, handling, and disposal of hazardous materials. The handling and disposal of hazardous materials from Company facilities is subject to regulation under the federal Resource Conservation and Recovery Act. In addition, the use, disposal, and clean-up of polychlorinated biphenyls, contained in certain electrical equipment, are regulated under the federal Toxic Substances Control Act. PGE is also subject to the Comprehensive Environmental Response Compensation and Liability Act, commonly referred to as Superfund, which provides authority to the EPA to assert joint and several liability for investigation and remediation costs for designated Superfund sites. An investigation by the EPA that began in 1997 of a segment of the Willamette River in Oregon known as Portland Harbor, revealed significant contamination of river sediments and prompted the EPA to designate Portland Harbor as a Superfund site. The EPA has listed PGE among the more than one hundred Potentially Responsible Parties (PRPs) in this matter, as PGE historically owned or operated property near the river. For additional information regarding the EPA action on Portland Harbor, see Note 19, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data. PGE is subject to regulation by the United States Department of Energy (USDOE), which, under the Nuclear Waste Policy Act of 1982, is responsible for the permanent storage and disposal of spent nuclear fuel. PGE has contracted with the USDOE for permanent disposal of spent nuclear fuel from Trojan that is stored in the Independent Spent Fuel Storage Installation (ISFSI), an NRC-licensed interim dry storage facility that houses the fuel. The NRC approved the transfer of spent nuclear fuel from a spent fuel pool to the ISFSI where it is expected to remain until permanent off-site storage is available. Shipment of the spent nuclear fuel from the ISFSI to off-site storage is not expected to be completed prior to 2059. For additional information regarding this matter, see Trojan decommissioning activities in Note 8, Asset Retirement Obligations, in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data. Human Capital Management PGEs talent and culture are vital to its ability to execute its business strategy and realize continued success. Accordingly, the Company seeks to attract and retain a talented,

motivated, and diverse workforce and maintain a culture that reflects PGEs Guiding Behaviors, drive for performance, and commitment to acting with the highest levels of honesty, integrity, compliance, and safety. Employees and Collective Bargaining Agreements PGE had 2,873 employees in its workforce as of December 31, 2022, with 673 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers (IBEW). One agreement covers 610 employees, which expires March 2025, and the other covers 63 employees, which expires August 2027. The partnership with IBEW is key to a holistic labor relations approach. In addition, PGE utilizes independent contractors and temporary personnel to supplement its workforce. Competitive Pay and Benefits PGE is committed to pay equity among its employees and offers a wide range of market-competitive benefits, including comprehensive health and welfare benefits and a 401(k) retirement plan, designed to support the physical, mental, and financial well-being of its employees. Talent Development PGE provides a variety of training and development programs for employees, as well as tuition reimbursement for job-related coursework. PGE offers a mentorship program for all regular, non-represented PGE employees to help support their growth and development. The PGE Board of Directors oversees executive talent development with the assistance of the Nominating, Governance, and Sustainability Committee and the Compensation, Culture and Talent Committee in an effort to maximize the pool of internal candidates. At least annually, the Board conducts reviews of succession plans for senior management, which includes a review of the qualifications and development plans of potential internal candidates and diversity of the succession pipeline. The Compensation, Culture and Talent Committee regularly conducts more in-depth reviews of development plans for promising management talent. PGE conducts employee engagement surveys periodically to give employees the opportunity to share their perspectives and provide feedback. Survey results are shared with PGE management so that managers can take action towards improving the employee experience. Health and Safety PGE is committed to providing a safe and healthy place of business for employees, customers, and the public. Management has established an Executive Safety Council that has oversight of the Companys efforts to create a safe workplace. In addition, PGE provides various safety resources to its employees, such as safety manuals, trainings, and incident reporting tools that are all designed to incorporate safe practices into all daily activities and promote in all employees a sense of personal commitment, responsibility, and obligation regarding safety. PGE also has an Employee Assistance Program that provides free and confidential wellness counseling to all employees and their families. Diversity, Equity, and Inclusion PGE promotes an inclusive workforce through pay equity practices, racial equity training, and development opportunities for women and people of color to advance into management. Black, Indigenous, and People of Color comprise over 26% of its employees and nearly 26% of management. One third of its employees and management, including its CEO, are female. PGE also promotes diversity and economic development through its suppliers. The Companys supplier diversity program

provides an opportunity in all competitive bid events for qualified minority-owned, women-owned, disabled veteran-owned, and emerging small business suppliers. COVID-19 Since the beginning of the COVID-19 pandemic, PGE has taken steps to protect employees. The Company continues to prioritize the health and safety of its employees and be informed by federal, state and local officials to align its efforts with current information. Information about Executive Officers The following are PGEs current executive officers: ##TABLE_START Name Age Current Position and Previous Experience Year Appointed Officer James A. Ajello 69 Senior Vice President, Finance, Chief Financial Officer, Treasurer and Corporate Compliance Officer (January 2021 to present), Senior Advisor (November 2020 to December 2020), Executive Vice President and Chief Financial Officer at Hawaiian Electric Industries (January 2009 to April 2017 - retired), Senior Vice President, Business Development at Reliant Energy (January 2000 to January 2009), Managing Director, UBS Securities (January 1984 to August 1998). 2021 Larry N. Bekkedahl 61 Senior Vice President, Advanced Energy Delivery (July 2021 to present), Vice President, Grid Architecture, Integration and Systems Operations (January 2019 to July 2021), Vice President Transmission and Distribution (August 2014 to January 2019). Senior Vice President of Transmission Services at BPA (June 2012 to August 2014), Vice President of Engineering and Technical Services at BPA (2008 to June 2012). 2014 Nicholas G. Blosser 52 Vice President Public Affairs (August 2022 to present), Chief of Staff and Deputy Cabinet Secretary and Special Assistant to the President, Office of Cabinet Affairs at The White House (March 2021 to July 2022), Intergovernmental Affairs and State Lead, Biden-Harris Transition Team (November 2020-January 2021), Chief of Staff for Oregon Governor Kate Brown (February 2017 to November 2020), Co-Founder and CEO of Celilo Group Media, Inc. (January 2000 to February 2017) 2022 M. Angelica Espinosa 45 Vice President, General Counsel (March 2022 to present), Deputy General Counsel and Corporate Secretary (June 2021 to March 2022), Chief Risk Officer and Vice President of Safety and Compliance at Southern California Gas Company (January 2019 to June 2021), Vice President, Compliance Governance and Corporate Secretary at Sempra Energy (November 2016 to January 2019) 2022 Bradley Y. Jenkins 59 Vice President, Utility Operations (January 2019 to present), Vice President, Generation and Power Operations (October 2017 to January 2019), Vice President, Power Supply Generation (September 2015 to October 2017), General Manager, Diversified Plant Operations, (November 2013 to August 2015), Plant General Manager, Boardman (September 2012 to November 2013), Operations Manager, Boardman (March 2012 to September 2012). 2015 John T. Kochavatr 49 Vice President, Information Technology and Chief Information Officer (February 2018 to present). Senior Vice President and Chief Information Officer at SUEZ Water Technologies Solutions (formerly General Electric Water and Process Technologies) (October 2017 to January 2018), Chief Information Officer and Chief Digital Officer at General Electric Water and Process Technologies (November 2012 to September 2017). 2018 ##TABLE_END##TABLE_START Anne F. Mersereau 60 Vice President, Human Resources, Diversity, Equity and Inclusion (January 2016 to present),

Employee Services Manager (January 2014 to January 2016), Change Management Consultant (January 2012 to January 2014), Human Resources Business Partner (July 2009 to December 2011). 2016 Maria M. Pope 57 President (October 2017 to present) and Chief Executive Officer (January 2018 to present), Senior Vice President, Power Supply, Operations and Resource Strategy (March 2013 to December 2017), Senior Vice President, Finance, Chief Financial Officer and Treasurer (January 2009 to February 2013). Board director (January 2006 to December 2008). Vice President and Chief Financial Officer for Mentor Graphics Corporation (July 2007 to December 2008). 2009 Brett M. Sims 54 Vice President, Strategy, Regulation and Energy Supply (October 2020 to present), Senior Director of Strategy, Commercial and Regulatory Affairs (September 2017 to October 2020), Director of Origination, Structuring Resource Strategy (May 2001 to September 2017). 2020 ##TABLE_END ITEM 1A. RISK FACTORS. When evaluating PGE and any investment in its securities, investors should consider carefully the following risk factors and all other information contained in this Annual Report on Form 10-K and in the other documents that the Company files from time to time with the SEC. The events described in the risk factors could have material effects on PGEs business, financial condition, results of operations, or cash flows, or that materially adversely affect PGEs results and cause such results to differ materially from projected results. Risk and uncertainties not currently known to the Company or that are currently deemed to be immaterial may also harm PGE. If any of these risks occur, PGEs business, financial condition, results of operations, and/or cash flows could be materially adversely affected, and the trading prices of the Companys securities could substantially decline. BUSINESS AND OPERATIONAL RISKS The effects of unseasonable or severe weather and other natural phenomena can adversely affect the Companys financial condition and results of operations, and the effects of climate change could result in more intense, frequent, and extreme weather events. Weather conditions can adversely affect PGEs revenues and costs, impacting the Companys results of operations. Variations in temperatures can affect customer demand for electricity, with warmer-than-normal winter seasons or cooler-than-normal summer seasons reducing the demand for energy. Weather conditions are the dominant cause of usage variations from normal seasonal patterns, particularly for residential customers. Rapid increases in load requirements resulting from unexpected weather changes, particularly if coupled with transmission constraints, could adversely impact PGEs cost and ability to meet the energy needs of its customers. Conversely, rapid decreases in load requirements could result in the sale of excess energy at depressed market prices. Changes in the global and local climate could result in more intense, frequent, and extreme weather events such as ice and snowstorms, high wind, flooding, changes in regional rainfall and snowpack levels, high heat events, drought conditions, and increased risk of wildfires. These events may disrupt energy delivery, cause power outages, and damage the Companys facilities and transmission and distribution system. Such events could result in a reduction in revenue and an increase in additional costs to restore service, repair facilities, purchase power and fuel to serve PGE load, and

procure insurance related to such impacts. In response to more intense, frequent, and severe weather events, PGE may need to make additional investments in generation, transmission, and distribution assets to enhance reliability and resiliency. Severe weather may also require increased PGE personnel availability, which could result in increased operating expenses as well increased safety risk. In certain instances, PGE relies on mutual aid support to assist in the recovery from severe weather. Lack of availability of mutual aid support could result in increased time to restore services to customers as well as increased costs and decreased customer satisfaction. Wildfires of greater size and prevalence, such as those of a magnitude seen in Oregon in recent years, could negatively affect public safety, the resilience of the electric grid, customers demand for power and PGEs ability and cost to procure adequate power and fuel supplies to serve its customers, PGE s ability to access the wholesale energy market, PGEs ability to operate its generating facilities and transmission and distribution systems, PGEs costs to maintain, repair, and replace such facilities and systems, and recovery of costs. PGE may be unable to effectively implement a public safety power shutoff (PSPS) and de-energize its system in the event of heightened wildfire risk, or the PSPS may not be able to prevent a wildfire, which could lead to potential liability if energized systems are determined to be the cause of wildfires that result in harm. Capital investment and operating expenses related to this risk may not be recoverable through increases in customer prices. Cybersecurity attacks, data security breaches, physical attacks and security breaches, acts of terrorism, or other similar events that could disrupt PGEs operations, require significant expenditures, or result in claims against the Company. In the normal course of business, PGE collects, processes, and retains sensitive and confidential customer and employee information, as well as proprietary business information, and operates systems that directly impact the availability of electric power and the transmission of electric power in its service territory. PGE owns and operates generation, transmission, distribution, and other facilities that depend on information technology systems. A cyber-attack may cause large-scale disruption to the U.S. bulk power system or PGE operations and could target the Companys computer systems, software, or networks to achieve such disruption. Generation, transmission, and distribution facilities, in general, have been identified as potential targets of physical or cyber-attacks. In addition, physical attacks on transmission and distribution facilities have occurred in the United States. Despite the security measures in place, the Companys systems and assets, and those of third-party service providers, could be vulnerable to cybersecurity attacks, data security breaches, physical attacks and security breaches, acts of terrorism, or other similar events that could disrupt operations, cause damage to the Companys generation, transmission, or distribution facilities, impact reliability of the transmission and distribution system, information technology systems, inhibit the capability of equipment or systems to function as designed or expected, prevent service to customers or collection of revenues, or result in the release of sensitive or confidential customer, employee, or Company information. Such events could cause a shutdown of service, expose PGE to

liability, or cause reputational damage. In addition, the Company may be required to expend significant capital and other resources to protect against security breaches or to alleviate problems caused by security breaches. A breach of certain business systems could impact PGEs ability to initiate, authorize, process, record, and report financial information. The cost of repairing damage to PGEs facilities and infrastructure caused by acts of terrorism, and the loss of revenue if such events prevent PGE from providing utility service to its customers, could adversely impact its financial condition and results of operations. PGE maintains insurance coverage against some, but not all, potential losses resulting from these risks. However, insurance is limited in scope and subject to exceptions, and may not be adequate to protect the Company against liability in all cases and insurers may dispute or be unable to perform their obligations to the Company, or may not be available at rates that are commercially reasonable. Natural or human-caused disasters and other risks could damage the Companys facilities and disrupt delivery of electricity resulting in significant property loss, repair costs, and reduced customer satisfaction. PGE has exposure to natural and human-caused disasters and other risks, including, but not limited to, a pandemic such as COVID-19, earthquake, accidents, equipment failure, acts of terrorism, acts of vandalism, computer system outages and other events. Such events, which may be amplified by the fact that PGEs business activities are concentrated in one region, could disrupt PGE operations, damage PGE facilities and systems, interrupt the delivery of electricity, increase repair and service restoration expenses, reduce revenues, cause the release of harmful materials, cause fires or flooding, and subject the Company to liability. Such events, if repeated or prolonged, can also affect customer satisfaction and the level of regulatory oversight. Electric utility operations may pose risk to public and workers safety. The operation of electric generation, transmission, and distribution infrastructure involves inherent risks, including breakdown or failure of equipment, motor vehicle accidents, fires involving the utilitys equipment, dam failure at company-owned hydroelectric facilities, public and worker safety, human contact with energized equipment, and operator error. A portion of the Companys operations relies on Company- or third party-owned natural gas transmission and distribution infrastructure and involves inherent risks, such as leaks, explosions, mechanical problems, and worker and public safety. These risks could cause significant harm to workers and the public including loss of human life, significant damage to property, adverse impacts on the environment and impairment of PGEs operations, all of which could result in financial losses that would have a material adverse effect on the Companys results of operations and financial condition. PGE is also required to comply with new and changing regulatory standards involving safety compliance. The cost to comply with such requirements could be significant, and failure to meet these regulatory standards could result in substantial fines. The inability to attract and retain a qualified workforce and to maintain satisfactory collective bargaining agreements without prolonged labor disruptions, may adversely affect PGEs results of operations. PGEs workforce includes a diverse mix of skilled professional, managerial, and technical employees, including employees represented

under collective bargaining agreements. Workforce management risks include the risk of retaining key employees, turnover due to demographic challenges as employees approach retirement age, and turnover due to macroeconomic trends such as the impacts of inflation on pensions and other retirement funding. PGE faces competition for employees within the industry and in local geographies. The Company faces the risk of labor disruption due to the outcomes of labor negotiations or the possibility that employees not currently subject to collective bargaining agreements may organize. PGE relies on a contracted workforce for specific business purposes, and may experience increased costs or inability to find contracted workforce, which may result in a negative impact on operations as well as financial impact. The construction of new facilities and the modifications or replacements of existing facilities, is subject to risks that could result in the disallowance of certain costs for recovery in customer prices or higher operating costs. Long-term increases in both the number of customers and demand for energy will require continued expansion and upgrade of PGEs generation, transmission, and distribution systems. Construction of new facilities and modifications or replacements of existing facilities could be affected by factors such as unanticipated delays and cost increases, including supply chain disruption and cost inflation, availability of skilled workforce, increases in interest rates, failure of counterparties to perform under agreements, and the failure to obtain, or delay in obtaining, necessary permits from state or federal agencies or tribal entities. Delays and cost increases could result in failure to complete the projects or the abandonment of capital projects, which could eliminate or impair PGEs ability to recover related costs in the rate determination process. In addition, failure to complete construction projects according to specifications could result in reduced plant efficiency, equipment failure, and plant performance that falls below expected levels, which could increase operating costs. REGULATORY, LEGAL, AND COMPLIANCE RISKS PGE is subject to extensive price regulation and relies on recovery of costs, the uncertainty of which affect the Companys operations and costs. PGE is subject to ongoing regulation by the FERC, the OPUC and by certain federal, state, and local authorities under environmental, permitting, and other laws. Such regulation significantly influences the Companys operating environment and affects many aspects of its business. The Company cannot predict with certainty the future course of such changes or the ultimate effect that they might have on its business, and such changes could delay or adversely affect business planning and transactions and substantially increase the Companys costs. OPUC regulates the prices that PGE charges, which is a major factor in determining the Companys operating income, financial position, liquidity, and credit ratings. As a general matter, PGE relies on customer prices to recover most of the costs incurred in connection with the operation of its business, including, among other things, costs related to capital projects (such as the construction of new facilities or the modification of existing facilities), the costs of compliance with legislative and regulatory requirements (including environmental laws), and the costs of damage from storms and other natural disasters. Regulators may deny recovery of costs it considers imprudently incurred. Although the

OPUC is required to establish customer prices that are fair, just, and reasonable, it has significant discretion in the interpretation of this standard. PGE attempts to manage its costs at levels consistent with OPUC-approved prices. However, if the Company is unable to do so, or if such cost management results in increased operational risk, the Companys financial and operating results could be adversely affected. PGE is subject to various legal and regulatory proceedings, the outcome of which is uncertain, and resolution unfavorable to PGE could adversely affect its results of operations, financial condition, or cash flows. In the normal course of its business, PGE is subject to regulatory proceedings, lawsuits, claims, and other matters, which could result in adverse judgments, settlements, fines, penalties, injunctions, or other relief. Such matters include governmental policies, legislative action, and regulatory audits, investigations, and actions, including those of the FERC and OPUC with respect to allowed rates of return, financings, electricity pricing and price structures, acquisition and disposal of facilities and other assets, construction and operation of plant facilities, transmission of electricity, recovery of power costs, operating expenses, deferrals, timely recovery of costs and capital investments, and current or prospective wholesale and retail competition. These matters are subject to many uncertainties, the ultimate outcome of which management cannot predict. The final resolution of certain matters in which PGE is involved could result in disallowance of operating expenses previously deferred or could require that the Company incur expenditures over an extended period and in a range of amounts that could have an adverse effect on its cash flows and results of operations. Similarly, the terms of resolution could require the Company to change its business practices and procedures, which could also have an adverse effect on its cash flows, financial position, or results of operations. New laws, changes in legal precedent, or novel interpretations of existing regulations could also result in adverse effects on cash flows and results of operations. There are certain pending legal and regulatory proceedings that may have an adverse effect on results of operations and cash flows for future reporting periods. For additional information, see Item 3.Legal Proceedings, Regulatory Matters within the Overview of Item 7. Managements Discussion and Analysis of Financial Condition and Results of Operations, and Note 19, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data. Compliance with environmental laws and regulations may result in capital expenditures, increased operating costs and various liabilities, and adverse impact on the Companys results of operations. PGE is subject to various environmental laws, regulations, and other standards including federal, state and local environmental statutes, rules and regulations relating to air quality, water quality and usage, soil quality, emissions of greenhouse gases (GHG) such as carbon dioxide, waste management, hazardous wastes, fish, avian and other wildlife mortality and habitat protection, historical artifact preservation, natural resources, health, and safety. Compliance with such laws and regulations could, among other things, prevent or delay the development of power generation and transmission and distribution facilities, restrict output of facilities, limit the use of fuels required for power generation,

require additional pollution control equipment, require investment in non-emitting resources, and otherwise increase costs and increase capital expenditures. A portion of PGEs total system load is supplied with power generated from hydroelectric and wind generating resources. Operation of these facilities is subject to regulation related to the protection of fish and wildlife. Changes to the listing of various plants and species of fish, birds, and other wildlife as threatened or endangered could result in increased mitigation activities, which could have a material impact on PGEs financial condition and results of operations. Salmon recovery plans could include further major operational changes to the regions hydroelectric projects, including those owned by PGE and those from which the Company purchases power under long-term contracts. In addition, laws relating to the protection of migratory birds and other wildlife could impact the development and operation of transmission and distribution lines and wind projects. Also, new interpretations of existing laws and regulations could be adopted or become applicable to such facilities, which could further increase required expenditures for salmon recovery and endangered species protection and reduce the availability of hydroelectric or wind generating resources to meet the Companys energy requirements. Compliance with any new or additional GHG emissions reduction requirements could require PGE to incur significant expenditures, including those related to carbon capture and sequestration technology, purchase of emission allowances and offsets, fuel switching, and the retirement or replacement of high-emitting generation facilities with non-emitting facilities. The cost to comply with potential GHG emissions reduction requirements is subject to significant uncertainties, including those related to: the timing of the implementation of emissions reduction rules; required levels of emissions reductions; requirements with respect to the allocation of emissions allowances; the maturation, regulation, and commercialization of carbon capture, sequestration, and storage technology; and PGEs compliance alternatives. Although the Company cannot currently estimate the effect of future laws and regulations on its results of operations, financial condition, or cash flows, the costs of compliance with such legislation or regulations could be material. Changes in tax laws may have an adverse impact on the Companys financial position, results of operations, and cash flows. PGE makes judgments and interpretations about the application of tax law when determining the provision for taxes. Such judgments include the timing and probability of recognition of income, deductions, and tax credits, which are subject to challenge by taxing authorities. Additionally, treatment of tax benefits and costs for ratemaking purposes could be different than what the Company anticipates or requests from the State regulatory commission, which could have a negative effect on the Companys financial condition and results of operations. PGE owns and operates renewable generating facilities, which generate federal production tax credits (PTCs) that PGE uses to reduce its federal tax obligations. The amount of PTCs earned depends on the level of electricity output generated and the applicable tax credit rate. A variety of operating and economic parameters, including adverse weather conditions and equipment reliability, could significantly reduce the PTCs generated by the Companys wind facilities resulting

in a material adverse impact on PGEs financial condition and results of operations. These PTCs generate tax credit carryforwards that the Company plans to utilize in the future to reduce income tax obligations. If PGE cannot generate enough taxable income in the future to utilize all of the tax credit carryforwards before the credits expire, the Company may incur material charges to earnings. ECONOMIC, FINANCIAL, AND MARKET RISKS A decrease in customer demand for electricity may negatively impact PGEs business. Unfavorable economic conditions in Oregon, such as, for example, increased inflation, may result in reduced demand for electricity and impair the financial stability of PGEs customers. Such reductions in demand could adversely affect PGEs results of operations and cash flows. Economic conditions could also result in an increased level of uncollectible customer accounts and cause the Companys vendors and service providers to experience cash flow problems and be unable to perform under existing or future contracts. Customer demand could also be negatively impacted by PGEs ability to attract and retain customers, mandated energy efficiency measures, demand side management programs, potential formation of community choice aggregation programs, distributed generation resources, and economic and demographic conditions, such as population changes, job and income growth, new construction, new business formation and the overall level of economic activity. Development, improvement, and adoption of technological advances could lead to declines in energy use per customer. Some or all of these factors could impact the demand for electricity. The decline in revenues due to decreased customer demand for electricity may increase customer prices for remaining customers, as PGEs revenue requirement is designed to cover its fixed utility operating expenses. Increased customer prices could further reduce customer demand for electricity and strain PGEs ability to attract and retain customers. The loss of customers, the inability to replace those customers with new customers, and the decrease in demand for electricity could negatively impact PGEs financial condition and results of operations. Capital and credit market conditions could adversely affect the Companys access to capital, cost of capital, and ability to execute its strategic plan. Access to capital and credit markets is important to PGEs ability to operate. The Company expects to issue debt and equity securities, as necessary, to fund its future capital requirements. Volatility of interest rates could negatively impact PGEs cost of debt and results of operations. In addition, contractual commitments and regulatory requirements may limit the Companys ability to delay or terminate certain projects. If the capital and credit market conditions in the United States and other parts of the world deteriorate, the Companys future cost of debt and equity capital, as well as access to capital markets, could be adversely affected. In addition, sales or issuances of substantial amounts of PGEs common stock in the public market, including upon settlement of the forward sale agreements entered into in 2022, could cause the market price of PGEs common stock to decline. This could impair the Companys ability to raise additional capital through the sale of equity securities. Future sales or issuances of common stock or other equity-related securities could be dilutive to holders of common stock and could adversely affect their voting and other rights and

economic interests. PGE expects to raise additional capital in the future. PGE may raise additional funds through public or private equity or debt offerings or other financings, as well as additional borrowings under existing credit facilities. Any new debt financing entered into may involve covenants that restrict operations more than PGEs current outstanding debt and credit facilities. These restrictive covenants could include limitations on additional borrowings, specific restrictions on the use of assets, and prohibitions or limitations on the Companys ability to create liens, pay dividends, receive distributions from subsidiaries, redeem or repurchase stock or make investments. These factors could hinder the Companys access to capital markets and limit or delay the ability to carry out the Companys capital expenditure plan or pursue other opportunities beyond the current capital expenditure plan. The declaration of future dividends is at the discretion of the Board of Directors and is not guaranteed and, in some circumstances, the payment of dividends may be limited by the terms of PGEs debt instruments. PGE has historically paid regular quarterly dividends on common stock. However, the declaration of dividends is at the discretion of PGEs Board of Directors and is not guaranteed. The amount of common stock dividends, if any, will depend upon results of operations and financial condition, future capital expenditures and investments, the rights of holders of any outstanding shares of preferred stock, and other factors that the Board of Directors considers relevant. In addition, the terms of the Companys debt instruments may limit the payment of dividends. Under the Indenture of Mortgage and Deed of Trust, dated July 1, 1945, as amended and supplemented to date, between PGE and Wells Fargo Bank, National Association, so long as any of the first mortgage bonds are outstanding, the Company may not pay or declare dividends (other than stock dividends) on common stock or purchase or retire for a consideration (other than in exchange for other shares of PGEs capital stock or the proceeds from the sale of other shares of capital stock) any shares of capital stock of any class, if the aggregate amount distributed or expended after December 31, 1944 would exceed the aggregate amount of PGEs net income, as adjusted, available for dividends on common stock accumulated after December 31, 1944. At December 31, 2022, $399 million of accumulated net income was available for payment of dividends under this provision. Adverse changes in PGEs credit ratings could negatively affect its access to the capital markets and its cost of borrowed funds. Credit rating agencies routinely evaluate the Company, and their ratings of long-term and short-term debt are based on a number of factors, including the perceived supportiveness of the regulatory environment affecting the utility operations, the Companys cash generating capability, level of indebtedness, overall financial strength, the status of certain capital projects, as well as factors beyond PGEs control, such as tax reform, the state of the economy and industry generally. A ratings downgrade could increase fees on PGEs syndicated unsecured revolving credit facility, commercial paper program, and letter of credit facilities, increasing the cost of funding day-to-day working capital requirements, and could also result in higher interest rates on future long-term debt. A ratings downgrade could also restrict the Companys access to the commercial paper market, a principal source of short-term financing, or

result in higher interest costs. In addition, if Moodys Investors Service (Moodys) and/or SP Global Ratings (SP) reduce their rating on PGEs unsecured debt to below investment grade, the Company could be subject to requests by certain wholesale counterparties to post additional performance assurance collateral, which could have an adverse effect on the Companys liquidity and ability to participate in the wholesale markets. Under certain circumstances, banks participating in PGEs syndicated unsecured revolving credit facility could decline to fund advances requested by the Company or could withdraw from participation in the credit facility, which could adversely affect PGEs liquidity. PGE currently has a syndicated unsecured revolving credit facility with several banks for an aggregate amount of $650 million. The revolving credit facility provides a primary source of liquidity and may be used to supplement operating cash flow and as backup for commercial paper borrowings. The revolving credit facility represents commitments by the participating banks to make loans and, in certain cases, to issue letters of credit. The Company is required to make certain representations to the banks each time it requests an advance under the credit facility. However, in the event of a material adverse change in the business, financial condition, or results of operations of PGE, the Company may not be able to make such representations, in which case the banks would not be required to lend. PGE is also subject to the risk that one or more of the participating banks may default on their obligation to make loans under the credit facility. Adverse capital market performance could result in reductions in the fair value of benefit plan assets and increase the Companys liabilities related to such plans. Sustained declines in the fair value of the plans assets could result in significant increases in funding requirements, which could adversely affect PGEs liquidity and results of operations. Performance of the capital markets affects the value of assets that are held in trust to satisfy future obligations under PGEs defined benefit pension and other postretirement plans. Sustained adverse market performance could result in lower rates of return for these assets than projected by the Company and could increase PGEs funding requirements related to the plans. Additionally, changes in interest rates affect PGEs liabilities under the plans. As interest rates decrease, the Companys liabilities increase, potentially requiring additional funding. Performance of the capital markets also affects the fair value of assets that are held in trust to satisfy future obligations under the Companys non-qualified employee benefit plans, which include deferred compensation plans. As changes in the fair value of these assets are recorded in current earnings, decreases can adversely affect the Companys operating results. In addition, such decreases can require that PGE make additional payments to satisfy its obligations under these plans. The volatility of market prices for power and natural gas could adversely affect PGEs costs and ability to manage its energy supply, which could negatively impact the Companys liquidity and results of operations. As part of its normal business operations, PGE purchases and sells power and natural gas in the open market under short- and long-term contracts, which may specify variable prices or volumes. Market prices for power and natural gas are influenced primarily by factors related to supply and demand. These factors

generally include the adequacy of generating capacity, scheduled and unscheduled outages of generating facilities, hydroelectric and wind generation levels, prices and availability of fuel sources for generation, disruptions or constraints to transmission facilities, weather conditions, economic growth, and changes in technology. Volatility in these markets can affect the availability, price, and demand for power and natural gas. Disruption in power and natural gas markets could result in a deterioration of market liquidity, increase the risk of counterparty default, affect regulatory and legislative processes in unpredictable ways, affect wholesale power prices, and impair PGEs ability to manage its energy portfolio. Changes in power and natural gas prices can also affect the fair value of derivative instruments and cash requirements to purchase power and natural gas. If power and natural gas prices decrease from those contained in the Companys existing purchased power and natural gas agreements, PGE may be required to provide increased collateral, which could adversely affect the Companys liquidity. Conversely, if power and natural gas prices rise, especially during periods when the Company requires greater-than-expected volumes that must be purchased at market or short-term prices, PGE could incur greater costs than originally estimated. PGEs contract positions are not fully hedged against commodity prices, and hedges or other risk mitigations may not protect against significant losses. The risk of volatility in power costs is partially mitigated through the AUT and the PCAM. Application of the PCAM requires that PGE absorb certain power cost increases before the Company is allowed to recover any amount from customers. Accordingly, the PCAM is expected to only partially mitigate the potentially adverse financial impacts of forced generating plant outages, reduced hydro and wind availability, interruptions in fuel supplies, and volatile wholesale energy prices. PGE has put in place risk management policies, procedures, and controls to identify, quantify, and manage risk, however, these systems, processes, tools, and controls may not prevent material losses. Risk management procedures may not always be followed as intended, may not operate as designed, or may not identify all potential risks, including, without limitation, severe weather or employee misconduct. There is no assurance that PGEs risk management procedures will be effective in preventing or mitigating losses, and could have a material adverse effect on the Companys results of operation and financial condition. Reduced river flows, unfavorable wind conditions, and forced outages at generating and battery storage facilities can increase the cost of power required to serve customers. The Company could be required to replace energy expected from these sources with higher cost power from other facilities or with wholesale market purchases, which could have an adverse effect on results of operations. PGE derives a significant portion of its power supply from its own hydroelectric facilities and long-term purchase contracts with certain public utility districts in the state of Washington. Regional rainfall and snowpack levels affect river flows and the resulting amount of energy generated by these facilities. Shortfalls in energy expected from lower cost hydroelectric generating resources would require increased energy from the Companys other generating resources and/or power purchases in the wholesale market, which could have an adverse effect on results of

operations. PGE also derives a portion of its power supply from wind generating resources, for which the output is dependent upon wind conditions. Unfavorable wind conditions could require increased reliance on power from the Companys thermal generating resources or power purchases in the wholesale market, both of which could have an adverse effect on results of operations. Forced outages at generating facilities and battery storage facilities, both PGE-owned or under purchased power agreements, could result in power costs greater than those included in customer prices, in addition to increased repair and maintenance costs. Although the application of the PCAM could help mitigate adverse financial effects from any decrease in power supply, full recovery of any increase in power costs is not assured. Inability to fully recover such costs in future prices could have a negative impact on the Companys results of operations, as well as a reduction in renewable energy credits and loss of PTCs related to wind generating resources. The capacity provided by the Companys generating resources and third-party purchased power may not be sufficient to meet its customers energy demand requirements. PGE meets its customers energy demand requirements based on capacity obtained from its generating facilities and third-party power purchase agreements. The Company continuously evaluates how much capacity it will need to meet reasonably expected demands of customers and provide reasonable reserves. PGE is also required to file Integrated Resource Plans with the OPUC that detail the Companys plan to meet the future energy and capacity needs of its customers through a least-cost, least-risk combination of energy generation and demand reduction, while also aggressively reducing GHG emissions from the power supply. If the capacity provided by the Companys generating facilities and purchased power is not adequate to meet customers energy demands, PGE may be required to purchase more power from third parties, invest in acquiring additional generating or battery storage facilities, or invest in extending the operating life of existing generating assets. Any failure to obtain adequate capacity to meet customers energy demand requirements could increase its costs and negatively impact PGEs customer satisfaction, all of which could have an adverse impact on PGEs business and results of operations. Advances in energy technology could make PGEs business less competitive. A basic premise of PGEs business as a vertically integrated utility is the ability to produce electricity at competitive prices due to economies of scale. Furthermore, a key component of PGEs growth is its ability to construct, own, and operate facilities. Many companies and organizations conduct research and development activities to seek improvements in alternative technologies and distributed generation. Advancements in and creation of new technologies could include fuel cells and micro turbines, wind turbines, photovoltaic solar cells, distributed generation, nuclear energy, hydrogen, ongoing customer energy efficiency, two-way grid enabling customer-owned generation, and advances in batteries or energy storage. It is possible that advances in such technologies, or other current technologies, will reduce the cost of alternative methods of electricity production or storage to a level that is equal to or below that of existing methods. The electricity industry is undergoing significant change, including increased deployment of distributed

energy resources, technological advancements as described above, and political and regulatory developments. Electric utilities are experiencing increasing deployment of distributed energy resources, such as solar generation, energy storage, energy efficiency and demand response technologies. The deployment of these technologies supports PGEs decarbonization goals. The growth of new technologies will require modernization of the electric distribution grid to, among other things, accommodate increasing two-way flows of electricity and increase the grids capacity to interconnect these resources. A higher penetration of distributed energy resources may result in decreased customer demand, or may have impacts on grid reliability. Increased distributed energy resources and renewable energy resources will require new and sustained investments in grid modernization and transmission. If all such costs are not recoverable in rates, PGE could experience material increases in its commodity costs, which could impact PGEs results of operations, financial condition, or cash flows. It is also possible that alternative generation or storage resources are mandated, subsidized, or encouraged through legislation or regulation or otherwise are economically competitive and added to the available generation supply. Competitors may not be subject to the same operating, regulatory and financial requirements that the Company is, potentially causing a substantial competitive disadvantage for PGE. Changes in public policy, such as new tax incentives that PGE cannot take advantage of or efforts to deregulate the utility industry, could provide an advantage to competitors. Such alternative resources and regulatory or legislative actions could displace higher marginal cost generating units or make PGE less competitive in constructing, owning, and operating such facilities. Such a development could limit the Companys future growth opportunities and limit growth in demand for PGEs electric service. Changes in market conditions and environmental laws and regulations could negatively impact PGEs non-utility real estate investments. PGE owns, through a wholly owned subsidiary, its corporate headquarters building located in Portland, Oregon. A significant change in real estate values could adversely affect PGEs results of operations. PGE also owns unregulated properties that are currently or previously leased to third parties and located adjacent to PGEs T.W. Sullivan hydro generating facility. PGE has recorded a non-utility asset retirement obligation (ARO) for this site related to assets that are no longer in service. Significant changes in estimates for this non-utility ARO due to changes in environmental laws or regulations could adversely affect PGEs results of operations. Rapidly changing stakeholder expectations and standards with respect to PGEs environmental, social, and governance (ESG) programs could result in increased costs and exposure to incremental risk. Investors, lenders, rating agencies, customers, regulators, employees, and other stakeholders are increasing their focus on evaluating companies as corporate citizens based on their ESG programs and metrics. Based on PGEs ESG profile, investors and lenders may elect to increase their required returns on capital offered to the Company, reallocate capital, or not commit capital as a result of their assessment of the Companys ESG profile. Such actions by investors and lenders could increase PGEs cost of, or access to, capital and financing. PGE is

committed to the success of its ESG programs; however, if the Company fails to adapt or execute on its ESG strategies, or is perceived to have failed in addressing stakeholder ESG expectations or standards, which continue to evolve, PGE may suffer reputational damage, which could have a material adverse effect on its business, results of operations, and financial condition. Additionally, the cost of implementing and complying with such ESG programs could be material. Actions of activist shareholders could have a negative impact on PGEs business. Actions of activist shareholders, which can take many forms and arise in a variety of situations, could include engaging in proxy solicitations, advancing shareholder proposals, or otherwise attempting to effect changes and assert influence on the Companys board of directors and management. Dealing with such actions could result in substantial costs and divert managements and the Companys boards attention and resources from PGEs business and execution of its strategy. Such shareholder activism could give rise to perceived uncertainties regarding PGEs future, adversely affecting PGEs business opportunities, ability to access capital markets, relationships with its customers and employees, and make it more difficult to attract and retain a qualified workforce. Any such actions could have a material adverse effect on the Companys financial condition and results of operations and could cause significant fluctuations in the trading prices of its common stock based on market perceptions or other factors. PGEs business activities are concentrated in one region and future performance may be affected by events and factors unique to Oregon or the region. The Companys industry and geographic concentrations may increase exposure to risks arising from regional regulation or legislation, such as legislative action related to carbon emissions. These concentrations may also increase exposure to credit and operational risks due to counterparties, suppliers, and customers being similarly affected by changing conditions.

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ITEM 1. BUSINESS. General Portland General Electric Company (PGE or the Company), a vertically-integrated electric utility with corporate headquarters located in Portland, Oregon, is engaged in the generation, wholesale purchase, transmission, distribution, and retail sale of electricity in the state of Oregon (State). The Company operates as a cost-based, regulated electric utility with revenue requirements and customer prices determined based on the forecasted cost to serve retail customers and a reasonable rate of return as determined by the Public Utility Commission of Oregon (OPUC). PGE meets its retail load requirement with both Company-owned generation and power purchased in the wholesale market. The Company participates in the wholesale market through the purchase and sale of electricity and natural gas in an effort to obtain reasonably-priced power to serve its retail customers. PGE is committed to developing products and service offerings for the benefit of retail and wholesale customers. PGE, incorporated in 1930, is publicly-owned, with its common stock listed on the New York Stock Exchange (NYSE). The Company operates as a single business segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis. The Company owns unregulated, non-utility real estate comprised primarily of PGEs corporate headquarters. PGEs State-approved service area allocation of four thousand square miles is located entirely within Oregon and includes 51 incorporated cities. During 2022, the Company added nine thousand customers, and as of December 31, 2022, served a total of 926 thousand retail customers. Available Information PGEs periodic and current reports, and amendments to those reports, are available and may be accessed free of charge through the Investors section of the Companys website at PortlandGeneral.com as soon as reasonably practicable after the reports are electronically filed with, or furnished to, the United States Securities and Exchange Commission (SEC). It is not intended that PGEs website and the information contained therein or connected thereto be incorporated into this Annual Report on Form 10-K. Regulation Federal and State regulation each have a significant influence on PGEs business operations. In addition to the agencies and activities discussed below, the Company is subject to regulation by certain environmental agencies, as described in the Environmental Matters section in this Item 1. Federal Regulation Several federal agencies, including the Federal Energy Regulatory Commission (FERC), the U.S. Department of Transportations Pipeline and Hazardous Materials Safety Administration (PHMSA), and the Nuclear Regulatory Commission (NRC), have regulatory authority over certain of PGEs operations and activities, as described in the discussion that follows. PGE is a licensee, a public utility, and a user, owner, and operator of the bulk power system, as those terms are defined in the Federal Power Act (FPA). As such, the Company is subject to regulation by the FERC in matters related to wholesale energy activities, transmission services, reliability and cybersecurity standards, natural gas pipelines, hydroelectric projects, accounting policies and practices, short-term debt issuances, and certain other matters. Wholesale Energy PGE has authority under its FERC Market-Based Rates tariff to charge market-based rates for wholesale energy sales in all markets in which it sells electricity except in its own Balancing Authority Area (BAA). The BAA is the area in which PGE is responsible for balancing customer demand with electricity supply, in real time, and the tariff exception within PGEs BAA does not have a material impact on the Company. Transmission PGE offers wholesale electricity transmission service pursuant to its Open Access Transmission Tariff (OATT), which contains rates, terms, and conditions of service, as filed with, and approved by, the FERC. Reliability and Cybersecurity Standards The FERC has adopted mandatory reliability standards for owners, users, and operators of the bulk power system. Such standards, which are applicable to PGE, were developed by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC), which have responsibility for compliance and enforcement of these standards, and are intended to help protect critical cyber and physical assets used to support reliable operations. Natural Gas Pipelines The FERC has authority in matters related to the construction, operation, extension, enlargement, safety, and abandonment of jurisdictional interstate natural gas pipeline facilities, as well as transportation rates and accounting for interstate natural gas commerce. PGE is subject to such authority as the Company has a 79.5% ownership interest in the Kelso-Beaver (KB) Pipeline, a 17-mile, 20-inch diameter, interstate pipeline that provides natural gas to

Port Westward Unit 1 (PW1), Port Westward Unit 2 (PW2), and Beaver, the Companys natural gas-fired generating plants located near Clatskanie, Oregon, to the North Mist storage facility (owned and operated by a local natural gas distribution company), and to one additional local delivery point that serves a manufacturing concern. As the operator of record of the KB Pipeline, PGE is subject to the requirements and regulations enacted under the Pipeline Safety Laws administered by the PHMSA, which include safety and operator qualification standards in addition to public awareness requirements. Hydroelectric Licensing As required under the FPA, PGE holds FERC licenses for all Company-owned and operated hydroelectric generating plants. The FERC license process includes an extensive public review process that involves the consideration of numerous natural resource issues and environmental conditions. For additional information, see the Environmental Matters section in this Item 1. and the Generating Facilities section in Item 2.Properties. Accounting Policies and Practices PGE prepares periodic and current reports in accordance with accounting principles generally accepted in the United States of America (GAAP). In addition, the Company prepares, pursuant to applicable provisions of the FPA, financial statements in accordance with the accounting requirements of the FERC, as set forth in its applicable Uniform System of Accounts and published accounting releases. Such financial statements are included in annual and quarterly reports filed with the FERC. Short-term Debt Pursuant to applicable provisions of the FPA and FERC regulations, regulated public utilities are required to obtain FERC approval to issue certain securities. For additional information on the Companys Short-term Debt, see Short-term Debt in the Debt and Equity section of Liquidity and Capital Resources in Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Spent Fuel Storage The NRC regulates the licensing and decommissioning of nuclear power plants, including PGEs decommissioned Trojan nuclear power plant (Trojan), which was closed in 1993. For additional information on spent nuclear fuel storage activities, see Note 8, Asset Retirement Obligations in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data and Hazardous Material in the Environmental Matters section of this Item 1. State Regulation PGE is subject to the jurisdiction of the OPUC, which reviews and approves the Companys retail prices and reviews the Companys generation and transmission resource acquisition plans, pursuant to a biennial integrated resource planning process. The OPUC regulates the issuance of securities, prescribes accounting policies and practices, regulates the sale of utility assets, reviews transactions with affiliated companies, and has jurisdiction over the acquisition of, or exertion of substantial influence over, public utilities. Retail customer prices are determined through formal public proceedings that generally include testimony by participating parties, discovery, public hearings, and the issuance of a final order by the OPUC. Participants in such proceedings may include PGE, OPUC staff, and intervenors representing PGE customer groups, as well as other interested parties. The following lists the more significant regulatory mechanisms and proceedings under which customer prices are determined: General Rate Cases . PGE periodically

evaluates the need to update its retail electric price structure as part of a comprehensive general rate case process that reflects revenue requirements based on a forecasted test year. The OPUC authorizes the Companys debt-to-equity capital structure, return on equity, overall rate of return, and customer prices. Annual Power Cost Updates . The OPUC has approved an Annual Power Cost Update Tariff (AUT) by which PGE can adjust retail customer prices annually to reflect forecasted changes in the Companys net variable power costs (NVPC). NVPC consists of the cost of power purchased and fuel used to generate electricity, as well as the cost of settled electric and natural gas financial contracts (all classified as Purchased power and fuel expense in the Companys consolidated statements of income) and is net of wholesale revenues, which are classified in the consolidated statements of income as Revenues, net. The OPUC has also authorized a Power Cost Adjustment Mechanism (PCAM), under which PGE may share with customers a portion of actual cost variances associated with NVPC. Renewable Energy. The State has a Renewable Portfolio Standard (RPS) that requires PGE to serve a portion of its retail load with renewable resources. In conjunction with the RPS, the State established a Renewable Adjustment Clause (RAC) mechanism that allows for the recovery in retail customer prices, outside of a general rate case, of prudently incurred costs to comply with the RPS. In 2016, the State also passed Oregon Senate Bill (SB) 1547, a law referred to as the Oregon Clean Electricity and Coal Transition Plan, which, among its provisions, increased the RPS percentages in certain future years and required the elimination of coal from Oregon utility customers energy supply. For further information on SB 1547, see RPS standards and other laws in the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. During 2021, the State legislature passed House Bill (HB) 2021, which establishes clean energy targets and sets out a framework that includes, among other things, the development and submittal of clean energy plans for investor-owned utilities, including PGE, and electric service suppliers in the State. The targets are an 80% reduction in greenhouse gas (GHG) emissions by 2030, 90% by 2035, and 100% by 2040 and every year thereafter. For further information on HB 2021 and the baseline to which the target reductions apply, see HB 2021 in the Laws and Regulations portion of the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Regulatory Accounting PGE prepares financial statements in accordance with GAAP and, as a regulated public utility, the effects of rate regulation are reflected in its financial statements. GAAP provides for the deferral, as regulatory assets, of certain actual or estimated costs that would otherwise be charged to expense, based on expected recovery from customers in future prices. Likewise, certain actual or anticipated credits that would otherwise be recognized as revenue or reduce expense can be deferred as regulatory liabilities, based on expected future credits or refunds to customers. PGE records regulatory assets or liabilities if it is probable that they will be reflected in future prices, based on regulatory orders or other available evidence. The Company periodically assesses the applicability of regulatory accounting to its business, considering both the current and

anticipated future regulatory environment and related accounting guidance . For additional information, see Regulatory Assets and Liabilities in Note 2, Summary of Significant Accounting Policies, and Note 7, Regulatory Assets and Liabilities, in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data. Customers and Revenues PGE generates revenue primarily through the sale and delivery of electricity to retail customers located exclusively in Oregon. In addition, the Company distributes power to customers that choose to purchase their energy from an Electricity Service Supplier (ESS). Although the Company includes such Direct Access customers in its customer counts and energy delivered to such commercial and industrial customers in its total retail energy deliveries, retail revenues include only delivery charges and applicable transition adjustments for these Direct Access customers, as the customers purchase energy directly from the ESSs. The Company conducts retail electric operations within its State-approved service territory and competes with ESSs to supply certain commercial and industrial customer energy needs. In addition, PGE competes with the local natural gas distribution company for the energy needs of residential and commercial space heating, water heating, and appliances. Energy efficiency, conservation measures, and the advancement of distributed generation, including rooftop solar, and storage resources also have an influence on customer demand. Retail Revenues Retail customers are classified as residential, commercial, or industrial, with no single customer representing more than 8% of PGEs total retail revenues or 13% of total retail deliveries. PGEs Retail revenues, retail energy deliveries, and average number of retail customers consist of the following: ##TABLE_START Years Ended December 31, 2022 2021 2020 Retail revenues (1) (dollars in millions): Residential $ 1,158 52 % $ 1,118 54 % $ 1,030 53 % Commercial 735 33 708 34 634 33 Industrial 312 14 279 13 246 13 Subtotal 2,205 99 2,105 101 1,910 99 Alternative revenue programs, net of amortization 11 1 (29) (1) (6) Other accrued revenues, net (2) 7 2 28 1 Total retail revenues $ 2,223 100 % $ 2,078 100 % $ 1,932 100 % Retail energy deliveries (3) (MWh in thousands): Residential 8,088 38 % 7,978 39 % 7,756 40 % Commercial 7,198 34 7,193 35 6,855 35 Industrial 5,945 28 5,361 26 4,932 25 Total retail energy deliveries 21,231 100 % 20,532 100 % 19,543 100 % Average number of retail customers: Residential 809,573 88 % 800,372 88 % 791,119 88 % Commercial 112,602 12 111,569 12 110,851 12 Industrial 269 268 267 Total 922,444 100 % 912,209 100 % 902,237 100 % ##TABLE_END##TABLE_START ##TABLE_END(1) Includes both revenues from customers who purchase their energy supplies from the Company and revenues from the delivery of energy to those commercial and industrial customers that purchase their energy from ESSs. (2) Amount for the year ended December 31, 2020 is primarily comprised of $24 million of amortization, including interest, related to the deferral recorded in 2018 for the net tax benefits due to the change in corporate tax rate under the United States Tax Cuts and Jobs Act of 2017 (TCJA). (3) Includes both energy sold to retail customers and energy deliveries to those commercial and industrial customers that purchase their energy from ESSs. The following table presents additional annual

averages for retail customers. Certain supplemental tariff collections are excluded from revenues as they are not considered a part of the Companys base retail prices for these calculations. ##TABLE_START Years Ended December 31, 2022 2021 2020 Residential Revenue per customer (in dollars): $ 1,362 $ 1,320 $ 1,226 Usage per customer (in kilowatt hours): 9,991 9,968 9,804 Revenue per kilowatt hour (in cents): 13.63 13.24 12.50 Commercial Revenue per customer (in dollars): $ 6,491 $ 6,303 $ 5,684 Usage per customer (in kilowatt hours): 63,923 64,478 61,837 Revenue per kilowatt hour (in cents): 10.15 9.78 9.19 Industrial Revenue per customer (in dollars): $ 1,156,371 $ 1,044,314 $ 921,540 Usage per customer (in kilowatt hours): 22,097,472 20,002,246 18,472,161 Revenue per kilowatt hour (in cents): 5.23 5.22 4.99 ##TABLE_ENDFor additional information, see the Results of Operations section in Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. In addition to standard cost-of-service pricing, the Company offers different pricing options including a daily market price option, various time-of-use options, and several renewable energy options. For additional information on customer options, see Customer Choice Programs within this Customers and Revenues section of this Item 1. Residential customers include single family housing, multiple family housing (such as apartments, duplexes, and town homes), mobile homes, and small farms. Residential demand is sensitive to the effects of weather. The Company had seen its highest peak demand during the winter heating season although increased use of air conditioning in PGEs service territory has caused the summer peaks to increase over time. In recent years, including 2022, summer peaks have exceeded winter peaks and long-term load forecasts expect that trend to continue. An extreme winter temperature event on December 22, 2022, caused a new winter peak for the first time since 1998. Economic conditions can also affect residential demand as job growth and population growth in PGEs service territory have led to increased customer growth rates. The COVID-19 pandemic has introduced additional behavioral patterns as residential customers spend more time at home. Residential demand is also impacted by energy efficiency measures and increased rooftop solar penetration in the service territory; however, the Companys decoupling mechanism was intended to mitigate the financial effects of such measures. For further information regarding the decoupling mechanism, see Decoupling among the Regulatory Matters in the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Commercial customers consist of non-residential customers who accept energy deliveries at voltages equivalent to those delivered to residential customers. This customer class includes most businesses, small industrial companies, and public street and highway lighting accounts. The Companys commercial customer demand is somewhat less susceptible to weather conditions than residential customer demand. Economic conditions and fluctuations in total employment in the region can lead to changes in energy demand from commercial customers. Energy efficiency measures also impact commercial demand, as measures have focused in the commercial sector in recent years, although the Companys decoupling mechanism was intended to partially mitigate the financial

effects of such measures. For further information regarding the decoupling mechanism, see Decoupling among the Regulatory Matters in the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Industrial customers consist of non-residential customers who accept delivery at higher voltages than commercial customers, with pricing based on the amount of electricity delivered under the applicable tariff. Demand from industrial customers is primarily driven by economic conditions, with weather having little impact on this customer class. Customer Choice Programs Under cost-of-service pricing, residential and small commercial customers may select portfolio options from PGE that include time-of-use and renewable resource pricing. Pricing options other than cost-of-service are available to certain commercial and industrial customers for a one-year period, including daily market index-based pricing under which the Company provides the electricity, and Direct Access, whereby customers purchase electricity directly from an ESS. PGE receives revenue from Direct Access customers only for the transmission and delivery of the volume of electricity delivered, along with fixed transition adjustments intended to mitigate the shifting of excess charges to the Companys cost-of-service customers. Certain large commercial and industrial customers may elect a fixed three-year or a minimum five-year term, to be served either by an ESS, or by the Company under the daily market index-based price option. Participation in the fixed three-year and minimum five-year opt-out programs for existing and planned load is capped at 300 average megawatts (MWa) in aggregate. In 2020, the OPUC issued an order that required PGE to begin offering, to eligible customers, enrollment in the New Large Load Direct Access program, which is capped at 119 MWa in total, for unplanned, large, new loads and large load growth at existing sites. For further information regarding Direct Access deliveries, see Customers and demand in the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. PGEs customers have a desire for purchasing clean energy, as over 234 thousand residential and small commercial customers voluntarily participate in PGEs Green Future Program, the largest renewable power program by participation in the nation. Oregons most populous city, Portland, and most populous county, Multnomah, have each passed resolutions to achieve 100 percent clean and renewable electricity by 2035 and 100 percent economy-wide clean and renewable energy by 2050. Other jurisdictions in PGEs service area have set, or are considering, similar goals. The Company implemented a new customer service option, the Green Future Impact Program, which allows for 100 MW of PGE-provided power purchase agreements for renewable resources and up to 200 MW of customer-provided renewable resources. Approved by the OPUC in 2019, the program provides business customers access to bundled renewable attributes from those resources. In March 2021, the OPUC issued an order that expanded the program by 200 MW and provided for the possibility of PGE ownership of the underlying renewable resources under certain conditions. Through this voluntary program, the Company seeks to align sustainability goals, cost and risk management, and reliable integrated power while

providing customer choice and a cleaner energy system. In December 2021, the OPUC issued an order, which approved a petition to increase capacity under the customer-provided renewable resources by 250 MW, which brings the total available capacity under the program to 750 MW. For more information on the Companys power purchase agreements that currently serve the Green Future Impact Program, see Green Future Impact Program within Purchased Power in the Power Supply section of this Item 1. Wholesale Revenues PGE participates in the wholesale electricity marketplace in order to balance its supply of power to meet the needs of its retail customers. Interconnected transmission systems in the western United States serve utilities with diverse load requirements and allow the Company to purchase and sell electricity, largely through bi-lateral agreements, within the region to serve retail demand. PGEs engagement in the wholesale electricity marketplace depends upon numerous factors, including the relative price and availability of power, hydro and wind conditions, and daily and seasonal retail demand. The Company also participates in the California Independent System Operators western Energy Imbalance Market (western EIM), which allows for load balancing with other western EIM participants in five-minute intervals. Wholesale revenues represented 14% of total revenues in 2022, 11% in 2021, and 8% in 2020. Other Operating Revenues Other operating revenues consist primarily of gains and losses on the sale of natural gas volumes purchased that exceeded what was needed to fuel the Companys generating facilities, as well as revenues from transmission services, excess transmission capacity resales, pole attachment rentals, and other electric services provided to customers. Other operating revenues represented 2% of total revenues in 2022, 3% in 2021, and 2% in 2020. Seasonality Demand for electricity by PGEs residential and, to a lesser extent, commercial customers is affected by seasonal weather conditions. The Company uses heating and cooling degree-days to determine the effect of weather on the demand for electricity. Heating and cooling degree-days, determined by taking the difference between the average daily temperature and a baseline of 65 degrees, provide cumulative variances over a period of time, to indicate the extent to which customers are likely to have used electricity for heating or cooling. The higher the number of degree-days, the greater the expected demand for electricity. The following table presents the heating and cooling degree-days for the most recent three-year period, along with current 15-year averages for the most recent year provided by the National Weather Service, as measured at Portland International Airport: ##TABLE_START Heating Degree-Days Cooling Degree-Days 2022 4,103 865 2021 3,828 838 2020 3,836 600 15-year average 4,103 569 ##TABLE_ENDIn June 2021, PGE set a new all-time high net system load peak of 4,453 megawatts (MW), surpassing the previous all-time peak that occurred in December 1998 by more than 9%. While the Companys previous summer peak of 3,976 MW had occurred in August 2017, that level has been exceeded now in each of the past two summers. In December 2022, a new winter peak of 4,113 MW occurred. The following table presents PGEs average winter (defined as January, February, and December) and summer (defined as June through September) loads for the periods

presented, along with the corresponding peak load (in MWs) and month in which such peak occurred. As illustrated, although the average winter loads continue to exceed average summer loads, the Company has seen its highest annual peak loads during the summer months in recent years: ##TABLE_START Winter Loads Summer Loads Average Peak Month Average Peak Month 2022 2,773 4,113 December 2,529 4,255 July 2021 2,659 3,629 December 2,492 4,453 June 2020 2,566 3,367 December 2,289 3,771 July ##TABLE_ENDThe Company tracks and evaluates both load growth and peak load requirements for purposes of long-term load forecasting, integrated resource planning, and preparing general rate case assumptions. Behavior patterns, conservation, energy efficiency initiatives and measures, weather effects, economic conditions, distributed generation including rooftop solar, transportation and building electrification, and demographic changes all play a role in determining expected future customer demand and the resulting resources the Company may need to adequately meet those loads and maintain adequate capacity reserves. Power Supply PGE utilizes its generating resources, as well as wholesale power purchases from third parties to meet the needs of its retail customers. The volume of electricity the Company generates is dependent upon, among other factors, the capacity and availability of its generating resources and the price and availability of wholesale power and natural gas. As part of its power supply operations, the Company enters into short- and long-term power and fuel purchase and sale agreements. PGE executes economic dispatch decisions concerning its own generation and participates in the wholesale market in an effort to obtain reasonably-priced power for its retail customers, manage risk, and administer its long-term wholesale contracts. The Company also performs portfolio management and wholesale market sales services for third parties in the region. The Company also encourages energy efficiency measures to help meet its energy requirements and promotes the use of various demand side management products to reduce load during peak time usage. PGEs resource and contracted capacity (in MW) was as follows: ##TABLE_START As of December 31, 2022 2021 Capacity % Capacity % Generation: Thermal (1) : Natural gas 1,842 32 % 1,842 35 % Coal 296 4 296 5 Total thermal 2,138 37 2,138 40 Wind (2) 817 15 817 16 Hydro (3) 419 7 495 9 Total generation 3,374 59 3,450 65 Purchased power: Long-term contracts: Hydro (3) 871 15 803 15 PURPA qualifying facilities (4) 315 5 298 6 Dispatchable standby generation 130 2 130 2 Capacity 100 2 100 2 Wind (2) 300 5 300 6 Solar (5) 57 1 7 Biomass 10 10 Total long-term contracts 1,783 31 1,648 31 Short-term contracts 597 10 216 4 Total purchased power capacity 2,380 41 1,864 35 Total resource capacity 5,754 100 % 5,314 100 % ##TABLE_END##TABLE_START ##TABLE_END(1) Capacity represents the MW the plants are capable of generating under normal operating conditions, which is affected by ambient temperatures, net of electricity used in the operation of the plant. (2) Capacity represents nameplate and differs from expected energy to be generated, which is expected to have a capacity factor range from 30 to 40%, dependent upon wind conditions. (3) Capacity represents net capacity and differs from expected energy to be generated, which is expected to have a capacity factor range from 40 to 50%,

dependent upon river flows. (4) Capacity represents contracted capacity for power purchase agreements (PPAs) under the Public Utility Regulatory Policies Act of 1978 (PURPA). (5) Capacity includes 50 MW from the solar component of Wheatridge. The Wheatridge facility also includes 30 MW related to the battery component which is not reflected in the table above. For information regarding actual generating output and purchases for the years ended December 31, 2022 and 2021, see the Results of Operations section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Generation PGEs generating resources consist of six thermal plants (natural gas- and coal-fired), three wind farms, and seven hydroelectric facilities. The portion of PGEs retail load requirements generated by its plants varies from year to year and is determined by various factors, including planned and unplanned outages, availability and price of coal and natural gas, precipitation and snow-pack levels, the market price of electricity, and wind variability. For a complete listing of these facilities, see Generating Facilities in Item 2.Properties. Thermal The Company has five natural gas-fired generating facilities: PW1, PW2, Beaver, Coyote Springs Unit 1 (Coyote Springs), and Carty Generating Station (Carty). The Company operated, and continues to have a 90% ownership interest in the Boardman coal-fired generating plant (Boardman), which ceased coal-fired operations during the fourth quarter of 2020. The Company has begun decommissioning the facility. The Company also has a 20% ownership interest in the Colstrip Units 3 and 4 coal-fired generating plant (Colstrip), which is located in Colstrip, Montana and operated by a third party. For additional information on Colstrip as it relates to environmental laws and regulations in the State, see RPS standards and other laws in the Overview section in Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations and Note 19, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data. Wind PGE owns and operates two wind farms, Biglow Canyon Wind Farm (Biglow Canyon) and Tucannon River Wind Farm (Tucannon River). Biglow Canyon, located in Sherman County, Oregon, consists of 217 turbines with a total nameplate capacity of 450 MW. Tucannon River, located in southeastern Washington, consists of 116 turbines with a total nameplate capacity of 267 MW. During 2020, the wind component of the Wheatridge Renewable Energy Facility (Wheatridge), located in Morrow County, Oregon, was placed into service. Although PGE does not operate Wheatridge, it owns 40 turbines with a total nameplate capacity of 100 MW and purchases the output of the remaining turbines, with a nameplate capacity of 200 MW through power purchase agreement. PGE and NextEra Energy Resources, LLC, a subsidiary of NextEra Energy, Inc. have entered into agreements to construct a 311 MW wind energy facility, which will be part of the larger Clearwater Wind development in Eastern Montana. This additional wind capacity is not reflected in the table above. For more information regarding the Clearwater Wind development, see The Resource Planning Process within the Overview section of Item 7 Managements Discussion and Analysis of Financial Condition and Results of Operations. Hydro The Companys FERC-licensed

hydroelectric projects consist of Pelton/Round Butte on the Deschutes River near Madras, Oregon (discussed below), four plants on the Clackamas River, and one on the Willamette River. As of December 31, 2021, PGE had a 66.67% ownership interest in the 455 MW Pelton/Round Butte hydroelectric project on the Deschutes River, with the remaining interest held by the Confederated Tribes of the Warm Springs Reservation of Oregon (CTWS). A 50-year joint license for the project, which is operated by PGE, was issued by the FERC in 2005. The CTWS had an option to purchase an additional undivided 16.66% ownership interest in Pelton/Round Butte in 2021, and closed on the purchase of this incremental undivided ownership interest on January 1, 2022. As a result, PGEs ownership interest in the project is 50.01%. CTWS has a second option in 2036 to purchase an undivided 0.02% interest in Pelton/Round Butte. If the second option is exercised, CTWSs ownership percentage would exceed 50%. PGE purchases 100% of the CTWSs share of the project output. For more information see CTWS within Purchased Power in the Power Supply section of this Item 1. Fuel Supply PGE contracts for natural gas and coal supplies required to fuel the Companys thermal generating plants, with certain plants also able to operate on fuel oil, if needed. In addition, the Company uses forward, future, swap, and option contracts to manage its exposure to volatility in natural gas prices. Natural Gas Physical supplies of natural gas are generally purchased up to twelve months in advance of delivery and based on anticipated operation of the plants. PGE manages the price risk of natural gas supply through the use of financial contracts up to 60 months in advance of expected need of energy. PGE owns 79.5%, and is the operator of record, of the KB Pipeline, which directly connects PW1, PW2, and Beaver to the Northwest Pipeline, an interstate natural gas pipeline operating between British Columbia and New Mexico. Currently, PGE transports natural gas on the KB Pipeline for its own use under a firm transportation service agreement, with capacity offered to others on an interruptible basis to the extent not utilized by the Company. PGE has access to 111,805 Dth per day of firm natural gas transportation capacity on the Northwest Pipeline to serve the three plants. PGE has access to 4.1 billion cubic feet of natural gas storage in Mist, Oregon from which it can draw when economic factors favor its use or in the event that natural gas supplies are interrupted. The storage facility, owned and operated by NW Natural, may be utilized to provide fuel to PW1, PW2, and Beaver. To serve Coyote Springs and Carty, PGE has access to 120,000 Dth per day of firm natural gas transportation capacity on three pipeline systems accessing gas fields in Alberta, Canada. Coal The Colstrip co-owners obtain coal to fuel the plant via conveyor belt from a mine that lies adjacent to the facility and is the sole source of coal supply for the plant. The coal supply contract with the owner of the mine is scheduled to expire at the end of 2025. The terms of the contract and the quality of coal are expected to allow the facility to operate within required emissions limits. Purchased Power PGE supplements its own generation with power purchased in the wholesale market to meet its retail load requirements. The Company utilizes short- and long-term wholesale power purchase contracts in an effort to provide the most favorable economic mix on a variable cost

basis. PGEs medium-term power cost strategy helps mitigate the effect of price volatility on its customers due to changing energy market conditions. The strategy allows the Company to take positions in power and fuel markets up to five years in advance of physical delivery. By purchasing a portion of anticipated energy needs for future years over an extended period, PGE mitigates a portion of the potential future volatility in the average cost of purchased power and fuel. The Companys major power purchase contracts consist of the following (also see the preceding table which summarizes the average resource capabilities related to these contracts): Hydro During 2022, the Company had the following agreements: Public Utility Districts PGE has long-term power purchase contracts with certain public utility districts (PUDs) in the state of Washington for a portion of the output of two hydroelectric projects on the mid-Columbia River. Although the projects currently provide PGE a total of 410 MW of capacity through contracts as shown below, actual energy received is dependent upon river flows and capacity amounts may decline over time: 162 MW of capacity with Grant County PUD that expires in 2052; 148 MW of capacity with Douglas County PUD that expires in 2028; and 100 MW of capacity with Douglas County PUD that expires in 2025. CTWS PGE has a long-term agreement under which the Company purchases output from CTWS interest in the Pelton/Round Butte hydroelectric project. Although the agreement provides approximately 224 MW of net capacity, actual energy received is dependent upon river flows. The term of the agreement coincides with the term of the FERC license for this project, which expires in 2055. Under a separate PPA executed in 2014, PGE pays fixed capacity and energy charges to CTWS for 100% of its share of the project through 2024. On June 30, 2021 the CTWS notified PGE of their intent to exercise their option to purchase an additional undivided 16.66% ownership interest in Pelton/Round Butte and closed on the purchase on January 1, 2022. As a result of the sale, capacity from company-owned generation decreased by approximately 76 MW, and capacity from purchased power increased by a corresponding amount. Under the PPA, PGE purchases 100% of the CTWSs additional share of the project and payments under the PPA increase proportionately. In the fourth quarter of 2021, PGE and CTWS executed an additional 16-year PPA which begins on January 1, 2025, that effectively extends the term from 2024 to 2040 and increases the capacity payments in the extension period. Other The remaining capacity is primarily comprised of two additional contracts that provide for the purchase of power generated from hydroelectric projects with capacity of 236 MW in total: 200 MW of capacity with Bonneville Power Administration that expires in 2024; and 36 MW of capacity with Portland Hydro that expires in 2032 PURPA qualifying facilities PGE is required to purchase power from PURPA qualifying facilities (QFs), as mandated by federal law. QFs are generating facilities that fall within the following two categories: i) qualifying generation facilities with a capacity of 80 MW or less and whose primary energy source is renewable (hydro, wind, solar, biomass, waste, or geothermal); or ii) qualifying cogeneration facilities that sequentially produce electricity and another form of useful thermal energy (e.g., heat, steam) in a way that is more efficient than the separate production of each form of

energy. As of December 31, 2022, PGE had contracts with 67 online QFs, providing a total of 315 MW of capacity. As of December 31, 2022, PGE has six contracts with QFs representing 127 MW of capacity that are not yet operational, of which two of the QF PPAs are in default because the QF has failed to complete construction and become operational by the date required by the PPA. The PPAs provide that the QF has one year to cure its default. If the QF has failed to cure, PGE is permitted to immediately terminate the QF PPA upon expiration of the cure period. The term of a QF PPA generally ranges from 15 to 23 years. The expense and volume of purchases from QFs for the years ended December 31, 2022 and 2021 were as follows: ##TABLE_START 2022 2021 PURPA contract expense (in millions) $ 62 $ 55 MWh purchased under PURPA contracts (in thousands) 750 683 Average cost per MWh from PURPA contracts $ 82.90 $ 79.89 ##TABLE_ENDExpenses incurred related to PURPA contracts are included in PGEs AUT. Dispatchable Standby Generation (DSG) PGE has a DSG program under which the Company can start, operate, and monitor customer-owned backup generators when needed to provide NERC-required operating reserves. As of December 31, 2022, there were 59 customer-owned sites with a total DSG capacity of 130 MW. PGE continues to pursue expansion of the program with the goal of having an additional 3 to 10 MW of customer-owned DSG projects online by the end of 2023. Capacity PGE has one capacity contract representing up to 100 MW of seasonal capacity during the summer and winter peak periods obtained from a natural gas-fired resource, which expires in 2024. Wind PGE has three contracts representing 300 MW of capacity to purchase power generated from renewable wind resources that extend to 2028, 2035, and 2051. The expected energy from these wind resources will vary from the nameplate capacity due to varying wind conditions. PGE and NextEra Energy Resources, LLC, a subsidiary of NextEra Energy, Inc. have entered into agreements to construct a 311 MW wind energy facility, which will be part of the larger Clearwater Wind development in Eastern Montana. This additional wind capacity is not reflected in the table above. For more information regarding the Clearwater Wind development, see The Resource Planning Process within the Overview section of Item 7 Managements Discussion and Analysis of Financial Condition and Results of Operations. Solar PGE has four contracts representing 57 MW of capacity to purchase power generated from photovoltaic solar projects. Two of these projects extend to 2036 while the other two extend to 2037 and 2042. The expected energy from these solar resources will vary from the nameplate capacity due to varying solar conditions. Construction on the solar and battery components of Wheatridge was completed in 2022. The solar component of Wheatridge supplies the Company with 50 MW of capacity. The facility also includes 30 MW related to the battery component which is not reflected in the table above. Subsidiaries of NextEra Energy Resources, LLC own the solar and battery components, and sell their portion of the output to PGE. Biomass PGE has one contract to purchase biomass energy that is set to expire in June 2023. Green Future Impact Program PGE has three contracts representing 360 MW of capacity to purchase power generated from renewable resources to support the Green Future

Impact Program: a 15-year contract with Avangrid Renewables representing 162 MW from a renewable solar facility in Gilliam County, Oregon that was placed in service in January 2023. This additional capacity is not reflected in the table above; and a 15-year contract with Avangrid Renewables representing 138 MW from a renewable solar facility in Wasco County, Oregon that is expected to be placed in service in December 2023. This additional capacity is not reflected in the table above. a 15-year contract with Avangrid Renewables representing 60 MW from a renewable solar facility in Wasco County, Oregon that is expected to be placed in service in December 2023. This additional capacity is not reflected in the table above. For additional information on the Green Future Impact Program, see Customer Choice Programs within the Customers and Revenues section of this Item 1. Short-term contracts These contracts are for delivery periods of one month up to one year in length. They are entered into with various counterparties to provide additional firm energy to help meet the Companys load requirements. PGE also utilizes spot purchases of power in the open market to secure the energy required to serve its retail customers. Such purchases are made under contracts that range in duration from 15 minutes to less than one month. PGE is a market participant in the western EIM, which allows certain of the Companys generating plants to receive automated dispatch signals from the California Independent System Operator (CAISO) for load balancing with other western EIM participants in five-minute intervals. For additional information regarding PGEs power purchase contracts, see Note 16, Commitments and Guarantees and Note 17, Leases, in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data. Future Energy Resource Strategy PGEs Integrated Resource Plan (IRP) outlines the Companys plan to meet future customer demand and describes PGEs future energy supply strategy. For a detailed discussion of the IRPs, see Investing in a Clean Energy Future within the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Transmission and Distribution Transmission systems deliver energy from generating facilities to distribution systems for final delivery to customers. PGE schedules energy deliveries over its transmission system in accordance with FERC requirements and operates one BAA in its service territory. In 2022, PGE delivered approximately 27 million megawatt hours (MWh) through 1,255 circuit miles of transmission lines operating at or above 115 kilovolts (kV). PGEs transmission system is part of the Western Interconnection, the regional grid in the western United States. The Western Interconnection includes the interconnected transmission systems of 11 western states, two Canadian provinces and parts of Mexico, and is subject to the reliability rules of the WECC and the NERC. PGE relies on transmission contracts with Bonneville Power Administration (BPA) to transmit a significant amount of the Companys generation to serve its distribution system. PGEs transmission system, together with contractual rights on other transmission systems, enables the Company to integrate and access generation resources to meet its customers energy requirements. PGEs generation is managed on a coordinated basis to obtain maximum load-carrying capability and efficiency. PGE has announced its

intention to join the Western Power Pool and a binding resource adequacy program for the region known as the Western Resource Adequacy Program (WRAP). For further information, see Operating Activities within the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. The Companys wholesale transmission activities are regulated by the FERC and are offered on a non-discriminatory basis, with all potential customers provided equal access to PGEs transmission system through PGEs OATT. In accordance with its OATT, PGE offers several transmission services to wholesale customers, including: Network integration transmission service, a service that integrates generating resources to serve retail loads; Short- and long-term firm point-to-point transmission service, a service with fixed delivery and receipt points; and Non-firm point-to-point service, an as available service with fixed delivery and receipt points. For additional information regarding the Companys transmission and distribution facilities, see Transmission and Distribution in Item 2.Properties. Environmental Matters PGEs operations are subject to a wide range of environmental protection laws and regulations, which pertain to air and water quality, endangered species and wildlife protection, and hazardous material. Various state and federal agencies also regulate environmental matters that relate to the siting, construction, and operation of generation, transmission, and substation facilities and the handling, accumulation, clean-up, and disposal of toxic and hazardous substances. In addition, certain of the Companys hydroelectric projects and transmission facilities are located on property under the jurisdiction of federal and state agencies, and/or tribal entities that have authority in environmental protection matters. The following discussion provides further information on certain environmental regulations that affect the Companys operations and facilities. Air Quality Clean Air Act PGEs operations, primarily its thermal generating plants, are subject to regulation under the federal Clean Air Act (CAA), which addresses particulate matter, hazardous air pollutants, and GHG emissions, among other things. Oregon and Montana, the states in which PGEs thermal facilities are located, also implement and administer certain portions of the CAA and have set standards that are at least as stringent as federal standards. PGE manages its air emissions at its thermal generating plants by the use of low sulfur fuel, emissions and combustion controls and monitoring, and sulfur dioxide allowances awarded under the CAA. Climate Change In 2015, the United States Environmental Protection Agency (EPA) released the Clean Power Plan (CPP), under which each state would have to reduce overall carbon dioxide emissions from its power sector on a state-wide basis. In 2016, the United States Supreme Court halted implementation and enforcement of the CPP. In 2018, the EPA proposed the more narrowly focused Affordable Clean Energy (ACE) rule, to repeal and replace the CPP and, in 2019, finalized the ACE rule, which established guidelines for states to develop plans to address GHG emissions from individual, existing coal-fired plants, such as Colstrip in the case of PGE. With the finalization of the ACE rule, the CPP was repealed. However, on January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE rule and remanded it, in full, back to the EPA. Notwithstanding

objections that the EPA intended to issue a new rule that took recent changes in the electricity sector into account, on October 29, 2021, the U.S. Supreme Court agreed to hear an appeal of the D.C. Circuit decision. The Supreme Court, in a February 28, 2022 decision, determined that the broad approach in the CPP regulating emissions exceeded the powers granted to EPA by Congress. The Court did not expressly determine whether EPA can regulate power sector GHG emissions through its other regulatory authority and the EPA has indicated it intends to issue a proposed successor rule to the CPP in March 2023. PGE will continue to assess the Supreme Courts decision, as well as any further EPA response, for impacts on Colstrip and the Companys existing natural gas fleet. House Bill (HB) 2021 In June 2021, the Oregon Legislature passed HB 2021, which requires retail electricity providers to reduce GHG emissions associated with serving Oregon retail electricity consumers 80% by 2030, 90% by 2035, and 100% by 2040, compared to their baseline emissions levels. The baseline levels for PGE are the average annual emissions for the years 2010, 2011, and 2012 associated with the electricity sold to its retail electricity consumers as reported to the Oregon Department of Environmental Quality (ODEQ). See HB 2021 in the Laws and Regulations section of the Overview for additional information. Any laws that would impose taxes or mandatory reductions in GHG emissions may have a material impact on PGEs operations, as the Company utilizes fossil fuels in its own power generation and other companies use such fuels to generate power that PGE purchases in the wholesale market. If incremental costs were incurred as a result of changes in the regulations regarding GHG emissions, the Company would seek recovery in customer prices. For more information regarding GHG emissions and related environmental regulation, including Oregons RPS and the Companys goals in this area, see Renewable Energy under State Regulation in the Regulation section of this Item 1. and Company Strategy in the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Water Quality The federal Clean Water Act requires that any federal license or permit to conduct an activity that may result in a discharge to waters of the United States must first receive a water quality certification or permit from the state in which the activity will occur. In Oregon, Montana, and Washington, the Department of Environmental Quality and Department of Ecology of each state are responsible for reviewing proposed projects under such requirements to ensure that federally approved activities will meet water quality standards and policies established by the respective state. PGE has obtained permits or certificates of compliance for its hydroelectric operations under the FERC licenses and continues to monitor and update equipment to meet federal and state standards. Threatened and Endangered Species and Wildlife Fish Protection The federal Endangered Species Act (ESA) has granted protection to many populations of migratory fish species in the Pacific Northwest. Long-term recovery plans for these species continue to have operational impacts on many of the regions hydroelectric projects. PGE continues to implement fish protection measures at its hydroelectric projects that were prescribed by the U.S. Fish and Wildlife Service and the National

Marine Fisheries Service under their authority granted in the ESA and the FPA. Conditions required with the operating licenses are expected to result in a minor reduction in power production and continued capital spending to modify the facilities to enhance fish passage and survival. Avian Protection Various statutes, including the Migratory Bird Treaty Act and Bald and Golden Eagle Protection Act, contain provisions for civil, criminal, and administrative penalties resulting from the unauthorized take of migratory birds and eagles. Because PGE operates facilities that can pose risks to a variety of such birds and eagles, the Company developed an Avian Protection Plan to help address and reduce risks to avian species that may be affected by Company operations. PGE has implemented such a plan for its transmission, distribution, and thermal generation facilities and additional, specific plans for its wind generation facilities. Hazardous Material PGE has a comprehensive program to comply with requirements of both federal and state regulations related to the storage, handling, and disposal of hazardous materials. The handling and disposal of hazardous materials from Company facilities is subject to regulation under the federal Resource Conservation and Recovery Act. In addition, the use, disposal, and clean-up of polychlorinated biphenyls, contained in certain electrical equipment, are regulated under the federal Toxic Substances Control Act. PGE is also subject to the Comprehensive Environmental Response Compensation and Liability Act, commonly referred to as Superfund, which provides authority to the EPA to assert joint and several liability for investigation and remediation costs for designated Superfund sites. An investigation by the EPA that began in 1997 of a segment of the Willamette River in Oregon known as Portland Harbor, revealed significant contamination of river sediments and prompted the EPA to designate Portland Harbor as a Superfund site. The EPA has listed PGE among the more than one hundred Potentially Responsible Parties (PRPs) in this matter, as PGE historically owned or operated property near the river. For additional information regarding the EPA action on Portland Harbor, see Note 19, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data. PGE is subject to regulation by the United States Department of Energy (USDOE), which, under the Nuclear Waste Policy Act of 1982, is responsible for the permanent storage and disposal of spent nuclear fuel. PGE has contracted with the USDOE for permanent disposal of spent nuclear fuel from Trojan that is stored in the Independent Spent Fuel Storage Installation (ISFSI), an NRC-licensed interim dry storage facility that houses the fuel. The NRC approved the transfer of spent nuclear fuel from a spent fuel pool to the ISFSI where it is expected to remain until permanent off-site storage is available. Shipment of the spent nuclear fuel from the ISFSI to off-site storage is not expected to be completed prior to 2059. For additional information regarding this matter, see Trojan decommissioning activities in Note 8, Asset Retirement Obligations, in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data. Human Capital Management PGEs talent and culture are vital to its ability to execute its business strategy and realize continued success. Accordingly, the Company seeks to attract and retain a talented,

motivated, and diverse workforce and maintain a culture that reflects PGEs Guiding Behaviors, drive for performance, and commitment to acting with the highest levels of honesty, integrity, compliance, and safety. Employees and Collective Bargaining Agreements PGE had 2,873 employees in its workforce as of December 31, 2022, with 673 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers (IBEW). One agreement covers 610 employees, which expires March 2025, and the other covers 63 employees, which expires August 2027. The partnership with IBEW is key to a holistic labor relations approach. In addition, PGE utilizes independent contractors and temporary personnel to supplement its workforce. Competitive Pay and Benefits PGE is committed to pay equity among its employees and offers a wide range of market-competitive benefits, including comprehensive health and welfare benefits and a 401(k) retirement plan, designed to support the physical, mental, and financial well-being of its employees. Talent Development PGE provides a variety of training and development programs for employees, as well as tuition reimbursement for job-related coursework. PGE offers a mentorship program for all regular, non-represented PGE employees to help support their growth and development. The PGE Board of Directors oversees executive talent development with the assistance of the Nominating, Governance, and Sustainability Committee and the Compensation, Culture and Talent Committee in an effort to maximize the pool of internal candidates. At least annually, the Board conducts reviews of succession plans for senior management, which includes a review of the qualifications and development plans of potential internal candidates and diversity of the succession pipeline. The Compensation, Culture and Talent Committee regularly conducts more in-depth reviews of development plans for promising management talent. PGE conducts employee engagement surveys periodically to give employees the opportunity to share their perspectives and provide feedback. Survey results are shared with PGE management so that managers can take action towards improving the employee experience. Health and Safety PGE is committed to providing a safe and healthy place of business for employees, customers, and the public. Management has established an Executive Safety Council that has oversight of the Companys efforts to create a safe workplace. In addition, PGE provides various safety resources to its employees, such as safety manuals, trainings, and incident reporting tools that are all designed to incorporate safe practices into all daily activities and promote in all employees a sense of personal commitment, responsibility, and obligation regarding safety. PGE also has an Employee Assistance Program that provides free and confidential wellness counseling to all employees and their families. Diversity, Equity, and Inclusion PGE promotes an inclusive workforce through pay equity practices, racial equity training, and development opportunities for women and people of color to advance into management. Black, Indigenous, and People of Color comprise over 26% of its employees and nearly 26% of management. One third of its employees and management, including its CEO, are female. PGE also promotes diversity and economic development through its suppliers. The Companys supplier diversity program

provides an opportunity in all competitive bid events for qualified minority-owned, women-owned, disabled veteran-owned, and emerging small business suppliers. COVID-19 Since the beginning of the COVID-19 pandemic, PGE has taken steps to protect employees. The Company continues to prioritize the health and safety of its employees and be informed by federal, state and local officials to align its efforts with current information. Information about Executive Officers The following are PGEs current executive officers: ##TABLE_START Name Age Current Position and Previous Experience Year Appointed Officer James A. Ajello 69 Senior Vice President, Finance, Chief Financial Officer, Treasurer and Corporate Compliance Officer (January 2021 to present), Senior Advisor (November 2020 to December 2020), Executive Vice President and Chief Financial Officer at Hawaiian Electric Industries (January 2009 to April 2017 - retired), Senior Vice President, Business Development at Reliant Energy (January 2000 to January 2009), Managing Director, UBS Securities (January 1984 to August 1998). 2021 Larry N. Bekkedahl 61 Senior Vice President, Advanced Energy Delivery (July 2021 to present), Vice President, Grid Architecture, Integration and Systems Operations (January 2019 to July 2021), Vice President Transmission and Distribution (August 2014 to January 2019). Senior Vice President of Transmission Services at BPA (June 2012 to August 2014), Vice President of Engineering and Technical Services at BPA (2008 to June 2012). 2014 Nicholas G. Blosser 52 Vice President Public Affairs (August 2022 to present), Chief of Staff and Deputy Cabinet Secretary and Special Assistant to the President, Office of Cabinet Affairs at The White House (March 2021 to July 2022), Intergovernmental Affairs and State Lead, Biden-Harris Transition Team (November 2020-January 2021), Chief of Staff for Oregon Governor Kate Brown (February 2017 to November 2020), Co-Founder and CEO of Celilo Group Media, Inc. (January 2000 to February 2017) 2022 M. Angelica Espinosa 45 Vice President, General Counsel (March 2022 to present), Deputy General Counsel and Corporate Secretary (June 2021 to March 2022), Chief Risk Officer and Vice President of Safety and Compliance at Southern California Gas Company (January 2019 to June 2021), Vice President, Compliance Governance and Corporate Secretary at Sempra Energy (November 2016 to January 2019) 2022 Bradley Y. Jenkins 59 Vice President, Utility Operations (January 2019 to present), Vice President, Generation and Power Operations (October 2017 to January 2019), Vice President, Power Supply Generation (September 2015 to October 2017), General Manager, Diversified Plant Operations, (November 2013 to August 2015), Plant General Manager, Boardman (September 2012 to November 2013), Operations Manager, Boardman (March 2012 to September 2012). 2015 John T. Kochavatr 49 Vice President, Information Technology and Chief Information Officer (February 2018 to present). Senior Vice President and Chief Information Officer at SUEZ Water Technologies Solutions (formerly General Electric Water and Process Technologies) (October 2017 to January 2018), Chief Information Officer and Chief Digital Officer at General Electric Water and Process Technologies (November 2012 to September 2017). 2018 ##TABLE_END##TABLE_START Anne F. Mersereau 60 Vice President, Human Resources, Diversity, Equity and Inclusion (January 2016 to present),

Employee Services Manager (January 2014 to January 2016), Change Management Consultant (January 2012 to January 2014), Human Resources Business Partner (July 2009 to December 2011). 2016 Maria M. Pope 57 President (October 2017 to present) and Chief Executive Officer (January 2018 to present), Senior Vice President, Power Supply, Operations and Resource Strategy (March 2013 to December 2017), Senior Vice President, Finance, Chief Financial Officer and Treasurer (January 2009 to February 2013). Board director (January 2006 to December 2008). Vice President and Chief Financial Officer for Mentor Graphics Corporation (July 2007 to December 2008). 2009 Brett M. Sims 54 Vice President, Strategy, Regulation and Energy Supply (October 2020 to present), Senior Director of Strategy, Commercial and Regulatory Affairs (September 2017 to October 2020), Director of Origination, Structuring Resource Strategy (May 2001 to September 2017). 2020 ##TABLE_END ITEM 1A. RISK FACTORS. When evaluating PGE and any investment in its securities, investors should consider carefully the following risk factors and all other information contained in this Annual Report on Form 10-K and in the other documents that the Company files from time to time with the SEC. The events described in the risk factors could have material effects on PGEs business, financial condition, results of operations, or cash flows, or that materially adversely affect PGEs results and cause such results to differ materially from projected results. Risk and uncertainties not currently known to the Company or that are currently deemed to be immaterial may also harm PGE. If any of these risks occur, PGEs business, financial condition, results of operations, and/or cash flows could be materially adversely affected, and the trading prices of the Companys securities could substantially decline. BUSINESS AND OPERATIONAL RISKS The effects of unseasonable or severe weather and other natural phenomena can adversely affect the Companys financial condition and results of operations, and the effects of climate change could result in more intense, frequent, and extreme weather events. Weather conditions can adversely affect PGEs revenues and costs, impacting the Companys results of operations. Variations in temperatures can affect customer demand for electricity, with warmer-than-normal winter seasons or cooler-than-normal summer seasons reducing the demand for energy. Weather conditions are the dominant cause of usage variations from normal seasonal patterns, particularly for residential customers. Rapid increases in load requirements resulting from unexpected weather changes, particularly if coupled with transmission constraints, could adversely impact PGEs cost and ability to meet the energy needs of its customers. Conversely, rapid decreases in load requirements could result in the sale of excess energy at depressed market prices. Changes in the global and local climate could result in more intense, frequent, and extreme weather events such as ice and snowstorms, high wind, flooding, changes in regional rainfall and snowpack levels, high heat events, drought conditions, and increased risk of wildfires. These events may disrupt energy delivery, cause power outages, and damage the Companys facilities and transmission and distribution system. Such events could result in a reduction in revenue and an increase in additional costs to restore service, repair facilities, purchase power and fuel to serve PGE load, and

procure insurance related to such impacts. In response to more intense, frequent, and severe weather events, PGE may need to make additional investments in generation, transmission, and distribution assets to enhance reliability and resiliency. Severe weather may also require increased PGE personnel availability, which could result in increased operating expenses as well increased safety risk. In certain instances, PGE relies on mutual aid support to assist in the recovery from severe weather. Lack of availability of mutual aid support could result in increased time to restore services to customers as well as increased costs and decreased customer satisfaction. Wildfires of greater size and prevalence, such as those of a magnitude seen in Oregon in recent years, could negatively affect public safety, the resilience of the electric grid, customers demand for power and PGEs ability and cost to procure adequate power and fuel supplies to serve its customers, PGE s ability to access the wholesale energy market, PGEs ability to operate its generating facilities and transmission and distribution systems, PGEs costs to maintain, repair, and replace such facilities and systems, and recovery of costs. PGE may be unable to effectively implement a public safety power shutoff (PSPS) and de-energize its system in the event of heightened wildfire risk, or the PSPS may not be able to prevent a wildfire, which could lead to potential liability if energized systems are determined to be the cause of wildfires that result in harm. Capital investment and operating expenses related to this risk may not be recoverable through increases in customer prices. Cybersecurity attacks, data security breaches, physical attacks and security breaches, acts of terrorism, or other similar events that could disrupt PGEs operations, require significant expenditures, or result in claims against the Company. In the normal course of business, PGE collects, processes, and retains sensitive and confidential customer and employee information, as well as proprietary business information, and operates systems that directly impact the availability of electric power and the transmission of electric power in its service territory. PGE owns and operates generation, transmission, distribution, and other facilities that depend on information technology systems. A cyber-attack may cause large-scale disruption to the U.S. bulk power system or PGE operations and could target the Companys computer systems, software, or networks to achieve such disruption. Generation, transmission, and distribution facilities, in general, have been identified as potential targets of physical or cyber-attacks. In addition, physical attacks on transmission and distribution facilities have occurred in the United States. Despite the security measures in place, the Companys systems and assets, and those of third-party service providers, could be vulnerable to cybersecurity attacks, data security breaches, physical attacks and security breaches, acts of terrorism, or other similar events that could disrupt operations, cause damage to the Companys generation, transmission, or distribution facilities, impact reliability of the transmission and distribution system, information technology systems, inhibit the capability of equipment or systems to function as designed or expected, prevent service to customers or collection of revenues, or result in the release of sensitive or confidential customer, employee, or Company information. Such events could cause a shutdown of service, expose PGE to

liability, or cause reputational damage. In addition, the Company may be required to expend significant capital and other resources to protect against security breaches or to alleviate problems caused by security breaches. A breach of certain business systems could impact PGEs ability to initiate, authorize, process, record, and report financial information. The cost of repairing damage to PGEs facilities and infrastructure caused by acts of terrorism, and the loss of revenue if such events prevent PGE from providing utility service to its customers, could adversely impact its financial condition and results of operations. PGE maintains insurance coverage against some, but not all, potential losses resulting from these risks. However, insurance is limited in scope and subject to exceptions, and may not be adequate to protect the Company against liability in all cases and insurers may dispute or be unable to perform their obligations to the Company, or may not be available at rates that are commercially reasonable. Natural or human-caused disasters and other risks could damage the Companys facilities and disrupt delivery of electricity resulting in significant property loss, repair costs, and reduced customer satisfaction. PGE has exposure to natural and human-caused disasters and other risks, including, but not limited to, a pandemic such as COVID-19, earthquake, accidents, equipment failure, acts of terrorism, acts of vandalism, computer system outages and other events. Such events, which may be amplified by the fact that PGEs business activities are concentrated in one region, could disrupt PGE operations, damage PGE facilities and systems, interrupt the delivery of electricity, increase repair and service restoration expenses, reduce revenues, cause the release of harmful materials, cause fires or flooding, and subject the Company to liability. Such events, if repeated or prolonged, can also affect customer satisfaction and the level of regulatory oversight. Electric utility operations may pose risk to public and workers safety. The operation of electric generation, transmission, and distribution infrastructure involves inherent risks, including breakdown or failure of equipment, motor vehicle accidents, fires involving the utilitys equipment, dam failure at company-owned hydroelectric facilities, public and worker safety, human contact with energized equipment, and operator error. A portion of the Companys operations relies on Company- or third party-owned natural gas transmission and distribution infrastructure and involves inherent risks, such as leaks, explosions, mechanical problems, and worker and public safety. These risks could cause significant harm to workers and the public including loss of human life, significant damage to property, adverse impacts on the environment and impairment of PGEs operations, all of which could result in financial losses that would have a material adverse effect on the Companys results of operations and financial condition. PGE is also required to comply with new and changing regulatory standards involving safety compliance. The cost to comply with such requirements could be significant, and failure to meet these regulatory standards could result in substantial fines. The inability to attract and retain a qualified workforce and to maintain satisfactory collective bargaining agreements without prolonged labor disruptions, may adversely affect PGEs results of operations. PGEs workforce includes a diverse mix of skilled professional, managerial, and technical employees, including employees represented

under collective bargaining agreements. Workforce management risks include the risk of retaining key employees, turnover due to demographic challenges as employees approach retirement age, and turnover due to macroeconomic trends such as the impacts of inflation on pensions and other retirement funding. PGE faces competition for employees within the industry and in local geographies. The Company faces the risk of labor disruption due to the outcomes of labor negotiations or the possibility that employees not currently subject to collective bargaining agreements may organize. PGE relies on a contracted workforce for specific business purposes, and may experience increased costs or inability to find contracted workforce, which may result in a negative impact on operations as well as financial impact. The construction of new facilities and the modifications or replacements of existing facilities, is subject to risks that could result in the disallowance of certain costs for recovery in customer prices or higher operating costs. Long-term increases in both the number of customers and demand for energy will require continued expansion and upgrade of PGEs generation, transmission, and distribution systems. Construction of new facilities and modifications or replacements of existing facilities could be affected by factors such as unanticipated delays and cost increases, including supply chain disruption and cost inflation, availability of skilled workforce, increases in interest rates, failure of counterparties to perform under agreements, and the failure to obtain, or delay in obtaining, necessary permits from state or federal agencies or tribal entities. Delays and cost increases could result in failure to complete the projects or the abandonment of capital projects, which could eliminate or impair PGEs ability to recover related costs in the rate determination process. In addition, failure to complete construction projects according to specifications could result in reduced plant efficiency, equipment failure, and plant performance that falls below expected levels, which could increase operating costs. REGULATORY, LEGAL, AND COMPLIANCE RISKS PGE is subject to extensive price regulation and relies on recovery of costs, the uncertainty of which affect the Companys operations and costs. PGE is subject to ongoing regulation by the FERC, the OPUC and by certain federal, state, and local authorities under environmental, permitting, and other laws. Such regulation significantly influences the Companys operating environment and affects many aspects of its business. The Company cannot predict with certainty the future course of such changes or the ultimate effect that they might have on its business, and such changes could delay or adversely affect business planning and transactions and substantially increase the Companys costs. OPUC regulates the prices that PGE charges, which is a major factor in determining the Companys operating income, financial position, liquidity, and credit ratings. As a general matter, PGE relies on customer prices to recover most of the costs incurred in connection with the operation of its business, including, among other things, costs related to capital projects (such as the construction of new facilities or the modification of existing facilities), the costs of compliance with legislative and regulatory requirements (including environmental laws), and the costs of damage from storms and other natural disasters. Regulators may deny recovery of costs it considers imprudently incurred. Although the

OPUC is required to establish customer prices that are fair, just, and reasonable, it has significant discretion in the interpretation of this standard. PGE attempts to manage its costs at levels consistent with OPUC-approved prices. However, if the Company is unable to do so, or if such cost management results in increased operational risk, the Companys financial and operating results could be adversely affected. PGE is subject to various legal and regulatory proceedings, the outcome of which is uncertain, and resolution unfavorable to PGE could adversely affect its results of operations, financial condition, or cash flows. In the normal course of its business, PGE is subject to regulatory proceedings, lawsuits, claims, and other matters, which could result in adverse judgments, settlements, fines, penalties, injunctions, or other relief. Such matters include governmental policies, legislative action, and regulatory audits, investigations, and actions, including those of the FERC and OPUC with respect to allowed rates of return, financings, electricity pricing and price structures, acquisition and disposal of facilities and other assets, construction and operation of plant facilities, transmission of electricity, recovery of power costs, operating expenses, deferrals, timely recovery of costs and capital investments, and current or prospective wholesale and retail competition. These matters are subject to many uncertainties, the ultimate outcome of which management cannot predict. The final resolution of certain matters in which PGE is involved could result in disallowance of operating expenses previously deferred or could require that the Company incur expenditures over an extended period and in a range of amounts that could have an adverse effect on its cash flows and results of operations. Similarly, the terms of resolution could require the Company to change its business practices and procedures, which could also have an adverse effect on its cash flows, financial position, or results of operations. New laws, changes in legal precedent, or novel interpretations of existing regulations could also result in adverse effects on cash flows and results of operations. There are certain pending legal and regulatory proceedings that may have an adverse effect on results of operations and cash flows for future reporting periods. For additional information, see Item 3.Legal Proceedings, Regulatory Matters within the Overview of Item 7. Managements Discussion and Analysis of Financial Condition and Results of Operations, and Note 19, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data. Compliance with environmental laws and regulations may result in capital expenditures, increased operating costs and various liabilities, and adverse impact on the Companys results of operations. PGE is subject to various environmental laws, regulations, and other standards including federal, state and local environmental statutes, rules and regulations relating to air quality, water quality and usage, soil quality, emissions of greenhouse gases (GHG) such as carbon dioxide, waste management, hazardous wastes, fish, avian and other wildlife mortality and habitat protection, historical artifact preservation, natural resources, health, and safety. Compliance with such laws and regulations could, among other things, prevent or delay the development of power generation and transmission and distribution facilities, restrict output of facilities, limit the use of fuels required for power generation,

require additional pollution control equipment, require investment in non-emitting resources, and otherwise increase costs and increase capital expenditures. A portion of PGEs total system load is supplied with power generated from hydroelectric and wind generating resources. Operation of these facilities is subject to regulation related to the protection of fish and wildlife. Changes to the listing of various plants and species of fish, birds, and other wildlife as threatened or endangered could result in increased mitigation activities, which could have a material impact on PGEs financial condition and results of operations. Salmon recovery plans could include further major operational changes to the regions hydroelectric projects, including those owned by PGE and those from which the Company purchases power under long-term contracts. In addition, laws relating to the protection of migratory birds and other wildlife could impact the development and operation of transmission and distribution lines and wind projects. Also, new interpretations of existing laws and regulations could be adopted or become applicable to such facilities, which could further increase required expenditures for salmon recovery and endangered species protection and reduce the availability of hydroelectric or wind generating resources to meet the Companys energy requirements. Compliance with any new or additional GHG emissions reduction requirements could require PGE to incur significant expenditures, including those related to carbon capture and sequestration technology, purchase of emission allowances and offsets, fuel switching, and the retirement or replacement of high-emitting generation facilities with non-emitting facilities. The cost to comply with potential GHG emissions reduction requirements is subject to significant uncertainties, including those related to: the timing of the implementation of emissions reduction rules; required levels of emissions reductions; requirements with respect to the allocation of emissions allowances; the maturation, regulation, and commercialization of carbon capture, sequestration, and storage technology; and PGEs compliance alternatives. Although the Company cannot currently estimate the effect of future laws and regulations on its results of operations, financial condition, or cash flows, the costs of compliance with such legislation or regulations could be material. Changes in tax laws may have an adverse impact on the Companys financial position, results of operations, and cash flows. PGE makes judgments and interpretations about the application of tax law when determining the provision for taxes. Such judgments include the timing and probability of recognition of income, deductions, and tax credits, which are subject to challenge by taxing authorities. Additionally, treatment of tax benefits and costs for ratemaking purposes could be different than what the Company anticipates or requests from the State regulatory commission, which could have a negative effect on the Companys financial condition and results of operations. PGE owns and operates renewable generating facilities, which generate federal production tax credits (PTCs) that PGE uses to reduce its federal tax obligations. The amount of PTCs earned depends on the level of electricity output generated and the applicable tax credit rate. A variety of operating and economic parameters, including adverse weather conditions and equipment reliability, could significantly reduce the PTCs generated by the Companys wind facilities resulting

in a material adverse impact on PGEs financial condition and results of operations. These PTCs generate tax credit carryforwards that the Company plans to utilize in the future to reduce income tax obligations. If PGE cannot generate enough taxable income in the future to utilize all of the tax credit carryforwards before the credits expire, the Company may incur material charges to earnings. ECONOMIC, FINANCIAL, AND MARKET RISKS A decrease in customer demand for electricity may negatively impact PGEs business. Unfavorable economic conditions in Oregon, such as, for example, increased inflation, may result in reduced demand for electricity and impair the financial stability of PGEs customers. Such reductions in demand could adversely affect PGEs results of operations and cash flows. Economic conditions could also result in an increased level of uncollectible customer accounts and cause the Companys vendors and service providers to experience cash flow problems and be unable to perform under existing or future contracts. Customer demand could also be negatively impacted by PGEs ability to attract and retain customers, mandated energy efficiency measures, demand side management programs, potential formation of community choice aggregation programs, distributed generation resources, and economic and demographic conditions, such as population changes, job and income growth, new construction, new business formation and the overall level of economic activity. Development, improvement, and adoption of technological advances could lead to declines in energy use per customer. Some or all of these factors could impact the demand for electricity. The decline in revenues due to decreased customer demand for electricity may increase customer prices for remaining customers, as PGEs revenue requirement is designed to cover its fixed utility operating expenses. Increased customer prices could further reduce customer demand for electricity and strain PGEs ability to attract and retain customers. The loss of customers, the inability to replace those customers with new customers, and the decrease in demand for electricity could negatively impact PGEs financial condition and results of operations. Capital and credit market conditions could adversely affect the Companys access to capital, cost of capital, and ability to execute its strategic plan. Access to capital and credit markets is important to PGEs ability to operate. The Company expects to issue debt and equity securities, as necessary, to fund its future capital requirements. Volatility of interest rates could negatively impact PGEs cost of debt and results of operations. In addition, contractual commitments and regulatory requirements may limit the Companys ability to delay or terminate certain projects. If the capital and credit market conditions in the United States and other parts of the world deteriorate, the Companys future cost of debt and equity capital, as well as access to capital markets, could be adversely affected. In addition, sales or issuances of substantial amounts of PGEs common stock in the public market, including upon settlement of the forward sale agreements entered into in 2022, could cause the market price of PGEs common stock to decline. This could impair the Companys ability to raise additional capital through the sale of equity securities. Future sales or issuances of common stock or other equity-related securities could be dilutive to holders of common stock and could adversely affect their voting and other rights and

economic interests. PGE expects to raise additional capital in the future. PGE may raise additional funds through public or private equity or debt offerings or other financings, as well as additional borrowings under existing credit facilities. Any new debt financing entered into may involve covenants that restrict operations more than PGEs current outstanding debt and credit facilities. These restrictive covenants could include limitations on additional borrowings, specific restrictions on the use of assets, and prohibitions or limitations on the Companys ability to create liens, pay dividends, receive distributions from subsidiaries, redeem or repurchase stock or make investments. These factors could hinder the Companys access to capital markets and limit or delay the ability to carry out the Companys capital expenditure plan or pursue other opportunities beyond the current capital expenditure plan. The declaration of future dividends is at the discretion of the Board of Directors and is not guaranteed and, in some circumstances, the payment of dividends may be limited by the terms of PGEs debt instruments. PGE has historically paid regular quarterly dividends on common stock. However, the declaration of dividends is at the discretion of PGEs Board of Directors and is not guaranteed. The amount of common stock dividends, if any, will depend upon results of operations and financial condition, future capital expenditures and investments, the rights of holders of any outstanding shares of preferred stock, and other factors that the Board of Directors considers relevant. In addition, the terms of the Companys debt instruments may limit the payment of dividends. Under the Indenture of Mortgage and Deed of Trust, dated July 1, 1945, as amended and supplemented to date, between PGE and Wells Fargo Bank, National Association, so long as any of the first mortgage bonds are outstanding, the Company may not pay or declare dividends (other than stock dividends) on common stock or purchase or retire for a consideration (other than in exchange for other shares of PGEs capital stock or the proceeds from the sale of other shares of capital stock) any shares of capital stock of any class, if the aggregate amount distributed or expended after December 31, 1944 would exceed the aggregate amount of PGEs net income, as adjusted, available for dividends on common stock accumulated after December 31, 1944. At December 31, 2022, $399 million of accumulated net income was available for payment of dividends under this provision. Adverse changes in PGEs credit ratings could negatively affect its access to the capital markets and its cost of borrowed funds. Credit rating agencies routinely evaluate the Company, and their ratings of long-term and short-term debt are based on a number of factors, including the perceived supportiveness of the regulatory environment affecting the utility operations, the Companys cash generating capability, level of indebtedness, overall financial strength, the status of certain capital projects, as well as factors beyond PGEs control, such as tax reform, the state of the economy and industry generally. A ratings downgrade could increase fees on PGEs syndicated unsecured revolving credit facility, commercial paper program, and letter of credit facilities, increasing the cost of funding day-to-day working capital requirements, and could also result in higher interest rates on future long-term debt. A ratings downgrade could also restrict the Companys access to the commercial paper market, a principal source of short-term financing, or

result in higher interest costs. In addition, if Moodys Investors Service (Moodys) and/or SP Global Ratings (SP) reduce their rating on PGEs unsecured debt to below investment grade, the Company could be subject to requests by certain wholesale counterparties to post additional performance assurance collateral, which could have an adverse effect on the Companys liquidity and ability to participate in the wholesale markets. Under certain circumstances, banks participating in PGEs syndicated unsecured revolving credit facility could decline to fund advances requested by the Company or could withdraw from participation in the credit facility, which could adversely affect PGEs liquidity. PGE currently has a syndicated unsecured revolving credit facility with several banks for an aggregate amount of $650 million. The revolving credit facility provides a primary source of liquidity and may be used to supplement operating cash flow and as backup for commercial paper borrowings. The revolving credit facility represents commitments by the participating banks to make loans and, in certain cases, to issue letters of credit. The Company is required to make certain representations to the banks each time it requests an advance under the credit facility. However, in the event of a material adverse change in the business, financial condition, or results of operations of PGE, the Company may not be able to make such representations, in which case the banks would not be required to lend. PGE is also subject to the risk that one or more of the participating banks may default on their obligation to make loans under the credit facility. Adverse capital market performance could result in reductions in the fair value of benefit plan assets and increase the Companys liabilities related to such plans. Sustained declines in the fair value of the plans assets could result in significant increases in funding requirements, which could adversely affect PGEs liquidity and results of operations. Performance of the capital markets affects the value of assets that are held in trust to satisfy future obligations under PGEs defined benefit pension and other postretirement plans. Sustained adverse market performance could result in lower rates of return for these assets than projected by the Company and could increase PGEs funding requirements related to the plans. Additionally, changes in interest rates affect PGEs liabilities under the plans. As interest rates decrease, the Companys liabilities increase, potentially requiring additional funding. Performance of the capital markets also affects the fair value of assets that are held in trust to satisfy future obligations under the Companys non-qualified employee benefit plans, which include deferred compensation plans. As changes in the fair value of these assets are recorded in current earnings, decreases can adversely affect the Companys operating results. In addition, such decreases can require that PGE make additional payments to satisfy its obligations under these plans. The volatility of market prices for power and natural gas could adversely affect PGEs costs and ability to manage its energy supply, which could negatively impact the Companys liquidity and results of operations. As part of its normal business operations, PGE purchases and sells power and natural gas in the open market under short- and long-term contracts, which may specify variable prices or volumes. Market prices for power and natural gas are influenced primarily by factors related to supply and demand. These factors

generally include the adequacy of generating capacity, scheduled and unscheduled outages of generating facilities, hydroelectric and wind generation levels, prices and availability of fuel sources for generation, disruptions or constraints to transmission facilities, weather conditions, economic growth, and changes in technology. Volatility in these markets can affect the availability, price, and demand for power and natural gas. Disruption in power and natural gas markets could result in a deterioration of market liquidity, increase the risk of counterparty default, affect regulatory and legislative processes in unpredictable ways, affect wholesale power prices, and impair PGEs ability to manage its energy portfolio. Changes in power and natural gas prices can also affect the fair value of derivative instruments and cash requirements to purchase power and natural gas. If power and natural gas prices decrease from those contained in the Companys existing purchased power and natural gas agreements, PGE may be required to provide increased collateral, which could adversely affect the Companys liquidity. Conversely, if power and natural gas prices rise, especially during periods when the Company requires greater-than-expected volumes that must be purchased at market or short-term prices, PGE could incur greater costs than originally estimated. PGEs contract positions are not fully hedged against commodity prices, and hedges or other risk mitigations may not protect against significant losses. The risk of volatility in power costs is partially mitigated through the AUT and the PCAM. Application of the PCAM requires that PGE absorb certain power cost increases before the Company is allowed to recover any amount from customers. Accordingly, the PCAM is expected to only partially mitigate the potentially adverse financial impacts of forced generating plant outages, reduced hydro and wind availability, interruptions in fuel supplies, and volatile wholesale energy prices. PGE has put in place risk management policies, procedures, and controls to identify, quantify, and manage risk, however, these systems, processes, tools, and controls may not prevent material losses. Risk management procedures may not always be followed as intended, may not operate as designed, or may not identify all potential risks, including, without limitation, severe weather or employee misconduct. There is no assurance that PGEs risk management procedures will be effective in preventing or mitigating losses, and could have a material adverse effect on the Companys results of operation and financial condition. Reduced river flows, unfavorable wind conditions, and forced outages at generating and battery storage facilities can increase the cost of power required to serve customers. The Company could be required to replace energy expected from these sources with higher cost power from other facilities or with wholesale market purchases, which could have an adverse effect on results of operations. PGE derives a significant portion of its power supply from its own hydroelectric facilities and long-term purchase contracts with certain public utility districts in the state of Washington. Regional rainfall and snowpack levels affect river flows and the resulting amount of energy generated by these facilities. Shortfalls in energy expected from lower cost hydroelectric generating resources would require increased energy from the Companys other generating resources and/or power purchases in the wholesale market, which could have an adverse effect on results of

operations. PGE also derives a portion of its power supply from wind generating resources, for which the output is dependent upon wind conditions. Unfavorable wind conditions could require increased reliance on power from the Companys thermal generating resources or power purchases in the wholesale market, both of which could have an adverse effect on results of operations. Forced outages at generating facilities and battery storage facilities, both PGE-owned or under purchased power agreements, could result in power costs greater than those included in customer prices, in addition to increased repair and maintenance costs. Although the application of the PCAM could help mitigate adverse financial effects from any decrease in power supply, full recovery of any increase in power costs is not assured. Inability to fully recover such costs in future prices could have a negative impact on the Companys results of operations, as well as a reduction in renewable energy credits and loss of PTCs related to wind generating resources. The capacity provided by the Companys generating resources and third-party purchased power may not be sufficient to meet its customers energy demand requirements. PGE meets its customers energy demand requirements based on capacity obtained from its generating facilities and third-party power purchase agreements. The Company continuously evaluates how much capacity it will need to meet reasonably expected demands of customers and provide reasonable reserves. PGE is also required to file Integrated Resource Plans with the OPUC that detail the Companys plan to meet the future energy and capacity needs of its customers through a least-cost, least-risk combination of energy generation and demand reduction, while also aggressively reducing GHG emissions from the power supply. If the capacity provided by the Companys generating facilities and purchased power is not adequate to meet customers energy demands, PGE may be required to purchase more power from third parties, invest in acquiring additional generating or battery storage facilities, or invest in extending the operating life of existing generating assets. Any failure to obtain adequate capacity to meet customers energy demand requirements could increase its costs and negatively impact PGEs customer satisfaction, all of which could have an adverse impact on PGEs business and results of operations. Advances in energy technology could make PGEs business less competitive. A basic premise of PGEs business as a vertically integrated utility is the ability to produce electricity at competitive prices due to economies of scale. Furthermore, a key component of PGEs growth is its ability to construct, own, and operate facilities. Many companies and organizations conduct research and development activities to seek improvements in alternative technologies and distributed generation. Advancements in and creation of new technologies could include fuel cells and micro turbines, wind turbines, photovoltaic solar cells, distributed generation, nuclear energy, hydrogen, ongoing customer energy efficiency, two-way grid enabling customer-owned generation, and advances in batteries or energy storage. It is possible that advances in such technologies, or other current technologies, will reduce the cost of alternative methods of electricity production or storage to a level that is equal to or below that of existing methods. The electricity industry is undergoing significant change, including increased deployment of distributed

energy resources, technological advancements as described above, and political and regulatory developments. Electric utilities are experiencing increasing deployment of distributed energy resources, such as solar generation, energy storage, energy efficiency and demand response technologies. The deployment of these technologies supports PGEs decarbonization goals. The growth of new technologies will require modernization of the electric distribution grid to, among other things, accommodate increasing two-way flows of electricity and increase the grids capacity to interconnect these resources. A higher penetration of distributed energy resources may result in decreased customer demand, or may have impacts on grid reliability. Increased distributed energy resources and renewable energy resources will require new and sustained investments in grid modernization and transmission. If all such costs are not recoverable in rates, PGE could experience material increases in its commodity costs, which could impact PGEs results of operations, financial condition, or cash flows. It is also possible that alternative generation or storage resources are mandated, subsidized, or encouraged through legislation or regulation or otherwise are economically competitive and added to the available generation supply. Competitors may not be subject to the same operating, regulatory and financial requirements that the Company is, potentially causing a substantial competitive disadvantage for PGE. Changes in public policy, such as new tax incentives that PGE cannot take advantage of or efforts to deregulate the utility industry, could provide an advantage to competitors. Such alternative resources and regulatory or legislative actions could displace higher marginal cost generating units or make PGE less competitive in constructing, owning, and operating such facilities. Such a development could limit the Companys future growth opportunities and limit growth in demand for PGEs electric service. Changes in market conditions and environmental laws and regulations could negatively impact PGEs non-utility real estate investments. PGE owns, through a wholly owned subsidiary, its corporate headquarters building located in Portland, Oregon. A significant change in real estate values could adversely affect PGEs results of operations. PGE also owns unregulated properties that are currently or previously leased to third parties and located adjacent to PGEs T.W. Sullivan hydro generating facility. PGE has recorded a non-utility asset retirement obligation (ARO) for this site related to assets that are no longer in service. Significant changes in estimates for this non-utility ARO due to changes in environmental laws or regulations could adversely affect PGEs results of operations. Rapidly changing stakeholder expectations and standards with respect to PGEs environmental, social, and governance (ESG) programs could result in increased costs and exposure to incremental risk. Investors, lenders, rating agencies, customers, regulators, employees, and other stakeholders are increasing their focus on evaluating companies as corporate citizens based on their ESG programs and metrics. Based on PGEs ESG profile, investors and lenders may elect to increase their required returns on capital offered to the Company, reallocate capital, or not commit capital as a result of their assessment of the Companys ESG profile. Such actions by investors and lenders could increase PGEs cost of, or access to, capital and financing. PGE is

committed to the success of its ESG programs; however, if the Company fails to adapt or execute on its ESG strategies, or is perceived to have failed in addressing stakeholder ESG expectations or standards, which continue to evolve, PGE may suffer reputational damage, which could have a material adverse effect on its business, results of operations, and financial condition. Additionally, the cost of implementing and complying with such ESG programs could be material. Actions of activist shareholders could have a negative impact on PGEs business. Actions of activist shareholders, which can take many forms and arise in a variety of situations, could include engaging in proxy solicitations, advancing shareholder proposals, or otherwise attempting to effect changes and assert influence on the Companys board of directors and management. Dealing with such actions could result in substantial costs and divert managements and the Companys boards attention and resources from PGEs business and execution of its strategy. Such shareholder activism could give rise to perceived uncertainties regarding PGEs future, adversely affecting PGEs business opportunities, ability to access capital markets, relationships with its customers and employees, and make it more difficult to attract and retain a qualified workforce. Any such actions could have a material adverse effect on the Companys financial condition and results of operations and could cause significant fluctuations in the trading prices of its common stock based on market perceptions or other factors. PGEs business activities are concentrated in one region and future performance may be affected by events and factors unique to Oregon or the region. The Companys industry and geographic concentrations may increase exposure to risks arising from regional regulation or legislation, such as legislative action related to carbon emissions. These concentrations may also increase exposure to credit and operational risks due to counterparties, suppliers, and customers being similarly affected by changing conditions.

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Item 1. Business. ##TABLE_ENDOverview Middlesex Water Company (Middlesex) was incorporated as a water utility company in 1897 and owns and operates regulated water utility and wastewater systems primarily in New Jersey and Delaware. Middlesex also operates water and wastewater systems under contract on behalf of municipal and private clients primarily in New Jersey and Delaware.The terms the Company, we, our, and us refer to Middlesex Water Company and its subsidiaries, including Tidewater Utilities, Inc. (Tidewater) and Tidewaters wholly-owned subsidiaries, Southern Shores Water Company, LLC (Southern Shores) and White Marsh Environmental Systems, Inc. (White Marsh). The Companys other subsidiaries are Pinelands Water Company (Pinelands Water) and Pinelands Wastewater Company (Pinelands Wastewater) (collectively, Pinelands), Utility Service Affiliates, Inc. (USA) and Utility Service Affiliates (Perth Amboy) Inc., (USA-PA).The Companys principal executive offices are located at 485C Route 1 South, Suite 400, Iselin, New Jersey 08830. Our telephone number is (732) 634-1500. Our website address is http://www.middlesexwater.com. Information contained on our website is not part of this Annual Report on Form 10-K. We make available, free of charge through our website, reports and amendments filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, after such material is electronically filed with or furnished to the United States Securities and Exchange Commission (the SEC).Middlesex System Located in New Jersey, the Middlesex System provides water services to approximately 61,000 retail customers, primarily in eastern Middlesex County and under wholesale contracts to the City of Rahway, Townships of Edison and Marlboro, the Borough of Highland Park and the Old Bridge Municipal Utilities Authority. The Middlesex System treats, stores and distributes water for residential, commercial, industrial and fire protection purposes. The Middlesex System also provides water treatment and pumping services to the Township of East Brunswick under contract. The amount of water supply allocated to the Township of East Brunswick is granted directly to the Township by the New Jersey Water Supply Authority. The Middlesex System produced approximately 65% of our 2022 consolidated operating revenues.The Middlesex Systems retail customers are located in an area of approximately 55 square miles in Woodbridge Township, the City of South Amboy, the Boroughs of Metuchen and Carteret, portions of the Township of Edison and the Borough of South Plainfield, all in Middlesex County, and a portion of the Township of Clark in Union County. Retail customers include a mix of residential customers, large industrial concerns and commercial and light industrial facilities. These customers are located in generally well-developed areas of central New Jersey.The contract customers of the Middlesex System comprise an area of approximately 110 square miles with a population of over 200,000. Contract sales to the Townships of Edison and Marlboro, the City of Rahway and the Old Bridge Municipal Utilities Authority are supplemental to the water systems owned and operated by these customers. Middlesex is the sole source of water for the Borough of Highland Park and the Township of East Brunswick.Middlesex provides water service to approximately 300 customers in Cumberland County, New Jersey. This system is referred to as the Bayview System, and is not physically interconnected with the Middlesex System. The Bayview System produced less than 0.1% of our 2022 consolidated operating revenues. Tidewater System Tidewater, together with its wholly-owned subsidiary, Southern Shores, provides water services to approximately 56,000 retail customers for residential, commercial and fire protection purposes in over 460 separate communities 2in New Castle, Kent and Sussex Counties, Delaware. The Tidewater System produced approximately 26% of our 2022 consolidated operating revenues.USA-PA USA-PA operates the City of Perth Amboy, New Jerseys (Perth Amboy) water and wastewater systems under a 10-year agreement, which expires in December 2028. In addition to performing day-to day operations, USA-PA is also responsible for emergency responses and management of capital projects funded by Perth Amboy. USA-PA produced approximately 4% of our 2022 consolidated operating revenues.Pinelands Systems Pinelands Water provides water services to approximately 2,500 residential customers in Burlington County, New Jersey. Pinelands Water is not physically interconnected with the Middlesex System. Pinelands Water produced approximately 1% of our 2022 consolidated operating revenues.Pinelands Wastewater provides wastewater collection and treatment services to approximately 2,500 residential customers. Under contract, it also services one municipal wastewater system in Burlington County, New Jersey with approximately 200 residential customers. Pinelands Wastewater produced approximately 1% of our 2022 consolidated operating revenues.USA USA operates the Borough of Avalon, New Jerseys (Avalon) water utility, sewer utility and storm water system under a ten-year operations and maintenance contract expiring in 2032. In addition to performing day-to-day service operations, USA is responsible for emergency responses and management of capital projects funded by Avalon.USA operates the Borough of Highland Park, New Jerseys (Highland Park) water utility and sewer utility under a ten-year operations and maintenance contract expiring in 2030.USA also provides water and wastewater services to several other New Jersey municipalities under contracts that are not regulated by a public utility commission as to rates and service.Under a marketing agreement with HomeServe USA Corp. (HomeServe) expiring in 2031, USA offers residential customers in New Jersey and Delaware various water and wastewater related home maintenance programs. USA receives a service fee for the billing, cash collection and other administrative matters associated with HomeServes service contracts.USA produced approximately 2% of our 2022 consolidated operating revenues. White Marsh White Marsh operates or maintains water and/or wastewater systems that serve approximately 4,500 service connections under 30 separate contracts. White Marsh also owns two commercial properties that are leased to Tidewater for its administrative office campus and its field operations center. White Marsh produced approximately 1% of our 2022 consolidated operating revenues.3 Financial Information Consolidated operating revenues, operating income and net income are as follows: ##TABLE_START (Thousands of Dollars) Years Ended December 31, 2022 2021 2020 Operating Revenues $ 162,434 $ 143,141 $ 141,592 Operating Income $ 47,333 $ 33,211 $ 37,420 Net Income $ 42,429 $ 36,543 $ 38,425 ##TABLE_ENDOperating revenues were earned from the following sources: ##TABLE_START Years Ended December 31, 2022 2021 2020 Residential 52.3 % 54.3 % 54.2 % Commercial 14.0 11.7 10.9 Industrial 6.9 6.3 6.7 Fire Protection 7.8 8.8 8.8 Contract Sales 11.6 10.2 10.7 Contract Operations 7.4 8.6 8.6 Other 0.0 0.1 0.1 Total 100.0 % 100.0 % 100.0 % ##TABLE_END Water Supplies and Contracts Our New Jersey and Delaware water supply systems are physically separate and are not interconnected. In New Jersey, the Pinelands System and Bayview System are not interconnected with the Middlesex System or each other. We believe we have adequate sources of water supply to meet the current service requirements of our present customers in New Jersey and Delaware. Middlesex System Our Middlesex System produced approximately 14.2 billion gallons in 2022 from:##TABLE_START The Carl J. Olsen Surface Water Treatment Plant (CJO Plant)-11.7 billion gallons; ##TABLE_END##TABLE_START Twenty-seven Company-owned wells (ground water)-0.8 billion gallons, and; ##TABLE_END##TABLE_START The balance purchased from a non-affiliated water utility regulated by the New Jersey Board of Public Utilities (NJBPU) under an agreement which expires February 27, 2026. This agreement provides for minimum purchases of 3.0 million gallons per day (mgd) of treated water with provisions for additional purchases. ##TABLE_ENDIn December 2021, Middlesex temporarily ceased pumping from its Company-owned wells at the Park Avenue Wellfield Treatment Plant in South Plainfield, New Jersey and alternate sources of supply were obtained in order to comply with new State of New Jersey water quality regulations relative to poly- and perfluoroalkyl substances, collectively referred to as PFAS that became effective in 2021.4Prior to 2021, the Company began design for construction of an enhanced treatment process at the Park Avenue Wellfield Treatment Plant to meet the expected PFAS water quality standards anticipated to be enacted by the State of New Jersey, which at that time were unknown as to their timing and extent. In June 2022, a portion of the enhanced treatment process was completed, placed into service and is effectively treating the ground water in compliance with all state and federal drinking water standards.The Middlesex Systems distribution storage facilities are used to supply water to customers at times of peak demand, outages and emergencies.The principal source of surface water for the Middlesex System is the Delaware Raritan Canal, which is owned by the State of New Jersey and operated by the New Jersey Water Supply Authority (NJWSA). Middlesex is under contract with the NJWSA, which expires November 30, 2023, and provides for average purchases of 27.0 mgd of untreated water from the Delaware Raritan Canal, augmented by the Round Valley/Spruce Run Reservoir System. The untreated surface water is pumped to, and treated at, the CJO Plant.Water supply to customers of the Bayview System is derived from two wells, which produced approximately 6.4 million gallons in 2022.Tidewater System Our Tidewater System produced approximately 2.8 billion gallons in 2022, primarily from 178 wells. Tidewater expects to submit applications to Delaware regulatory authorities for the approval of additional wells as growth, customer demand and water quality warrant. Tidewater augments its water production with annual minimum purchases of 15.0 million gallons of treated water under contract from the City of Dover, Delaware. Tidewater does not have a central water treatment facility for the over 460 separate communities it serves. As the number has grown, many of Tidewaters individual systems have been interconnected, forming several regional systems that are served by multiple water treatment facilities owned by Tidewater. Pinelands Water System Water supply to our Pinelands Water System is derived from four wells which produced approximately 139.6 million gallons in 2022. The aggregate pumping capacity of the four wells is 2.2 mgd. Wastewater Facilities Pinelands Wastewater System The Pinelands Wastewater System discharges into the South Branch of the Rancocas Creek through a wastewater treatment plant that provides clarification, sedimentation, filtration and disinfection. The total capacity of the plant is 0.5 mgd, and the system treated approximately 93.7 million gallons in 2022. Human Capital Management The Company strives to attract and retain employees by offering competitive compensation and benefits along with career development and training opportunities in a safe, supportive and inclusive work environment. Our mission, our business philosophy and the manner in which we deliver value for our customers, our shareholders and our employees is inherent in what we, as an enterprise, profess to be our core values of Respect, Integrity, Growth, Honesty and Teamwork. Our employees success is a key element of the Companys success.Workforce As of December 31, 2022, the Company had 350 employees. None of our employees are subject to a collective bargaining agreement. We believe our employee relations are positive.5 Employee Compensation and Benefits We offer comprehensive competitive employee compensation and benefit programs consistent with job functions, skill levels, experience, knowledge and geographic location. These programs are periodically independently evaluated by a nationally recognized consulting firm to gauge effectiveness and are benchmarked against industry peers and the overall markets in which we operate our businesses. Compensation increases and incentive compensation are based on merit, which is communicated to employees and documented in our bi-annual performance evaluation process. Benefits include a variety of programs to enhance employee overall physical, mental and financial health and well-being, including healthcare insurance, employer funded retirement savings plans, life insurance, disability insurance, accident insurance, tuition reimbursement, flu shots, wellness newsletters and webinars, flexible hybrid office and remote work capabilities, incentive programs for achieving fitness milestones, financial counseling, elder care assistance, substance abuse support and more. Safety The Company has implemented safety programs and management practices designed to promote a culture of safety to protect its employees. This includes required trainings for employees, as well as specific qualifications and certifications for certain operational employees. All employees have been empowered to report, and immediately stop, work which, in their personal judgement, is unsafe or is not consistent with our safety policies and procedures. They can take this action without fear of reprisal.In response to the Coronavirus (COVID-19) pandemic, the Company continues to implement changes it determines are in the best interest of our employees and customers, as well as required to comply with government emergency orders and regulations. While the nature of our utility services business requires portions of our workforce to operate in the field and at treatment facilities, we employ and maintain a variety of processes to help ensure the safety of those employees and the public in light of the pandemic. For further discussion of the impact of the COVID-19 pandemic on the Company, see Item 7 - Managements Discussion and Analysis of Financial Condition and Results of Operation, Coronavirus (COVID-19) Pandemic .Employee Development and Training The Company employs various training and other educational programs and has developed company-wide and project-specific training and educational programs, including tuition assistance for full-time employees enrolled in pre-approved undergraduate or graduate courses or professional licensing courses. All employees receive training to identify and report operational and financial risks, as well as risks to Company brand and reputation, which fosters a personal culture of accountability and reinforces our commitment to a safe and sustainable workplace. All employees receive cybersecurity training and other education regarding their use of sensitive data. Our Executive Management team and our Board of Directors continually assess succession plans, leadership development progress and policies and strategies regarding recruitment, retention, career development, diversity, equity and inclusion. Formalized succession planning strategies have been developed for key leadership positions. Diversity, Equity Inclusion (DEI) The Company is committed to DEI based upon our belief that embracing DEI is consistent with our Company culture and benefits all stakeholders by maintaining a workforce with a variety of skills and perspectives as a result of their diverse backgrounds and experiences. The Company is a signatory to CEO Action for Diversity and Inclusion, a business led initiative which encourages companies to cultivate environments that support dialogue on DEI, implement and expand bias education and training and engage boards of directors in the development and evaluation of inclusion and diversity strategies. The Company also delivered various DEI trainings throughout 2022 to its entire employee base.The Company is focused on recruitment and/or development of both external and internal candidates so that all prospective and current employees are provided an opportunity to advance their careers. We are intentional in our efforts to attract candidates from historically marginalized groups and seek a diverse pool of candidates for 6apprenticeships and internship opportunities. Statements on Diversity, Equity and Inclusion and our Human Rights Policy can be found on our website. We continue to monitor the results of our DEI efforts and continually explore opportunities to further engage our employees and customers.Competition Our business in our franchised service areas is substantially free from direct competition for growth with other public utilities, municipalities and other entities. However, our ability to provide contract wholesale water supply and operations and maintenance services that are not under the jurisdiction of a state public utility commission is subject to competition from other public utilities, municipalities and other entities. Although Tidewater has been granted exclusive franchises for its existing community water systems, the ability to expand service areas can be affected by the Delaware Public Service Commission (DEPSC) awarding franchises to other regulated water utilities with whom we compete for such franchises and for projects.Regulation Our rates charged to customers for utility services, the quality of the services we provide and certain other matters are regulated by the NJBPU and DEPSC (collectively, the Public Utility Commissions).Our USA, USA-PA and White Marsh subsidiaries are not regulated public utilities as related to rates and service quality. However, they are subject to federal and state environmental regulations with respect to water quality and wastewater effluent quality to the extent such services are provided.We are subject to environmental and water quality regulation by the following regulatory agencies (collectively, the Government Environmental Regulatory Agencies):##TABLE_START United States Environmental Protection Agency (USEPA); ##TABLE_END##TABLE_START New Jersey Department of Environmental Protection (NJDEP) with respect to operations in New Jersey; and ##TABLE_END##TABLE_START Delaware Department of Natural Resources and Environmental Control, the Delaware Department of Health and Social Services-Division of Public Health (DEDPH), and the Delaware River Basin Commission with respect to operations in Delaware. ##TABLE_ENDIn addition, our issuances of equity securities are subject to the prior approval of the NJBPU and require registration with the Securities Exchange Commission (SEC). Our issuances of long-term debt securities are subject to the prior approval of the respective state Public Utility Commissions. Regulation of Rates and Services For regulated rate setting purposes, we account separately for our regulated utility operations to facilitate independent rate setting by the applicable Public Utility Commissions.In determining our regulated utility rates, the respective Public Utility Commissions consider the revenue, expenses and utility infrastructure used and useful in providing service to the public. Rate determinations by the respective Public Utility Commissions do not guarantee achievement by our regulated utility companies of specific rates of return for our regulated utility operations. Thus, we may not achieve the rates of return authorized by the Public Utility Commissions. In addition, there can be no assurance that any future rate increases will be granted or, if granted, that they will be in the amounts requested. Middlesex Rate Matters In December 2021, Middlesexs petition to the NJBPU seeking permission to increase its base water rates was concluded, based on a negotiated settlement, resulting in an expected increase in annual operating revenues of $27.7 million. The approved tariff rates were designed to recover increased operating costs, as well as a return on invested capital of $513.5 million, based on an authorized return on common equity of 9.6%. The increase was implemented in two phases with $20.7 million of the increase effective January 1, 2022 and the remaining $7.0 million effective 7January 1, 2023. As part of the negotiated settlement, the Purchased Water Adjustment Clause (PWAC), which is a rate mechanism that allows for recovery of increased purchased water costs between base rate case filings, was reset to zero.In September 2022, the NJBPU approved Middlesex's Emergency Relief Motion to permit Middlesex to reset its PWAC tariff rate to recover additional costs of $2.7 million for the purchase of treated water from a non-affiliated regulated water utility. The increase, effective October 1, 2022, is on an interim basis and subject to refund, with interest, pending final resolution expected in the second quarter of 2023.In March 2021, the NJBPU approved Middlesexs annual petition to reset its PWAC tariff rate to recover additional costs of $1.1 million for the purchase of treated water from a non-affiliated regulated water utility. The new PWAC rate became effective April 4, 2021.Tidewater Rate Matters On August 31, 2022, the DEPSC issued an Order requiring Tidewater to reduce its base rates charged to general metered and private fire customers by 6%, effective for service rendered on and after September 1, 2022. In June 2022, the Delaware Division of the Public Advocate had filed a petition with the DEPSC requesting that Tidewaters rates be reduced based on the claim that Tidewater had been earning above its authorized rate of return. The rate reduction is expected to reduce annual revenues by approximately $2.2 million. In March 2021, Tidewater was notified by the DEPSC that it had determined Tidewaters earned rate of return exceeded the rate of return authorized by the DEPSC. Consequently, Tidewater reset its Distribution System Improvement Charge (DSIC) rate to zero effective April 1, 2021 and refunded approximately $1.0 million to customers primarily in the form of an account credit for DSIC revenue previously billed between April 1, 2020 and March 31, 2021. A DSIC is a rate-mechanism that allows water utilities to recover investments in, and generate a return on, qualifying capital improvements made between base rate proceedings. Pinelands Rate Matters In September 2022, Pinelands Water and Pinelands Wastewater filed separate petitions with the NJBPU seeking permission to increase base rates by approximately $0.6 million and $0.4 million per year, respectively. These requests were necessitated by capital infrastructure investments both companies have made, or have committed to make, and increased operations and maintenance costs. We cannot predict whether the NJBPU will ultimately approve, deny, or reduce the amount of the requests. A decision by the NJBPU in both matters is expected in the first quarter of 2023.Southern Shores Rate Matters Effective January 1, 2020, the DEPSC approved the renewal of a multi-year agreement for water service to a 2,200 unit condominium community we serve in Sussex County, Delaware. Under the agreement, current rates were to remain in effect until December 31, 2024, unless there are unanticipated capital expenditures or regulatory related changes in operating expenses exceeding certain thresholds during this time period. In 2022, capital expenditures did exceed the established threshold and rates were increased by 5.39%, effective January 1, 2023. Beginning in 2025 and thereafter, inflation based rate increases cannot exceed the lesser of the regional Consumer Price Index or, 3%. Inflation based increases are in addition to the threshold rate increases. This agreement expires on December 31, 2029. Future Rate Filings Management monitors the need for rate relief for our regulated entities on an ongoing basis. When capital improvements and/or increases in operation, maintenance or other costs indicate a need for rate relief, base rate increase requests are filed with the respective Public Utility Commissions.8 Regulatory Service Matters Twin Lakes Utilities, Inc. (Twin Lakes) provides water services to approximately 115 residential customers in Shohola, Pennsylvania. Pursuant to the Pennsylvania Public Utility Code, Twin Lakes filed a petition requesting the Pennsylvania Public Utilities Commission (PAPUC) to order the acquisition of Twin Lakes by a capable public utility. The PAPUC assigned an Administrative Law Judge (ALJ) to adjudicate the matter and submit a recommended decision (Recommended Decision) to the PAPUC. As part of this legal proceeding the PAPUC also issued an Order in January 2021 appointing a large Pennsylvania based investor-owned water utility as the receiver (the Receiver Utility) of the Twin Lakes system until the petition is fully adjudicated by the PAPUC. In November 2021, the PAPUC issued an Order affirming the ALJs Recommended Decision, ordering the Receiver Utility to acquire the Twin Lakes water system and for Middlesex to submit $1.7 million into an escrow account within 30 days. Twin Lakes immediately filed a Petition For Review (PFR) with the Commonwealth Court of Pennsylvania (the Pennsylvania Court) seeking reversal and vacation of the escrow requirement on the grounds that it violates the Pennsylvania Public Utility Code as well as the United States Constitution. In addition, Twin Lakes filed an emergency petition for stay of the PAPUC Order pending the Pennsylvania Courts review of the merits arguments contained in Twin Lakes PFR. In December

2021, the Pennsylvania Court granted Twin Lakes emergency petition, pending its review. In August 2022, the Commonwealth Court issued an opinion upholding PAPUCs November 2021 Order in its entirety. In September 2022, Twin Lakes filed a Petition For Allowance of Appeal to the Supreme Court of Pennsylvania seeking reversal of the Commonwealth Courts decision to uphold the escrow requirement on the grounds that the Pennsylvania Court erred in failing to address Twin Lakes constitutional claims. The timing of the final decision by the Supreme Court of Pennsylvania and the final adjudication of this matter cannot be predicted at this time.The financial results, total assets and financial obligations of Twin Lakes are not material to Middlesex.COVID-19 Pandemic The NJBPU and the DEPSC have allowed for potential future recovery in customer rates of incremental costs related to the COVID-19 pandemic. The Company has not deferred any COVID-19 related incremental costs. Neither jurisdiction has yet to establish a timeline or definitive formal procedures for seeking cost recovery (for further discussion of the impact of COVID-19 on the Company, see Item 7 - Managements Discussion and Analysis of Financial Condition and Results of Operations, Coronavirus (COVID-19)).Water and Wastewater Quality and Environmental Regulations Government environmental regulatory agencies regulate our operations in New Jersey and Delaware with respect to water supply, treatment and distribution systems and the quality of the water. They also regulate our operations with respect to wastewater collection, treatment and disposal.Regulations relating to water quality require us to perform tests to ensure our water meets state and federal quality requirements. In addition, government environmental regulatory agencies continuously review current regulations governing the limits of certain organic compounds found in the water as byproducts of the treatment process. We participate in industry-related research to identify technologies that may reduce the level of organic, inorganic and synthetic compounds found in water. The cost to water utilities to comply with any proposed water quality standards depends in part on the limits set in the regulations and on the method selected to treat the water to the required standards. We regularly test our water to determine compliance with government environmental regulatory agencies water quality standards.In September 2021, the NJDEP issued a Notice of Non-Compliance (Notice) to Middlesex based on self-reporting by Middlesex that the level of Perfluorooctanoic Acid (PFOA) in water treated at its Park Avenue Wellfield Treatment Plant in South Plainfield, New Jersey exceeded a recently promulgated NJDEP standard effective in 2021. The NJDEP standard for PFOA was developed based on a Health-based Maximum Contaminant Level of 14 parts per trillion. Neither the NJDEP nor Middlesex characterized this exceedance as an acute health threat. 9However, Middlesex was required to notify its affected customers and complied in November 2021 as required by the regulation. The Notice further required the Company to take any action necessary to comply with the new standard by September 7, 2022. Prior to 2021, the Company began design for construction of an enhanced treatment process at the Park Avenue Wellfield Treatment Plant to meet the expected PFAS water quality standards anticipated to be enacted by the State of New Jersey, which at that time were unknown as to their timing and extent. Since completion was not expected until mid-2023, in December 2021, the Company implemented an interim solution to meet the Notice requirements. The Park Avenue Wellfield Treatment Plant was temporarily taken off-line and alternate sources of supply were obtained. Simultaneously, the Company accelerated a portion of the enhanced treatment project to allow a restart of the Park Avenue Wellfield Treatment Plant ahead of historical higher water demand periods during the summer months. In June 2022, a portion of the enhanced treatment process was completed, placed into service and is effectively treating the ground water in compliance with all state and federal drinking water standards.In addition to the enhanced groundwater treatment process for PFAS, we treat the groundwater supplies in our Middlesex System with chlorination for primary disinfection purposes and use air stripping for removal of volatile organic compounds.Surface water treatment in our Middlesex System is by conventional treatment; coagulation, sedimentation and filtration. The treatment process includes pH adjustment, ozone and chlorination for disinfection, and corrosion control for the distribution system.Treatment of groundwater in our Tidewater System is by chlorination for disinfection purposes and, in some cases, pH adjustment and filtration for nitrate and iron removal and granular activated carbon filtration for organics removal. Chloramination is used for final disinfection at Southern Shores.Treatment of groundwater in the Pinelands Water and Bayview Systems (primary disinfection only) is performed at individual well sites.Treatment of wastewater in the Pinelands Wastewater System includes the use of rotating biological contactors. The NJDEP and DEDPH monitor our activities and review the results of water quality tests that are performed for adherence to applicable regulations. Other applicable regulations include the Federal Lead and Copper Rule, the Federal Surface Water Treatment Rule and the Federal Total Coliform Rule and regulations for maximum contaminant levels established for various volatile organic compounds.The Company must comply with various environmental laws and regulations promulgated by the USEPA, NJDEP and other governmental agencies, including the Toxic Catastrophe Prevention Act, the Spill Prevention, Control, and Countermeasure Rule and the Discharge Prevention Program of the New Jersey Spill Compensation and Control Act. Seasonality Customer demand for our water during the warmer months is generally greater than other times of the year due primarily to additional consumption of water in connection with irrigation systems, swimming pools, cooling systems and other outside water use. Throughout the year, and particularly during typically warmer months, demand may vary with temperature and rainfall timing and overall levels. In the event that temperatures during the typically warmer months are cooler than normal, or if there is more rainfall than normal, the customer demand for our water may decrease and therefore, adversely affect our revenues.10 Management This table lists information concerning our executive management team:##TABLE_START Name Age Principal Position(s) Dennis W. Doll 64 President, Chief Executive Officer and Chairman of the Board of Directors A. Bruce OConnor 64 Senior Vice President, Treasurer and Chief Financial Officer G. Christian Andreasen, Jr. 63 Vice President-Enterprise Engineering

Robert K. Fullagar 56 Vice President-Operations Lorrie B. Ginegaw 47 Vice President-Human Resources Jay L. Kooper 50 Vice President-General Counsel and Secretary Georgia M. Simpson 49 Vice President-Information Technology Bernadette M. Sohler 62 Vice President-Corporate Affairs ##TABLE_END Dennis W. Doll Mr. Doll joined the Company as Executive Vice President in November 2004 and was named President and Chief Executive Officer, and a Director of Middlesex, effective January 1, 2006. In May 2010, he was elected Chairman of the Board, also serving as Chairman of the Boards of the Companys subsidiary companies. He is a Past President of the National Association of Water Companies and past Chairman of the Board of the New Jersey Utilities Association, representing the states electric, gas, water and telecommunications industries. He is a past Chairman of the Board of The Water Research Foundation where he continues to serve as Director Emeritus, and has served as a Director and member of the Executive Committee of the Board of Directors of the American Water Works Association. He presently serves as Treasurer and member of the Board of Court Appointed Special Advocates of Middlesex County, NJ serving the needs of children living in foster care.A. Bruce OConnor Mr. OConnor, a Certified Public Accountant, joined the Company in 1990 and was named Vice President and Chief Financial Officer in 1996 and Treasurer in 2014. On January 1, 2019, Mr. OConnor was appointed Senior Vice President of Middlesex and President of Tidewater and White Marsh. Mr. OConnor is also the principal financial officer and a Director of all Middlesex subsidiaries.G. Christian Andreasen, Jr. Mr. Andreasen, a licensed professional engineer, joined the Company in 1982, was named Assistant Vice President-Enterprise Engineering in January 2019 and promoted to Vice President-Enterprise Engineering in July 2019. He is President and a Director of Pinelands Water and Pinelands Wastewater. Mr. Andreasen serves as a Member and Vice Chair of the NJDEPs Water Supply Advisory Council. Robert K. Fullagar Mr. Fullagar, a licensed professional engineer, joined the Company in 1997, was named Assistant Vice President-Operations in January 2019 and promoted to Vice President-Operations in July 2019. He is President and a Director of USA-PA, USA and Twin Lakes. Mr. Fullagar serves as Sector Chair of the New Jersey Infrastructure Advisory Committee. Lorrie B. Ginegaw Ms. Ginegaw joined Tidewater in 2004 and in 2007 was promoted to Director of Human Resources for Middlesex. In March 2012, Ms. Ginegaw was named Vice President-Human Resources. Prior to joining the Company, Ms. Ginegaw worked in various human resources positions in the healthcare and transportation/logistics industries. Ms. Ginegaw serves as a volunteer director on the Board of the New Jersey Utilities Association.Jay L. Kooper Mr. Kooper joined the Company in 2014 as Vice President and General Counsel and serves as Secretary for the Company and all subsidiaries. Prior to joining the Company, Mr. Kooper held various positions in private and public entities as well as in private law practice, representing electric, gas, water, wastewater, telephone and cable companies as well as municipalities and private clients before 17 state public utility commissions and legislatures, federal agencies and federal and state appellate courts. Mr. Kooper serves as a volunteer director on selected non-profit utility industry-related Boards including the National Association of Water Companies (current Director and Chairman of the New Jersey Chapter) and the New Jersey State Bar Associations Public Utility Law Section (current Consultor and Past Chairman) and on other non-profit boards based in New 11Jersey, including as President of Temple BNai Abraham in Livingston, New Jersey and as a Director of the Crohns and Colitis Foundations New Jersey Chapter.Georgia M. Simpson Ms. Simpson joined the Company in 2009, was named Assistant Vice President-Information Technology in January 2019 and promoted to Vice President-Information Technology in July 2019. In April 2022, Ms. Simpson was named Chief Technology Officer. Prior to joining the Company, Ms. Simpson held various Information Technology positions and has gained an extensive array of technical and business computer certifications. Ms. Simpson serves as a member of the Delaware Cyber Security Advisory Council, the Society for Information Management, New Jersey chapter and the Project Management Institute, New Jersey chapter. Bernadette M. Sohler Ms. Sohler joined the Company in 1994 and was named Vice President-Corporate Affairs in March 2007. She also serves as Vice President of USA. Prior to joining the Company, Ms. Sohler held marketing and public relations management positions in the financial services industry. Ms. Sohler serves as a volunteer director on area Chambers of Commerce and several other non-profit Boards and is the former Chair of the New Jersey Utilities Associations Communications Committee.##TABLE_START ITEM 1A. RISK FACTORS. ##TABLE_END Operational Risks Weather conditions and overuse of underground aquifers may interfere with our sources of water, demand for water services and our ability to supply water to customers. Our ability to meet current and future water demands of our customers depends on the availability of an adequate supply of water. Unexpected conditions may interfere with our water supply sources. Drought and overuse of underground aquifers may limit the availability of ground and/or surface water. Freezing weather may also contribute to water transmission interruptions caused by water main breakage. Any interruption in our water supply could cause a reduction in our revenue and profitability. These factors may adversely affect our ability to supply water in sufficient quantities to our customers. Governmental drought restrictions may result in decreased customer demand for water services and can adversely affect our revenue and earnings.Our water sources or water service provided to customers may become contaminated by naturally-occurring or man-made compounds and events. This may cause disruption in services and impose operational and regulatory enforcement costs upon us to restore the water to required levels of quality as well as may damage our reputation and cause private litigation claims against us . Our sources of water or water in our distribution systems may become contaminated by naturally-occurring or man-made compounds or other events. In the event that any portion of our water supply sources or water distribution systems is contaminated, we may need to interrupt service to our customers until we are able to remediate the contamination or substitute the flow of water from an uncontaminated water source through existing interconnections with other water purveyors or through our transmission and distribution systems, where possible. We may also incur significant costs in treating any contaminated water, or remediating the effects on our treatment and distribution systems, through the use of our current treatment facilities, or development of new treatment methods. Our inability to substitute water supply from an uncontaminated water source, or to adequately treat the contaminated water supply in a cost-effective manner, may reduce our revenues or increase our expenses and make us less profitable.We may be unable to recover costs associated with treating water supplies through rates or, recovery of these costs may not occur in a timely manner. In addition, we could be subject to claims for damages arising from government enforcement actions or legal actions arising out of interruption of service or perceived human exposure to hazardous substances in our drinking water and water supplies. Such costs could adversely affect our financial results.Contamination of the water supply or the water service provided to our customers could result in substantial injury or damage to our customers, employees or others and we could be exposed to substantial claims and litigation, which are inherently subject to uncertainties and are potentially subject to unfavorable regulatory and/or legal 12actions. Negative impacts to our profitability and/or our reputation may occur even if we are not responsible for the contamination or the consequences arising out of human exposure to contamination or hazardous substances in the water supplies. Pending or future claims against us could have a material adverse impact on our financial condition, results of operations and cash flows. The necessity for ongoing physical and technological security has resulted, and may continue to result, in increased operating costs. Because of physical and technological threats to the health and security of the United States of America, we employ procedures to review and modify security measures. We provide ongoing training and communications to our employees about threats to our water supply, our assets and related systems and our employees personal safety. We have incurred, and will continue to incur, costs for security measures in efforts to protect against such risks. Climate variability may cause weather volatility in the future, which may impact water usage and related revenue or, may require additional expenditures to reduce risk associated with any increasing storm, flood, drought or other weather occurrences. Increased climate variability may cause increased precipitation and flooding, increased frequency and severity of storms and other weather events, potential degradation of water quality, decreases in available water supply, changes in water usage patterns and disruptions in service. Because of the uncertainty of weather volatility related to climate variability, we cannot predict its potential impact on our financial condition, results of operations, cash flows and liquidity. Although some or all potential expenditures and costs with respect to our regulated businesses could be recovered through rates we charge to our customers, there can be no assurance that the NJBPU or the DEPSC would authorize recovery of such costs, in whole or in part.Regulatory Risks Our revenue and earnings depend on the rates we charge our customers. We cannot raise utility rates in our regulated businesses without petitioning the appropriate Utility Commissions. If these agencies modify, delay or deny our petition, our revenues will not increase and our earnings will decline unless we are able to reduce costs without degrading service quality. The NJBPU regulates our public utility companies in New Jersey with respect to rates and charges for service, classification of accounts, awards of new service territory, acquisitions, financings and other matters. That means, for example, that we cannot raise the utility rates we charge to our customers without first petitioning the NJBPU and navigating a lengthy administrative process. Similarly, the DEPSC regulates our public utility companies in Delaware. We cannot provide assurance as to when we will request approval for any such matter, nor can we predict whether these Utility Commissions will approve, deny or reduce the amount of such requests.Certain costs are not completely within our control. The failure to obtain any rate increase would prevent us from increasing our revenues and, unless we are able to reduce costs without degrading service quality, would result in reduced earnings. We are subject to environmental laws and regulations, including water quality and wastewater effluent quality regulations, as well as other state and local regulations. Compliance with those laws and regulations requires us to incur costs and we are subject to fines or other sanctions for non-compliance. Government environmental regulatory agencies regulate our operations in New Jersey and Delaware with respect to water supply, treatment and distribution systems and the quality of water. Government environmental regulatory agencies also regulate our operations in New Jersey and Delaware with respect to wastewater collection, treatment and disposal.Government environmental regulatory agencies regulations relating to water quality require us to perform expanded types of testing to ensure our water meets state and federal water quality requirements. We are subject to USEPA regulations under the Federal Safe Drinking Water Act and under the Federal Clean Water Act regarding 13wastewater services. Regulations under the Safe Drinking Water Act include the Lead and Copper Rule, the maximum contaminant levels established for various volatile organic compounds, the Federal Surface Water Treatment Rule and the Total Coliform Rule. There are also similar NJDEP regulations for our New Jersey water systems. The NJDEP and DEDPH a monitor our activities and review the results of water quality tests we perform for adherence to applicable regulations. In addition, Government Environmental Regulatory Agencies are continually reviewing regulations governing the limits of certain organic compounds found in the water as byproducts of treatment.We are also subject to regulations related to fire protection services in New Jersey and Delaware. In New Jersey there is no state-wide fire protection regulatory agency. However, New Jersey regulations exist as to the size of piping required regarding the provision of fire protection services. In Delaware, fire protection is regulated statewide by the Office of State Fire Marshal.The cost of compliance with the water and wastewater effluent quality standards depends in part on the limits set in the regulations and on the methods selected to comply with these standards. If new or more restrictive standards are imposed, the cost of compliance could increase and therefore, have an adverse impact on our revenues and results of operations if we cannot recover those costs through the rates we charge our customers. The cost of compliance with fire protection requirements could also increase and make us less profitable if we cannot recover those costs through our rates charged to our customers.The Company must comply with various environmental laws and regulations promulgated by the USEPA, NJDEP and other governmental agencies, including the Toxic Catastrophe Prevention Act, the Spill Prevention, Control, and Countermeasure Rule and the Discharge Prevention Program of the New Jersey Spill Compensation and Control Act. If we fail to comply with environmental or other laws and regulations to which our business is subject, we could be fined or subject to other sanctions, which could adversely impact our business or results of operations. Financial Risks We depend upon our ability to raise money in the capital markets to finance some of the costs of complying with laws and regulations, including environmental laws and regulations or to pay for some of the costs of improvements to or the expansion of our utility system assets. Our regulated utility companies cannot issue debt or equity securities without prior regulatory approval. We require financing from external sources to fund the ongoing capital program for the improvement in our utility system assets and for planned expansion of those systems. We expect to spend approximately $266 million for capital projects through 2025. We must obtain prior approval from our economic regulators to sell debt or equity securities to raise capital for these projects. If sufficient capital is not available, or the cost of capital is too high, or if the regulatory authorities deny our petition to sell debt or equity securities, we may not be able to meet the costs of complying with environmental laws and regulations or the costs of improving and expanding our utility system assets to the level we believe operationally prudent. This may result in the imposition of fines from environmental regulators or restrictions on our operations which could curtail our ability to upgrade or replace utility system assets. We face competition from other utilities and service providers which might hinder our growth opportunities and mitigate our future profitability. We face risks of competition from other utilities or other entities authorized by federal, state or local agencies to expand rate-regulated or contracted utility services. Once a state utility regulator grants a franchise to a public utility to serve a specific territory, that utility effectively has an exclusive right to service that territory. Although a new franchise offers some protection against competitors, the pursuit of franchises is often competitive, particularly in Delaware, where new franchises may be awarded to utilities based upon competitive negotiation. Competing entities have challenged, and may challenge in the future, our applications for new franchises. Also, third parties entering into agreements to operate municipal utility systems may adversely affect the management of our long-term agreements to supply water or wastewater services on a contract basis to those municipalities, which could adversely affect our financial results.14We have short-term and long-term contractual obligations for water, wastewater and storm water system operation and maintenance under which we may incur costs in excess of payments received. USA-PA and USA operate and maintain water and wastewater systems for three New Jersey municipalities under 10-year contracts expiring in 2028, 2030 and 2032, respectively. These contracts do not protect us against incurring costs in excess of revenues we earn pursuant to the contracts.

There can be no absolute assurance we will not experience losses resulting from these contracts. Losses under these contracts, or our failure or inability to perform or renew such agreements, may have a material adverse effect on our financial condition and results of operations.Capital market conditions and key assumptions may adversely impact the value of our postretirement benefit plan assets and liabilities. Market factors can adversely affect the rate of return on assets held in trusts to satisfy our future postretirement benefit obligations, as well negatively affect interest rates, which impacts the discount rates used in the determination of our postretirement benefit actuarial valuations. In addition, changes in demographics, such as increases in life expectancy assumptions, can increase future postretirement benefit obligations. Any negative impact to these factors, either individually or a combination thereof, may have a material adverse effect on our financial condition and results of operations. An element of our growth strategy is the acquisition of water and wastewater assets, operations, contracts or companies. Any pending or future acquisitions we decide to undertake will involve risks. The acquisition and/or operation of water and wastewater systems is an element of our growth strategy. This strategy depends on identifying suitable opportunities that meet our risk/reward profile and reaching mutually agreeable terms with acquisition candidates or contract parties. Further, acquisitions may result in dilution in the value of our equity securities, incurrence of debt and contingent liabilities and fluctuations in financial results. In addition, the assets, operations, contracts or companies we acquire may not achieve the revenues and profitability projected.Our ability to achieve organic customer growth in our market area is dependent on the residential building market. New housing starts and home sale closings are one element that impacts our rate of growth and therefore, may not meet our expectations. We expect our revenues to increase from customer growth for our regulated water operations as a result of anticipated construction, sale and close of new housing units. If housing starts decline, or do not increase as we have projected, or home sales closing cycle times increase as a result of economic conditions or otherwise, the timing and extent of our organic revenue growth may not meet our expectations, our deferred project costs may not produce revenue-generating projects in the timeframes anticipated and our financial results could be negatively impacted.There can be no assurance we will continue to pay dividends in the future or, if dividends are paid, that they will be in amounts similar to past dividends. We have paid dividends on our common stock each year since 1912 and have increased the amount of dividends paid each year since 1973. Our earnings, financial condition, capital requirements, applicable regulations and other factors, including the timeliness and adequacy of rate increases, will determine both our ability to pay dividends and the amount of those dividends. There can be no assurance we will continue to pay dividends in the future or, if dividends are paid, that they will be in amounts similar to past dividends.If we are unable to pay the principal and interest on our indebtedness as it comes due or we default under certain other provisions of our loan documents, our indebtedness could be accelerated and our results of operations and financial condition could be adversely affected. Our ability to pay the principal and interest on our indebtedness as it comes due will depend upon our current and future performance. Our performance is affected by many factors, some of which are beyond our control. 15We believe cash generated from operations and, if necessary, borrowings under existing credit facilities, will be sufficient to enable us to make our debt payments as they become due. If, however, we do not generate sufficient cash, we may be required to refinance our obligations or sell additional equity, which may be on terms that are less favorable than we desire.No assurance can be given that any refinancing or sale of equity will be possible when needed, or that we will be able to negotiate acceptable terms. In addition, our failure to comply with certain provisions contained in our trust indentures and loan agreements relating to our outstanding indebtedness could lead to a default under these documents, which could result in an acceleration of our indebtedness.Our business is subject to seasonal fluctuations, which could affect demand for our water service and our revenues. Demand for our water during the warmer months is generally greater than during colder months due primarily to additional consumption of water in connection with irrigation systems, swimming pools, cooling systems and other outdoor water use. Throughout the year, and particularly during typically warmer months, demand may vary with temperature and rainfall levels. In the event that temperatures during the typically warmer months are cooler than normal, or if there is more rainfall than normal, the demand for our water may decrease and adversely affect our revenues.General economic conditions may materially and adversely affect our financial condition and results of operations. Adverse economic conditions could negatively impact our customers water usage demands, particularly the level of water usage demand by our commercial and industrial customers in our Middlesex System. If water demand by our commercial and industrial customers in our Middlesex System decreases, our financial condition and results of operations could be negatively impacted until completion of a subsequent base rate filing.The current concentration of our business in central New Jersey and in Delaware makes us susceptible to adverse developments in local regulatory, economic, demographic, competitive and weather conditions. Our Middlesex System provides water services to customers located primarily in eastern Middlesex County, New Jersey. Water service is provided under wholesale contracts to the Townships of Edison, East Brunswick and Marlboro, the Borough of Highland Park, the Old Bridge Municipal Utilities Authority and the City of Rahway. We also provide water services to customers in the State of Delaware. Our revenues and operating results are therefore subject to local regulatory, economic, demographic, competitive and weather conditions in a relatively concentrated geographic area. A change in any of these conditions could make it more costly for us to conduct our business.We are subject to anti-takeover measures that may be used to discourage, delay or prevent changes of control that might benefit non-management shareholders. Subsection 10A of the New Jersey Business Corporation Act, known as the New Jersey Shareholders Protection Act, applies to us. The Shareholders Protection Act deters merger proposals, tender offers or other attempts to effect changes in control that are not approved by our Board of

Directors. In addition, we have a classified Board of Directors, which means only a portion of the Director population is elected each year. A classified Board can make it more difficult for an acquirer to gain control of the Company by voting its candidates onto the Board of Directors and may also deter merger proposals and tender offers. Our Board of Directors also has the ability, subject to obtaining NJBPU approval, to issue one or more series of preferred stock having such number of shares, designation, preferences, voting rights, limitations and other rights as the Board of Directors may fix. This could be used by the Board of Directors to discourage, delay or prevent an acquisition the Board of Directors determines is not in the best interest of the common shareholders.16 General Risks We rely on our information technology systems to help manage our operations. Our information technology systems require periodic modifications, upgrades and/or replacement which subject us to costs and risks including potential disruption of our internal control structure, substantial unanticipated capital expenditures, additional operating expenses, retention of sufficiently skilled personnel and other risks in transitioning to new systems or integrating new systems. A failure to modify, upgrade or replace our information technology systems could have an adverse impact on our business. In addition, challenges implementing new technology systems may cause disruptions in our business operations and have an adverse effect on our business operations.Our information technology systems may be subject to physical and cyber attacks. We rely on our computer, information and communications technology systems in connection with the operation of our business, especially with respect to customer service and billing, accounting and, in some cases, the monitoring and operation of our operating facilities. Our computer and communications systems and operations could be damaged or interrupted by natural disasters, cyber-attacks, power loss and internet, telecommunications or data network failures or acts of war or terrorism or similar events or disruptions. Any of these or other events could cause service interruption, delays and loss of critical data or, impede aspects of operations and therefore, adversely affect our financial results.Cyber-attacks could result in the loss, or compromise, of customer, financial or operational data, disruption of billing, collections or normal field service activities, disruption of electronic monitoring and control of operational systems and delays in financial reporting and other management functions. Possible impacts associated with a cyber-incident may include remediation costs related to lost, stolen, or compromised data, repairs to data processing systems, increased cyber security protection costs, adverse effects on our compliance with regulatory and environmental laws and regulations, including standards for drinking water, litigation and reputational damage.The COVID-19 pandemic and the attempt to contain it may harm our business, results of operations, financial condition and liquidity. In January 2023, the United States Secretary of Health and Human Services renewed the determination that a nationwide health emergency exists as a result of the COVID-19 Pandemic with an announced end to the declared health emergency on May 11, 2023. While the Companys operations and capital construction program have not been materially disrupted to date from the pandemic, the impact on economic conditions nationally and the areas the Company operates continues to be uncertain and could affect the Companys results of operations, financial condition and liquidity in the future. We depend significantly on the technical and management services of our team, and the departure of any of certain persons could cause our operating results to temporarily be short of our expectations. Our success depends significantly on the continued individual and collective contributions of our team. If we lose the services of certain members of our team, or are unable to attract and retain qualified personnel in key roles, our operating results could be negatively impacted.##TABLE_START

Ticker: MSEX, Sector: Utilities, Filed At: 2023-11-08T16:34:50-05:00

ITEM 1A. RISK FACTORS. ##TABLE_END Operational Risks Weather conditions and overuse of underground aquifers may interfere with our sources of water, demand for water services and our ability to supply water to customers. Our ability to meet current and future water demands of our customers depends on the availability of an adequate supply of water. Unexpected conditions may interfere with our water supply sources. Drought and overuse of underground aquifers may limit the availability of ground and/or surface water. Freezing weather may also contribute to water transmission interruptions caused by water main breakage. Any interruption in our water supply could cause a reduction in our revenue and profitability. These factors may adversely affect our ability to supply water in sufficient quantities to our customers. Governmental drought restrictions may result in decreased customer demand for water services and can adversely affect our revenue and earnings. Our water sources or water service provided to customers may become contaminated by naturally-occurring or man-made compounds and events. This may cause disruption in services and impose operational and regulatory enforcement costs upon us to restore the water to required levels of quality as well as may damage our reputation and cause private litigation claims against us . Our sources of water or water in our distribution systems may become contaminated by naturally-occurring or man-made compounds or other events. In the event that any portion of our water supply sources or water distribution systems is contaminated, we may need to interrupt service to our customers until we are able to remediate the contamination or substitute the flow of water from an uncontaminated water source through existing interconnections with other water purveyors or through our transmission and distribution systems, where possible. We may also incur significant costs in treating any contaminated water, or remediating the effects on our treatment and distribution systems, through the use of our current treatment facilities, or development of new treatment methods. Our inability to substitute water supply from an uncontaminated water source, or to adequately treat the contaminated water supply in a cost-effective manner, may reduce our revenues or increase our expenses and make us less profitable. We may be unable to recover costs associated with treating water supplies through rates or, recovery of these costs may not occur in a timely manner. In addition, we could be subject to claims for damages arising from government enforcement actions or legal actions arising out of interruption of service or perceived human exposure to hazardous substances in our drinking water and water supplies. Such costs could adversely affect our financial results. Contamination of the water supply or the water service provided to our customers could result in substantial injury or damage to our customers, employees or others and we could be exposed to substantial claims and litigation, which are inherently subject to uncertainties and are potentially subject to unfavorable regulatory and/or legal actions. Negative impacts to our profitability and/or our reputation may occur even if we are not responsible for the contamination or the consequences arising out of human exposure to contamination or hazardous substances in the water supplies. Pending or future claims against us could have a material adverse impact on our financial condition, results of operations and cash flows. The necessity for ongoing physical and technological security has resulted, and may continue to result, in increased operating costs. Because of physical and technological threats to the health and security of the United States of America, we employ procedures to review and modify security measures. We provide ongoing training and communications to our employees about threats to our water supply, our assets and related systems and our employees personal safety. We have incurred, and will continue to incur, costs for security measures in efforts to protect against such risks. Climate variability may cause weather volatility in the future, which may impact water usage and related revenue or, may require additional expenditures to reduce risk associated with any increasing storm, flood, drought or other weather occurrences. Increased climate variability may cause increased precipitation and flooding, increased frequency and severity of storms and other weather events, potential degradation of water quality, decreases in available water supply, changes in water usage patterns and disruptions in service. Because of the uncertainty of weather volatility related to climate variability, we cannot predict its potential impact on our financial condition, results of operations, cash flows and liquidity. Although some or all potential expenditures and costs with respect to our regulated businesses could be recovered through rates we charge to our customers, there can be no assurance that the NJBPU or the DEPSC would authorize recovery of such costs, in whole or in part. Regulatory Risks Our revenue and earnings depend on the rates we charge our customers. We cannot raise utility rates in our regulated businesses without petitioning the appropriate Utility Commissions. If these agencies modify, delay or deny our petition, our revenues will not increase and our earnings will decline unless we are able to reduce costs without degrading service quality. The NJBPU regulates our public utility companies in New Jersey with respect to rates and charges for service, classification of accounts, awards of new service territory, acquisitions, financings and other matters. That means, for example, that we cannot raise the utility rates we charge to our customers without first petitioning the NJBPU and navigating a lengthy administrative process. Similarly, the DEPSC regulates our public utility companies in Delaware. We cannot provide assurance as to when we will request approval for any such matter, nor can we predict whether these Utility Commissions will approve, deny or reduce the amount of such requests. Certain costs are not completely within our control. The failure to obtain any rate increase would prevent us from increasing our revenues and, unless we are able to reduce costs without degrading service quality, would result in reduced earnings. We are subject to environmental laws and regulations, including water quality and wastewater effluent quality regulations, as well as other state and local regulations. Compliance with those laws and regulations requires us to incur costs and we are subject to fines or other sanctions for non-compliance. Government environmental regulatory agencies regulate our operations in New Jersey and Delaware with respect to water supply, treatment and distribution systems and the quality of water. Government environmental regulatory agencies also regulate our operations in New Jersey and Delaware with respect to wastewater collection, treatment and disposal. Government environmental regulatory agencies regulations relating to water quality require us to perform expanded types of testing to ensure our water meets state and federal water quality requirements. We are subject to USEPA regulations under the Federal Safe Drinking Water Act and under the Federal Clean Water Act regarding wastewater services. Regulations under the Safe Drinking Water Act include the Lead and Copper Rule, the maximum contaminant levels established for various volatile organic compounds, the Federal Surface Water Treatment Rule and the Total Coliform Rule. There are also similar NJDEP regulations for our New Jersey water systems. The NJDEP and DEDPH a monitor our activities and review the results of water quality tests we perform for adherence to applicable regulations. In addition, Government Environmental Regulatory Agencies are continually reviewing regulations governing the limits of certain organic compounds found in the water as byproducts of treatment. We are also subject to regulations related to fire protection services in New Jersey and Delaware. In New Jersey there is no state-wide fire protection regulatory agency. However, New Jersey regulations exist as to the size of piping required regarding the provision of fire protection services. In Delaware, fire protection is regulated statewide by the Office of State Fire Marshal. The cost of compliance with the water and wastewater effluent quality standards depends in part on the limits set in the regulations and on the methods selected to comply with these standards. If new or more restrictive standards are imposed, the cost of compliance could increase and therefore, have an adverse impact on our revenues and results of operations if we cannot recover those costs through the rates we charge our customers. The cost of compliance with fire protection requirements could also increase and make us less profitable if we cannot recover those costs through our rates charged to our customers. The Company must comply with various environmental laws and regulations promulgated by the USEPA, NJDEP and other governmental agencies, including the Toxic Catastrophe Prevention Act, the Spill Prevention, Control, and Countermeasure Rule and the Discharge Prevention Program of the New Jersey Spill Compensation and Control Act. If we fail to comply with environmental or other laws and regulations to which our business is subject, we could be fined or subject to other sanctions, which could adversely impact our business or results of operations. Financial Risks We depend upon our ability to raise money in the capital markets to finance some of the costs of complying with laws and regulations, including environmental laws and regulations or to pay for some of the costs of improvements to or the expansion of our utility system assets. Our regulated utility companies cannot issue debt or equity securities without prior regulatory approval. We require financing from external sources to fund the ongoing capital program for the improvement in our utility system assets and for planned expansion of those systems. We expect to spend approximately $266 million for capital projects through 2025. We must obtain prior approval from our economic regulators to sell debt or equity securities to raise capital for these projects. If sufficient capital is not available, or the cost of capital is too high, or if the regulatory authorities deny our petition to sell debt or equity securities, we may not be able to meet the costs of complying with environmental laws and regulations or the costs of improving and expanding our utility system assets to the level we believe operationally prudent. This may result in the imposition of fines from environmental regulators or restrictions on our operations which could curtail our ability to upgrade or replace utility system assets. We face competition from other utilities and service providers which might hinder our growth opportunities and mitigate our future profitability. We face risks of competition from other utilities or other entities authorized by federal, state or local agencies to expand rate-regulated or contracted utility services. Once a state utility regulator grants a franchise to a public utility to serve a specific territory, that utility effectively has an exclusive right to service that territory. Although a new franchise offers some protection against competitors, the pursuit of franchises is often competitive, particularly in Delaware, where new franchises may be awarded to utilities based upon competitive negotiation. Competing entities have challenged, and may challenge in the future, our applications for new franchises. Also, third parties entering into agreements to operate municipal utility systems may adversely affect the management of our long-term agreements to supply water or wastewater services on a contract basis to those municipalities, which could adversely affect our financial results. We have short-term and long-term contractual obligations for water, wastewater and storm water system operation and maintenance under which we may incur costs in excess of payments received. USA-PA and USA operate and maintain water and wastewater systems for three New Jersey municipalities under 10-year contracts expiring in 2028, 2030 and 2032, respectively. These contracts do not protect us against incurring costs in excess of revenues we earn pursuant to the contracts. There can be no absolute assurance we will not experience losses resulting from these contracts. Losses under these contracts, or our failure or inability to perform or renew such agreements, may have a material adverse effect on our financial condition and results of operations. Capital market conditions and key assumptions may adversely impact the value of our postretirement benefit plan assets and liabilities. Market factors can adversely affect the rate of return on assets held in trusts to satisfy our future postretirement benefit obligations, as well negatively affect interest rates, which impacts the discount rates used in the determination of our postretirement benefit actuarial valuations. In addition, changes in demographics, such as increases in life expectancy assumptions, can increase future postretirement benefit obligations. Any negative impact to these factors, either individually or a combination thereof, may have a material adverse effect on our financial condition and results of operations. An element of our growth strategy is the acquisition of water and wastewater assets, operations, contracts or companies. Any pending or future acquisitions we decide to undertake will involve risks. The acquisition and/or operation of water and wastewater systems is an element of our growth strategy. This strategy depends on identifying suitable opportunities that meet our risk/reward profile and reaching mutually agreeable terms with acquisition candidates or contract parties. Further, acquisitions may result in dilution in the value of our equity securities, incurrence of debt and contingent liabilities and fluctuations in financial results. In addition, the assets, operations, contracts or companies we acquire may not achieve the revenues and profitability projected. Our ability to achieve organic customer growth in our market area is dependent on the residential building market. New housing starts and home sale closings are one element that impacts our rate of growth and therefore, may not meet our expectations. We expect our revenues to increase from customer growth for our regulated water operations as a result of anticipated construction, sale and close of new housing units. If housing starts decline, or do not increase as we have projected, or home sales closing cycle times increase as a result of economic conditions or otherwise, the timing and extent of our organic revenue growth may not meet our expectations, our deferred project costs may not produce revenue-generating projects in the timeframes anticipated and our financial results could be negatively impacted. There can be no assurance we will continue to pay dividends in the future or, if dividends are paid, that they will be in amounts similar to past dividends. We have paid dividends on our common stock each year since 1912 and have increased the amount of dividends paid each year since 1973. Our earnings, financial condition, capital requirements, applicable regulations and other factors, including the timeliness and adequacy of rate increases, will determine both our ability to pay dividends and the amount of those dividends. There can be no assurance we will continue to pay dividends in the future or, if dividends are paid, that they will be in amounts similar to past dividends. If we are unable to pay the principal and interest on our indebtedness as it comes due or we default under certain other provisions of our loan documents, our indebtedness could be accelerated and our results of operations and financial condition could be adversely affected. Our ability to pay the principal and interest on our indebtedness as it comes due will depend upon our current and future performance. Our performance is affected by many factors, some of which are beyond our control. We believe cash generated from operations and, if necessary, borrowings under existing credit facilities, will be sufficient to enable us to make our debt payments as they become due. If, however, we do not generate sufficient cash, we may be required to refinance our obligations or sell additional equity, which may be on terms that are less favorable than we desire. No assurance can be given that any refinancing or sale of equity will be possible when needed, or that we will be able to negotiate acceptable terms. In addition, our failure to comply with certain provisions contained in our trust indentures and loan agreements relating to our outstanding indebtedness could lead to a default under these documents, which could result in an acceleration of our indebtedness. Our business is subject to seasonal fluctuations, which could affect demand for our water service and our revenues. Demand for our water during the warmer months is generally greater than during colder months due primarily to additional consumption of water in connection with irrigation systems, swimming pools, cooling systems and other outdoor water use. Throughout the year, and particularly during typically warmer months, demand may vary with temperature and rainfall levels. In the event that temperatures during the typically warmer months are cooler than normal, or if there is more rainfall than normal, the demand for our water may decrease and adversely affect our revenues. General economic conditions may materially and adversely affect our financial condition and results of operations. Adverse economic conditions could negatively impact our customers water usage demands, particularly the level of water usage demand by our commercial and industrial customers in our Middlesex System. If water demand by our commercial and industrial customers in our Middlesex System decreases, our financial condition and results of operations could be negatively impacted until completion of a subsequent base rate filing. The current concentration of our business in central New Jersey and in Delaware makes us susceptible to adverse developments in local regulatory, economic, demographic, competitive and weather conditions. Our Middlesex System provides water services to customers located primarily in eastern Middlesex County, New Jersey. Water service is provided under wholesale contracts to the Townships of Edison, East Brunswick and Marlboro, the Borough of Highland Park, the Old Bridge Municipal Utilities Authority and the City of Rahway. We also provide water services to customers in the State of Delaware. Our revenues and operating results are therefore subject to local regulatory, economic, demographic, competitive and weather conditions in a relatively concentrated geographic area. A change in any of these conditions could make it more costly for us to conduct our business. We are subject to anti-takeover measures that may be used to discourage, delay or prevent changes of control that might benefit non-management shareholders. Subsection 10A of the New Jersey Business Corporation Act, known as the New Jersey Shareholders Protection Act, applies to us. The Shareholders Protection Act deters merger proposals, tender offers or other attempts to effect changes in control that are not approved by our Board of Directors. In addition, we have a classified Board of Directors, which means only a portion of the Director population is elected each year. A classified Board can make it more difficult for an acquirer to gain control of the Company by voting its candidates onto the Board of Directors and may also deter merger proposals and tender offers. Our Board of Directors also has the ability, subject to obtaining NJBPU approval, to issue one or more series of preferred stock having such number of shares, designation, preferences, voting rights, limitations and other rights as the Board of Directors may fix. This could be used by the Board of Directors to discourage, delay or prevent an acquisition the Board of Directors determines is not in the best interest of the common shareholders. We identified a material weakness in our internal control related to ineffective information technology general controls which, if not remediated appropriately or timely, could result in loss of investor confidence and adversely impact our stock price. Internal controls related to the operation of technology systems are critical to maintaining adequate internal control over financial reporting. During the fourth quarter of 2023, management identified a material weakness in internal control related to ineffective information technology general controls (ITGCs) in the areas of user access and change management over certain information technology (IT) systems that support the Companys financial reporting processes. Certain of those controls were found to be deficient because of a lack of sufficient IT control processes designed to prevent or detect unauthorized changes in applications and data in selected IT environments. As a result, management concluded that our internal control over financial reporting was not effective as of December 31, 2022. Although we are working towards implementing remediation measures prior to the end of 2023, until remediation measures are completed, tested and determined effective, we will not be able to conclude that the material weakness has been remediated. If we are unable to determine that our remediation measures are effective or otherwise remediate the material weakness, or are otherwise unable to maintain effective internal control over financial reporting or disclosure controls and procedures, our ability to record, process and report financial information accurately, and to prepare financial statements within required time periods, could be adversely affected, which could subject us to litigation or investigations requiring management resources and payment of legal and other expenses, negatively affecting investor confidence in our financial statements and adversely impacting our stock price. General Risks We rely on our information technology systems to help manage our operations. Our information technology systems require periodic modifications, upgrades and/or replacement which subject us to costs and risks including potential disruption of our internal control structure, substantial unanticipated capital expenditures, additional operating expenses, retention of sufficiently skilled personnel and other risks in transitioning to new systems or integrating new systems. A failure to modify, upgrade or replace our information technology systems could have an adverse impact on our business. In addition, challenges implementing new technology systems may cause disruptions in our business operations and have an adverse effect on our business operations. Our information technology systems may be subject to physical and cyber attacks. We rely on our computer, information and communications technology systems in connection with the operation of our business, especially with respect to customer service and billing, accounting and, in some cases, the monitoring and operation of our operating facilities. Our computer and communications systems and operations could be damaged or interrupted by natural disasters, cyber-attacks, power loss and internet, telecommunications or data network failures or acts of war or terrorism or similar events or disruptions. Any of these or other events could cause service interruption, delays and loss of critical data or, impede aspects of operations and therefore, adversely affect our financial results. Cyber-attacks could result in the loss, or compromise, of customer, financial or operational data, disruption of billing, collections or normal field service activities, disruption of electronic monitoring and control of operational systems and delays in financial reporting and other management functions. Possible impacts associated with a cyber-incident may include remediation costs related to lost, stolen, or compromised data, repairs to data processing systems, increased cyber security protection costs, adverse effects on our compliance with regulatory and environmental laws and regulations, including standards for drinking water, litigation and reputational damage. The COVID-19 pandemic and the attempt to contain it may harm our business, results of operations, financial condition and liquidity. In January 2023, the United States Secretary of Health and Human Services renewed the determination that a nationwide health emergency exists as a result of the COVID-19 Pandemic with an announced end to the declared health emergency on May 11, 2023. While the Companys operations and capital construction program have not been materially disrupted to date from the pandemic, the impact on economic conditions nationally and the areas the Company operates continues to be uncertain and could affect the Companys results of operations, financial condition and liquidity in the future. We depend significantly on the technical and management services of our team, and the departure of any of certain persons could cause our operating results to temporarily be short of our expectations. Our success depends significantly on the continued individual and collective contributions of our team. If we lose the services of certain members of our team, or are unable to attract and retain qualified personnel in key roles, our operating results could be negatively impacted. ##TABLE_START

Ticker: NFE, Sector: Utilities, Filed At: 2023-03-01T13:46:49-05:00

Items 1 and 2. Business and Properties Unless the context otherwise requires, references in this Annual Report to the Company, NFE, we, our, us or like terms refer to New Fortress Energy Inc. and its subsidiaries. When used in a historical context, prior to completion of Mergers (as defined herein), Company, we, our, us or like terms refer to New Fortress Energy Inc. and its subsidiaries, excluding Hygo Energy Transition Ltd. (Hygo) and its subsidiaries and Golar LNG Partners LP (GMLP) and its subsidiaries; and after completion of the Mergers, Company, we, our, us or like terms refer to New Fortress Energy Inc. and its subsidiaries, including Hygo and its subsidiaries and GMLP and its subsidiaries. Overview We are a global energy infrastructure company founded to help address energy poverty and accelerate the world's transition to reliable, affordable and clean energy. We own and operate natural gas and liquefied natural gas ("LNG") infrastructure, and an integrated fleet of ships and logistics assets to rapidly deliver turnkey energy solutions to global markets; additionally, we have expanded our focus to building our modular LNG manufacturing business. Our near-term mission is to provide modern infrastructure solutions to create cleaner, reliable energy while generating a positive economic impact worldwide. Our long-term mission is to become one of the worlds leading companies providing power free from carbon emissions by leveraging our global portfolio of integrated energy infrastructure. We discuss this important goal in more detail below under SustainabilityToward a Very-Low-Carbon Future. We deliver targeted energy solutions by employing an integrated LNG supply and delivery model: LNG and Natural Gas Supply and Liquefaction We supply LNG and natural gas to our own power plants and to our customers. We typically supply LNG and natural gas regasified from LNG to our customers by entering into long-term supply contracts, which are generally based on an index such as Henry Hub plus a fixed fee component. We acquire our LNG from third party suppliers in open market purchases and long term supply agreements; we also manufacture LNG at our liquefaction and storage facility in Miami, Florida (the Miami Facility). Beginning in 2023, we expect to deploy our first offshore liquefaction facility, "Fast LNG" or "FLNG," to provide a source of low-cost supply of LNG. Shipping We own or operate a fleet of seven regasification units (FSRUs) and eleven liquefied natural gas carriers (LNGCs) and floating storage units (FSUs). Ten vessels are owned by our joint venture affiliate, Energos, and two are owned by NFE, We also charter vessels to and from third parties as well as from Energos. Facilities Through our network of current and planned downstream facilities and logistics assets, we are strategically positioned to deliver gas and power solutions to our customers seeking either to transition from environmentally dirtier distillate fuels such as automotive diesel oil (ADO) and heavy fuel oil (HFO) or to purchase natural gas to meet their current fuel needs. We analyze and seek to implement innovative and new technologies that complement our businesses to reduce our costs, achieve efficiencies for our business and our customers and advance our long-term goals, such as our ISO container distribution system, our Fast LNG solution and our hydrogen project. Our Business Model As an integrated gas-to-power energy infrastructure company, our business model spans the entire production and delivery chain from natural gas procurement and liquefaction to shipping, logistics, facilities and conversion or development of natural gas-fired power generation. Historically, natural gas procurement or liquefaction, transportation, regasification and power generation projects have been developed separately and have required multilateral or traditional financing sources, which has inhibited the introduction of natural gas-fired power in many developing countries. In executing our business model, we have the capability to build or arrange any necessary infrastructure ourselves without reliance on multilateral financing sources or traditional project finance structures, so that we maintain our strategic flexibility and optimize our portfolio. We currently conduct our operations at the following facilities: our LNG storage and regasification facility at the Port of Montego Bay, Jamaica (the Montego Bay Facility), our marine LNG storage and regasification facility in Old Harbour, Jamaica (the Old Harbour Facility and, together with the Montego Bay Facility, the Jamaica Facilities), our landed micro-fuel handling facility in San Juan, Puerto Rico (the San Juan Facility), our LNG receiving facility in La Paz, Mexico (the La Paz Facility), and at our Miami Facility. In addition, we are currently developing facilities in Brazil, Nicaragua, Ireland and other locations, as described below in more detail. We are in active discussions with additional customers to develop projects in multiple regions around the world who may have significant demand for additional power, LNG and natural gas, although there can be no assurance that these discussions will result in additional contracts or that we will be able to achieve our target pricing or margins. Our Facilities We look to build facilities in locations where the need for LNG is significant. We design and construct LNG and power facilities to meet the supply and demand specifications of our current and potential future customers in the applicable region. In these markets, we first seek to identify and establish beachhead target markets for the sale of LNG, natural gas or natural gas-fired power. We then seek to convert and supply natural gas to additional power customers. Finally, our goal is to expand within the market by supplying additional industrial and transportation customers. Our facilities position us to acquire and supply LNG to customers and natural gas-fired power in a number of attractive markets around the world. Downstream, we have thirteen facilities that are either operational or under active development. We currently have four operational LNG terminal facilities and four under active development, as well as one operational power plant facilities and four under active development, as described below. Our LNG facilities currently operating or under development are expected to be capable of receiving up to 800,000 MMBtu from LNG per day depending upon the needs of our customers and potential demand in the region. Set forth below is additional detail regarding each of our LNG and power facilities: Montego Bay, Jamaica Our Montego Bay Facility commenced commercial operations in October 2016. The Montego Bay Facility is capable of processing up to 61,000 MMBtu from LNG per day and features approximately 7,000 cubic meters of onsite storage. It supplies natural gas to the 145MW power plant (the Bogue Power Plant) operated by Jamaica Public Service Company Limited (JPS) pursuant to a long-term contract for natural gas equivalent to approximately 25,600 MMBtu from LNG per day. The Montego Bay Facility also supplies numerous on-island industrial users with natural gas or LNG pursuant to offtake contracts of various durations. We have total aggregate contracted volumes of approximately 29,000 MMBtu from LNG per day at our Montego Bay Facility with a weighted average remaining contract length of 17 years as of December 31, 2022. We have the ability to service other potential customers with the excess capacity of the Montego Bay Facility, and we are seeking to enter into long-term contracts with new customers for such purposes. Old Harbour, Jamaica Our Old Harbour Facility commenced commercial operations in June 2019. The Old Harbour Facility is an offshore facility with storage and regasification equipment provided via FSRU. The offshore design eliminates the need for onshore infrastructure and storage tanks. It is capable of processing approximately 750,000 MMBtu from LNG per day. The Old Harbour Facility is supplying gas to a 190MW gas-fired power plant (the Old Harbour Power Plant) owned and operated by South Jamaica Power Company Limited (SJPC) pursuant to a long-term contract for natural gas equivalent to approximately 30,000 MMBtu from LNG per day, and back-up ADO, for 20 years. The Old Harbour Facility is also supplying gas to our 150MW dual-fired combined heat and power (CHP) facility in Clarendon, Jamaica (the CHP Plant), which we constructed, and which commenced commercial operations in March 2020. The CHP Plant is fueled by natural gas, with the ability to run on ADO as a backup fuel source. We have executed a suite of agreements in connection with the CHP Plant, including a 20-year agreement to supply steam to an alumina refinery joint venture between affiliates of Noble Group, and the Government of Jamaica, and we have a 20-year agreement to supply electricity to JPS. We have total aggregate contracted volumes of approximately 58,000 MMBtu from LNG per day at our Old Harbour Facility with a weighted average contract length of 17 years as of December 31, 2022. We have the ability to service other potential customers with the excess capacity of the Old Harbour Facility, and we are seeking to enter into long-term contracts with new customers for such purposes. San Juan, Puerto Rico Our San Juan Facility became fully operational in the third quarter of 2020. It is designed as a landed micro-fuel handling facility located in the Port of San Juan, Puerto Rico. The San Juan Facility has multiple truck loading bays to provide LNG to on-island industrial users. In addition, it supplies natural gas to Units 5 and 6 of the San Juan combined cycle power plant (the PREPA San Juan Power Plant), which are owned and operated by the Puerto Rico Electric Power Authority (PREPA), a public instrumentality of the government of Puerto Rico. We converted Units 5 and 6, which together have a capacity of 440MW, to use natural gas as fuel and expect to supply both Units 5 and 6 with approximately 68,600 MMBtu from LNG per day. La Paz, Baja California Sur, Mexico Our La Paz Facility commenced operations in the second quarter of 2021. It is an LNG receiving facility located at the Port of Pichilingue in Baja California Sur, Mexico, receiving LNG via ISO containers on an offshore supply vehicle from a nearby vessel. The La Paz Facility is expected to supply approximately 22,300 MMBtu from LNG per day to our gas-fired modular power units located in La Paz (the La Paz Power Plant) for approximately 100MW of power following the start of operations. In addition, in March 2021, we entered into a gas sales agreement with CFEnergia ("CFE"), a subsidiary of Federal Electricity Commission (Comisin Federal de Electricidad), Mexicos power utility, for the supply of natural gas to power plants located at Punta Prieta and Coromuel in the State of Baja California Sur ("CFE Plants"), and in the fourth quarter of 2022, we reached an agreement to expand and extend our supply of natural gas to multiple CFE power generation facilities in Baja California Sur. We expect to sell approximately 41,000 MMBtu from LNG per day under an amended gas sales agreement with CFE. Puerto Sandino, Nicaragua We are developing an offshore facility in Puerto Sandino, Nicaragua, consisting of an FSRU and associated infrastructure, including mooring and offshore pipelines (the Puerto Sandino Facility). The Puerto Sandino Facility is expected to supply gas to our new approximately 300MW natural gas-fired power plant in Puerto Sandino, Nicaragua (the Nicaragua Power Plant) that we will own and operate. We have entered into a 25-year power purchase agreement with Nicaraguas electricity distribution companies. We expect to utilize approximately 57,500 MMBtu from LNG per day to provide natural gas to the Puerto Sandino Power Plant in connection with the 25-year power purchase agreement. As part of our long-term partnership with the local utility, we are evaluating solutions to optimize power generation efficiency and allow for additional electrical capacity in a market that is underserved. We expect to complete this optimization in 2024. Barcarena, Brazil Our terminal in the State of Par, Brazil (the Barcarena Facility) consists of an FSRU and associated infrastructure, including mooring and offshore and onshore pipelines. The Barcarena Facility is capable of processing up to 790,000 MMBtu from LNG per day and storing up to 170,000 cubic meters of LNG. We anticipate that the Barcarena Facility will be anchored by several large-scale industrial and power customer contracts, including gas supply to our new 605MW combined cycle thermal power plant to be located in Par, Brazil (the Barcarena Power Plant). The power plant is supported by multiple 25-year power purchase agreements to supply electricity to the national electricity grid. The Barcarena Power Plant is scheduled to deliver power to nine committed offtakers for 25 years beginning in 2025. We have entered into a 15-year gas supply agreement with a subsidiary of Norsk Hydro ASA for the supply of natural gas to the Alunorte Alumina Refinery in Par, Brazil, through our Barcarena Facility. We substantially completed our Barcarena Facility in 2022 and expect to commence operations, including delivery to the Alunorte Alumina Refinery by the end of 2023. We expect to complete the Barcarena Power Plant and to commence operations in 2025. Santa Catarina, Brazil Our facility in Santa Catarina, Brazil (the Santa Catarina Facility and, together with the Barcarena Facility, the "Brazil Facilities") will be located on the southern coast of Brazil and will consist of an FSRU with a processing capacity of approximately 570,000 MMBtu from LNG per day and LNG storage capacity of up to 170,000 cubic meters. We are also developing a 33-kilometer, 20-inch pipeline that will connect the Santa Catarina Facility to the existing inland Transportadora Brasileira Gasoduto Bolivia-Brasil S.A. (TBG) pipeline via an interconnection point in the municipality of Garuva. The Santa Catarina Facility and associated pipeline are expected to have a total addressable market of 1,2 million MMBtu from LNG per day. We expect to complete our Santa Catarina Facility and commence operations in 2023. Shannon, Ireland We intend to develop and operate an LNG facility (the Ireland Facility and, together with the Jamaica Facilities, the San Juan Facility, the Brazil Facilities, the La Paz Facility and the Puerto Sandino Facility, our LNG Facilities) and a power plant on the Shannon Estuary, near Tarbert, Ireland (the Ireland Power Plant and, together with the CHP Plant, La Paz Power Plant, Nicaragua Power Plant, Barcarena Power Plant, the Power Plants, and together with the LNG Facilities, the Facilities). We are in the process of obtaining final planning permission from An Bord Pleanla (ABP) in Ireland, and we have undertaken pre-development work that will allow us to complete the Ireland Facility in approximately 9 to 15 months after receiving requisite permits. We currently expect to begin operations in the first half of 2024. LNG Supply NFE provides reliable, affordable and clean energy supplies to customers around the world that we plan to satisfy through the following sources: 1) our current contractual supply commitments; 2) additional LNG supply contracts expected to commence in 2026; 3) our Miami Facility; and 4) our own Fast LNG production. We have secured commitments to purchase and receive physical delivery of LNG volumes for 100% of our expected committed volumes for each of our downstream terminals inclusive of our Montego Bay Facility, Old Harbour Facility, San Juan Facility, La Paz Facility, Puerto Sandino Facility, Barcarena Facility and Santa Catarina Facility. Additionally, we have binding contracts for LNG volumes from two separate U.S. LNG facilities, each with a 20-year term, that are expected to commence in 2026 and 2027. Finally, we plan to commence our Fast LNG production in 2023, when our first FLNG facility is expected to begin operation, and we plan to expand that capacity when additional units come online over the next two years. The majority of our LNG supply contracts are based on a natural gas-based index, Henry Hub, plus a contractual spread. We limit our exposure to fluctuations in natural gas prices as our pricing in contracts with customers is largely based on the Henry Hub index price plus a fixed fee component. Additionally, with our own Fast LNG production expected to commence in 2023, we plan to further mitigate our exposure to variability in LNG prices. Due to current market conditions, we expect that our revenue and results of operations will benefit in the near term from selling cargos into the global LNG market. As FLNG facilities commence production, our long-term strategy is to sell substantially all cargos produced to customers on a long-term, take-or-pay basis through our downstream terminals. Liquefaction Assets We constructed the Miami Facility, which commenced full commercial operations in 2016, in fewer than 12 months, at a cost to build of approximately $70 million. The Miami Facility has one liquefaction train, with liquefaction production capacity of approximately 8,300 MMBtu from LNG per day and was 98% dispatchable during 2022. The Miami Facility also has three LNG storage tanks, with total capacity of approximately 1,000 cubic meters. The Miami Facility also includes two separate LNG transfer areas capable of serving both truck and rail. For the fiscal year ended December 31, 2022, we delivered approximately 8,200 MMBtu from LNG per day from the Miami Facility pursuant to long-term take-or-pay contracts. Fast LNG (FLNG) We are currently developing multiple modular floating liquefaction facilities to provide a source of low-cost supply of LNG. We have designed and are constructing offshore liquefaction facilities for our growing customer base that we believe are both faster and more economical to construct than many traditional liquefaction solutions. The Fast LNG, or FLNG, design pairs advancements in modular, midsize liquefaction technology with jack up rigs, semi-submersible rigs or similar marine floating infrastructure to enable a lower cost and faster deployment schedule than land-based alternatives. Semi-permanently moored floating storage unit(s) (FSUs) will provide LNG storage alongside the floating liquefaction infrastructure, which can be deployed anywhere there is abundant and stranded natural gas. Fast LNG is anchored by key benefits over conventional liquefaction projects. In particular, we believe installing modular equipment in a shipyard will meaningfully expedite timelines. In addition, placing each solution offshore will provide greater access to natural gas and optimized marine logistics. Fast LNG solutions are also flexible from a commercial standpoint, as they can act as tolling facilities (where third parties are the offtaker of the LNG), manufacturing facilities (where we are the offtaker), or a combination of the two. This flexibility enables us to take advantage of numerous opportunities around the world and present the most optimal commercial arrangements for us and our counterparties. Our initial Fast LNG units are being constructed at the Kiewit Offshore Services shipyard near Corpus Christi, Texas. The Kiewit facility specializes in the fabrication and integration of offshore projects. In partnership with Kiewit, we believe we have established an efficient and repeatable process to reduce cost and time to build incremental liquefaction capacity. We expect to deploy our first Fast LNG unit in the first half of 2023. Our Shipping Assets Our shipping assets include: Floating Storage and Regasification Units ("FSRUs"), Floating Storage Units ("FSUs") and LNG carriers ("LNGCs"), which are either leased to customers under long-term or spot arrangements or operated by us. FSRUs provide offshore storage and regasification capabilities and are generally less costly and substantially faster to deploy compared to the construction and development of land-based LNG regasification and storage facilities. FSUs are floating storage assets, which often provide storage for LNG but are also capable of transporting LNG when required. LNG carriers are vessels that transport LNG and are compatible with many LNG loading and receiving terminals globally. Our shipping assets are included in our two operating segments, Ships and Terminals and Infrastructure. Vessels currently chartered to third parties are included in our Ships segment, and vessels we operate at our Facilities are included in our Terminals and Infrastructure segment. At the expiration of third party charters of vessels owned by Energos Infrastructure (Energos), a joint venture we formed in 2022 and describe in more detail below, we plan to charter these vessels for our own use through the periods described below in various capacities. We exclude these vessels from our Ships segment and include them in our Terminals and Infrastructure segment once we begin to use the vessels for our own operational purposes. We maintain flexibility to deploy vessels in our Terminals and Infrastructure segment as needed to operate our LNG supply chain and serve our downstream customers. On August 15, 2022, the Company and an affiliate of certain funds or investment vehicles managed by affiliates of Apollo Global Management, Inc., AP Neptune Holdings Ltd. ("Purchaser"), completed a sales and financing transaction regarding the substantial majority of our Shipping Assets. This sales and financing transaction was comprised of the formation of Energos and the sale or contribution of eleven vessels, including six FSRUs, three FSUs and two LNGCs (the Energos Formation Transaction). As a result of the Energos Formation Transaction, we own approximately a 20% equity interest in Energos, with the remaining interest owned by the Purchaser. In connection with the Energos Formation Transaction, we entered into long-term time charter agreements for periods of up to 20 years in respect of ten of the Energos vessels, the terms of which will commence upon the expiration of each vessels existing third-party charter. As a result of this arrangement, when existing third-party charters expire between April 2023 and August 2027, those vessels will then be chartered to us by Energos for 20-year terms expiring between December 2027 and August 2042. Set forth below are tables containing additional detail regarding each vessel in our operating segments: Ships Segment: ##TABLE_START Name Type Capacity (cubic meters of LNG) Owner Contract Type

Ticker: NFE, Sector: Utilities, Filed At: 2023-03-01T13:46:49-05:00

Location Igloo FSRU 170,000 Energos Lease The Netherlands Celsius LNGC / FSU 161,000 Energos Lease Various Penguin LNGC / FSU 161,000 Energos Lease Various Eskimo FSRU 161,000 Energos Lease Kingdom of Jordan Maria LNGC / FSU 146,000 Energos Lease Various Winter FSRU 138,000 Energos Lease Brazil Methane Princess LNGC / FSU 138,000 Energos Lease Various Mazo LNGC / FSU 137,000 60% NFE / 40% CPC Owned Various Spirit FSRU 129,000 NFE Owned Various Nusantara Regas Satu FSRU 125,000 Energos Lease Indonesia ##TABLE_ENDTerminals and Infrastructure Segment: ##TABLE_START Name Type Capacity (cubic meters of LNG) Owner Contract Type Location Orion sea LNGC / FSU 174,000 JP Morgan Lease Various Hoegh Gallant FSRU 170,000 Hoegh LNG Lease Jamaica Grand LNGC / FSU 146,000 Energos Lease Various Freeze FSRU 126,000 Energos Lease Various CNTIC Vpower Global LNGC / FSU 28,000 CNTIC Vpower Holdings Lease Various Coral Encanto LNGC / FSU 30,000 Anthony Veder Lease Various Avenir Accolade LNGC / FSU 7,500 Avenir Lease Various Coral Anthelia LNGC / FSU 6,500 Anthony Veder Lease Various ##TABLE_ENDOur Current Customers Our downstream customers are, and we expect future customers to be, a mix of power, transportation and industrial users of natural gas and LNG, as well as local power generation, distribution companies, including private and governmental owned or controlled. We seek to substantially reduce our customers fuel costs while providing them with a cleaner-burning, more environmentally-friendly fuel source. We also intend to sell power and steam directly to some of our customers. In addition, we provide development services to some customers for the conversion or development of natural gas-fired power generation in connection with long-term agreements to supply natural gas or LNG to the customer. We seek to enter into long-term take-or-pay contracts to deliver natural gas or LNG. Pricing for any particular customer depends on the size of the customer, purchased volume, the customers credit profile, the complexity of the delivery and the infrastructure required to deliver it. Our customer concentration has continually improved. Revenue from two customers constituted 42% of total revenue in 2022. For the years ended December 31, 2021 and 2020, revenue from three significant customers constituted 48% and 88% of the total revenue, respectively. We have several contracts with government-affiliated entities in the countries in which we operate. In Jamaica, we have gas sales agreements with JPS and SJPC, which have remaining terms of approximately 16 and 17 years, respectively, with mutual options to extend, subject to certain conditions. The Jamaica gas sales agreements represent approximately 50% of Jamaicas installed power capacity and sales of approximately 79,000 MMBtu from LNG per day at full commercial operations. The aggregate minimum quantities we are required to deliver, and our counterparties are required to purchase, under the Jamaica gas sales agreements initially, total approximately 56,000 MMBtu per day. In Puerto Rico, we have entered into a fuel sale and purchase agreement with PREPA, pursuant to which we expect PREPA to purchase 68,600 MMBtu from LNG per day in connection with the operation of both Units 5 and 6 of the PREPA San Juan Power Plant. In Mexico, we have entered into a gas sales agreement with CFEnergia for the supply of natural gas to CFE Plants. We expect to sell approximately 20,300 MMBtu from LNG per day under the gas sales agreement. In Nicaragua, we have entered into a 25-year power purchase agreement with Nicaraguas electricity distribution companies, some of which are wholly or partially owned or controlled by governmental entities. In Brazil, we have entered into various power purchase agreements with local distribution companies, some of which are wholly or partially owned or controlled by governmental entities. Competition In marketing LNG and natural gas, we compete for sales of LNG and natural gas primarily with LNG distribution companies who focus on sales of LNG without our integrated approach which includes development services and power. We also compete with a variety of natural gas marketers who may have affiliated distribution partners, including: major integrated marketers whose advantages include large amounts of capital and the ability to offer a wide range of services and market numerous products other than natural gas; producer marketers who sell natural gas they produce or which is produced by an affiliated company; small geographically focused marketers who focus their marketing on the geographic area in which their affiliated distributor operates; and aggregators who gather small volumes of natural gas from various sources, combine them and sell the larger volumes for more favorable prices and terms than would be possible selling the smaller volumes separately. Despite these competitors, we do not expect to experience significant competition for our LNG logistics services with respect to the Facilities to the extent we have entered into fixed GSAs or other long-term agreements we serve through the Facilities. If and when we have to replace our agreements with our counterparties, we may compete with other then-existing LNG logistics companies for these customers. In purchasing LNG, we compete for supplies of LNG with: large, multinational and national companies with longer operating histories, more development experience, greater name recognition, larger staffs and substantially greater financial, technical and marketing resources; oil and gas producers who sell or control LNG derived from their international oil and gas properties; and purchasers located in other countries where prevailing market prices can be substantially different from those in the United States. Government Regulation Our infrastructure business and operations are subject to extensive regulation under federal, state and local statutes, rules, regulations and laws, as well as foreign regulations and laws. These laws require, among other things, consultations with appropriate federal, state and other agencies and that we obtain, maintain and comply with applicable permits, approvals and other authorizations for the siting and conduct of our business. These regulatory requirements increase our costs of operations and construction, and failure to comply with such laws could result in consequences such as substantial penalties and/or the issuance of administrative orders to cease or restrict operations until we are in compliance. DOE Export The Department of Energy (DOE) issued orders authorizing us, through our subsidiary, American LNG Marketing LLC or its designee, to export up to a combined total of the equivalent of 60,000 mtpa (approximately 3.02 Bcf/yr) of domestically produced LNG by tanker from the Miami Facility to Free Trade Agreement (FTA) countries for a 20-year term and to non-FTA countries for a 20-year term under contracts with terms of two years or longer. The 20-year term of the authorizations commenced on February 5, 2016, the date of first export from the Miami Facility. The DOE has also authorized American LNG Marketing LLC or its designee to export LNG from the Miami Facility to FTA and non-FTA countries under short-term (less than two years) agreements or on a spot cargo basis. Any LNG exported under the short-term authorization would be counted toward the quantity authorized under the long-term authorizations. These authorizations from the DOE are only applicable to exports of LNG produced at our Miami Facility, and exports of LNG from a liquefaction facility other than the Miami Facility (such as the Pennsylvania Facility) to FTA and/or non-FTA countries will require us to obtain new authorizations from the DOE. The DOE issued an order authorizing us, through our subsidiary, NFEnerga LLC, to import LNG from various international sources by vessel at our San Juan Facility up to a total volume equivalent to 80 Bcf of natural gas over the two-year period beginning March 26, 2020. NFEnerga LLC must renew its authorization every two years. Imports of LNG are deemed to be consistent with the public interest under Section 3 of the Natural Gas Act (NGA) and applications for such imports must be granted without modification or delay. FERC Authorization The Federal Energy Regulatory Commission (FERC) regulates the siting, construction and operation of LNG terminals under NGA Section 3. In consultation with our outside counsel and, where appropriate, FERC staff, we have designed and constructed our U.S. facilities so that they do not meet the statutory definition of an LNG terminal as interpreted by FERC pursuant to its case law. On March 19, 2021, as upheld on rehearing on July 15, 2021, FERC determined that our San Juan Facility is subject to its jurisdiction and directed us to file an application for authorization to operate the San Juan Facility within 180 days of the order, which was September 15, 2021, but also found that allowing operation of the San Juan Facility to continue during the pendency of an application is in the public interest. The FERC orders were affirmed by the United States Court of the Appeals for the District of Columbia Circuit on June 14, 2022. In order to comply with the FERCs directive, on September 15, 2021, we filed an application for authorization to operate the San Juan Facility, which remains pending. Pipeline and Hazardous Materials Safety Administration Many LNG facilities are also subject to regulation by the Department of Transportation (DOT), through PHMSA; PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities, which PHMSA has defined to include certain LNG facilities that liquefy, store, transfer or vaporize natural gas transported by pipeline in interstate or foreign commerce. PHMSA has promulgated detailed, comprehensive regulations governing LNG facilities under its jurisdiction at Title 49, Part 193 of the United States Code of Federal Regulations. These regulations address LNG facility siting, design, construction, equipment, operations, maintenance, personnel qualifications and training, fire protection and security. Variances from these regulations may require obtaining a special permit from PHMSA, the issuance of which is subject to public notice and comment and consultation with other federal agencies, which could result in delays, perhaps substantial in length, to the construction of our facilities where such variances are needed; additionally, PHMSA may condition, revoke, suspend or modify the special permits it issues. In December 2019, PHMSA granted a special permit to one of our subsidiaries to ship LNG by rail, which would allow us to transport the LNG produced by the Pennsylvania Facility to a port for transloading onto marine vessels. On July 24, 2020, PHMSA issued a final rule authorizing the nationwide transportation of LNG by rail in DOT113C120W specification rail tank cars, subject to all applicable requirements and certain additional operational controls. The appeal period for the special permit has expired. However, in November 2021, PHMSA issued a proposed rule to rescind the final rule authorizing nationwide transportation. Pursuant to a September 2022 Congressional Interest Status Report, DOT projects that PHMSA would finalize this proposed rule on March 13, 2023. If promulgated along these lines, this rule would suspend authorization of LNG transportation by rail pending completion of a rulemaking evaluating the Hazardous Materials Regulations at 49 C.F.R. Parts 171-180 or by June 30, 2024, whichever is earlier. DOTs most recent statement contemplates issuing a Notice of Proposed Rulemaking for the rulemaking by March 20, 2023. We have the ability to transport LNG from our Pennsylvania Facility via truck, and this logistical solution is available to us should we be unable to transport by rail. Environmental Regulation Our infrastructure and operations are subject to various international, federal, state and local laws and regulations as well as foreign laws and regulations relating to the protection of the environment, natural resources and human health. These laws and regulations may require the installation of controls on emissions and structures to prevent or mitigate any potential harm to human health and the environment or require certain protocols to be in place for mitigating or responding to accidental or intentional incidents at certain facilities. These laws and regulations may also lead to substantial penalties for noncompliance and substantial liabilities for incidents arising out of the operation of our facilities. Many of these laws and regulations restrict or prohibit the types, quantities and concentration of substances that can be released into the environment and can lead to substantial civil and criminal fines and penalties for non-compliance. Other local laws and regulations, including local zoning laws, critical infrastructure regulations and fire protection codes, may also affect where and how we operate. The costs of compliance with these requirements are not expected to have a material adverse effect on our business, financial condition or results of operations. Environmental Regulation in Mexico Mexican law comprehensively regulates all aspects of the receipt, delivery, importation, exportation, storage commercialization, liquefaction, and regasification of LNG as well as the generation and transmission of electricity in Mexico. Various federal agencies in Mexico regulate these activities, among others, including the Department of Environment and Natural Resources, Department of Infrastructure, Communication and Transportation, Energy Regulatory Commission, and the Agency for Safety, Energy Environment, which issues permits for all activities associated with the use of Mexican hydrocarbon sector. State and local agencies also regulate these activities, issuing permits and authorizing the use of property for such purposes. In order to be able to obtain various permits for construction and operations under Mexican law, the project must first complete environmental and social impact assessments according to the requirements of Mexican law. Each such impact assessment is subject to further evaluation and appeal. Moreover, all hydrocarbon projects must include an environmental risk assessment, which derives from a thorough risk analysis before each different stage, in order to identify potential design and operational hazards. Mexican law allows the governmental entities and, in certain cases, individuals to pursue claims against violators of environmental laws or permits issued pursuant to such laws. In March 2021, an amendment to the Mexican Power Industry Law (Ley de la Industria Electrica) was published which would reduce the dispatch priority of privately-owned power plants compared to state-owned power plants in Mexico. The amendment is being challenged as unconstitutional, and a judge recently awarded a temporary injunction halting the implementation of the amendment. However, if the amendment is enforced against us, it could negatively affect our plants dispatch and our revenue and results of operations. This matter is currently under review by the Mexican Supreme Court. Environmental Regulation in Jamaica Our operations in Jamaica are governed by various environmental laws and regulations. These laws and regulations are largely implemented through the National Environment and Planning Agency and cover discharges of pollutants, regulation of air emissions, discharges and treatment of wastewater, storage of fuels, and responses to industrial emergencies involving hazardous materials. The level of environmental regulation in Jamaica has increased in recent years, and the enforcement of environmental laws is becoming more stringent. Compliance has not had a material adverse effect on our business, operations, or financial condition, but we cannot assure you that this will be the case in the future. Jamaica is also in the process of developing a law to govern the receipt, storage, processing and distribution of natural gas, as well as requirements for the licensing, construction, and operation of natural gas facilities and transportation. Environmental Regulation in Nicaragua The regulation of activities with the potential to impact the environment in Nicaragua are largely regulated by the Natural Resource and Environment Ministry. Nicaragua regulates many areas of environmental protection. In order to obtain various permits for operations, a project must complete environmental and social impact analyses according to Nicaraguan law. While Nicaragua does not currently have any legislation specifically addressing the receipt, handling, and distribution of natural gas, such laws may be passed in the future. Environmental Regulation in Ireland The operation of the facilities will be regulated via additional licenses and consents including from the Environmental Protection Agency (EPA); the Commission for Regulation of Utilities (CRU); the Health and Safety Authority (HSA); and the Local Planning Authority (Kerry Co. Council (KCC)). Additionally, the Shannon Foynes Port Company (SFPC) has statutory jurisdiction over marine activities. The LNG Terminal and Power Plant will also have to operate within the provisions of a number of codes, such as the EirGrid Transmission Network Grid Code, Single Electricity Market

Trading and Settlement Code and GNI Code of Operations. We are in the process of applying for all these necessary permits, licenses and consents to build and complete the Ireland Facility. The issuance of many of these permits may be subject to administrative or judicial challenges, including by non-governmental groups that act on behalf of citizens. We intend to begin construction of the Ireland Facility after we have obtained planning permission and secured contracts with downstream customers for volumes that are sufficient to support the development of the Ireland Facility. Environmental Regulation in Brazil Our operations in Brazil are governed by various environmental laws and regulations. These laws and regulations cover social and environmental impacts, air emissions, discharges and treatment of residues, and emergency response, among others. According to Brazilian environmental legislation, the environmental licensing for energy generation activities must follow three stages: a Preliminary License that authorizes the design of the project and the location of the enterprise, an Installation License that authorizes the start of the implementation activities and, an Operating License, which authorizes the actual start of the activity. At each stage, specific environmental plans and studies are required to assess and mitigate the impacts on the environment. In addition, some other authorizations may be required by environmental authorities on a local (municipal), state and federal level, including permits to suppress vegetation, authorization for fauna management, permission to address and/or otherwise mitigate impacts on affected communities, and others. U.S. and International Maritime Regulations of LNG Vessels The International Maritime Organization (IMO) is the United Nations agency that provides international regulations governing shipping and international maritime trade. The requirements contained in the International Safety Management Code for the Safe Operation of Ships and for Pollution Prevention (the ISM Code) promulgated by the IMO govern the shipping of our LNG cargos and the operations of any vessels we use in our operations. Among other requirements, the ISM Code requires the party with operational control of a vessel to develop an extensive safety management system that includes, among other things, the adoption of a policy for safety and environmental protection setting forth instructions and procedures for operating its vessels safely and describing procedures for responding to emergencies. Vessels that transport gas, including LNGCs, are also subject to regulation under various international programs such as the International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (the IGC Code) published by the IMO. The IGC Code provides a standard for the safe carriage of LNG and certain other liquid gases by prescribing the design and construction standards of vessels involved in such carriage, and includes specific air emissions limits, including on sulfur oxide and nitrogen oxide emissions from ship exhausts. We contract with leading vessel providers in the LNG industry and look to them to ensure that each of our chartered vessels is in compliance with applicable international and in-country requirements. Nevertheless, the IMO continues to review and introduce new regulations and it is impossible to predict what additional regulations, if any, may be passed by the IMO and what effect, if any, such regulation may have on our operations.] Suppliers and Working Capital We expect to continue to supply our downstream customers with LNG and natural gas sourced from a combination of long-term, LNG contracts with attractive terms, purchases on the open market, from our Miami Facility, and when completed, our Fast LNG solutions and Pennsylvania Facility. Seasonality Our operations can be affected by seasonal weather, which can temporarily affect our revenues, the delivery of LNG and the construction of our Facilities. For example, activity in the Caribbean is often lower during the North Atlantic hurricane season of June through November, and following a hurricane, activity may decrease further as there may be business interruptions as a result of damage or destruction to our Facilities or the countries in which we operate. The Brazilian electric integrated system is largely dependent on hydro-generated power, which is affected during dry seasons, requiring other sources of power, such as natural gas-fired thermal power station, to dispatch more or less based on the amount of the rainfall during any period. Due to these seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of the results that may be realized on an annual basis. Severe weather in the countries where our Facilities are located may delay completion of our Facilities under development and related infrastructure, adversely affect our operations of our Facilities and affect the markets in which we operate. We are also particularly exposed to the risks posed by hurricanes, tropical storms and their collateral effects, in particular with respect to fleet operations, floating offshore liquefaction units and other infrastructure we may develop in connection with our Fast LNG technology. Our Insurance Coverage We maintain customary insurance coverage for our business and operations. Our domestic insurance related to property, equipment, automobile, general liability and workers compensation is provided through policies customary for the business and exposures presented, subject to deductibles typical in the industry. Internationally, we also maintain insurance related to property, equipment, automobile, marine, pollution liability, general liability and the portion of workers compensation not covered under a governmental program. We maintain property insurance, including named windstorm and flood, related to the operation of the Miami Facility, San Juan Facility, the La Paz Facility, and the Jamaica Facilities and builders risk insurance at our Facilities under development. Human Capital We had 577 full-time employees as of December 31, 2022. We depend upon our skilled workforce to manage, operate and plan for our business. Recruitment and retention of talent across our Company enables growth and innovation across a multitude of corporate initiatives, and this is one of our top priorities. Our Human Resources team oversees human capital management, including talent attraction and retention, compensation and bonuses, employee relations, employee engagement and training and development in the various countries in which we operate. Diversity and Inclusion Our employees are critical to the success of our business. We value the diversity of our workplace and are committed to maintaining culture where our employees feel valued, welcomed and can thrive. We are subject to various federal, state and local laws related to labor and employment, including matters related to workplace discrimination, harassment and unlawful retaliation in the jurisdictions in which we operate. We have developed and published our Code of Business Conduct, which sets out a guideline in connection with these matters and reflects our high expectations for an ethical workplace where employees are treated with dignity and respect. Because labor and employment laws and regulations can differ among the jurisdictions in which we operate, our Code of Business Conduct operates as a guideline for practices, but is not binding or required. We are advancing our commitments to diversity and inclusion through the following actions, among others: collecting and analyzing diversity data; conducting harassment trainings; and expanding employee benefits to include additional health programs such as mental health support and medical concierge services. Employee Health, Safety and Wellness We are subject to various health, safety, and environmental laws and regulations in the jurisdictions in which we operate. We have developed and published a Health, Safety, Security and Environment (HSSE) Strategic Framework, which sets out a guideline in connection with risk management, education/training, emergency response, incident management, performance measurement and other key programmatic drivers. Because health, safety, and environmental laws and regulations can differ among the jurisdictions in which we operate, our Health, Safety, Security and Environment (HSSE) Strategic Framework operates as a guideline for practices, but is not binding or required. We also have developed and published a contractor safety management handbook for our contractors. For the year ended December 31, 2022, we achieved zero employee recordable incidents, lost time incidents or fatalities across our operating sites. Property We lease space for our offices in New York, New York, Houston, Texas, Rio de Janeiro, Brazil, and in other regions in which we operate. We own the properties on which our Pennsylvania Facility will be located. Additionally, the properties on which our Facilities, the CHP Plant and Miami Facility are located are generally subject to long-term leases and rights-of-way. Our leased properties are subject to various lease terms and expirations. Sustainability Since our founding in 2014, sustainability has been at the core of our mission and vision. We believe that a sustainable future built on positive energy is the way forward. To advance both our business model and the interests of our stakeholders including our people, shareholders and investors, partners, the communities we serve, and the wider publicwe have established four key sustainability goals: (i) protect and preserve the environment, (ii) empower people worldwide, (iii) invest in communities, and (iv) become a leading provider of very-low-carbon energy. Our sustainability initiatives and investments under each of these goals are highlighted below. Protect and Preserve the Environment We are committed to our goal to protect and preserve the environment, and we progress this goal by providing cleaner energy solutions around the world. With our projects, we strive to reduce carbon emissions and increase energy efficiency. By helping our customers convert from traditional fuels such as oil or coal to liquefied natural gas (LNG) as their energy source, we seek to reduce air-polluting emissions of nitrogen oxide (NOx), carbon dioxide (CO2), sulfur oxide (SOx), and fine particulate matter, among others. Moreover, we believe that the use of LNG as a complement to renewable power options is helping the transition to a sustainably-sourced energy future . Empower People Worldwide We are committed to our goal to provide access to affordable, reliable, cleaner energy. To that end, we help our customers customize and implement LNG energy solutions designed to lower their energy costs, reduce their environmental footprint, and improve their energy efficiency, either by converting their existing power generation to LNG or by building brand-new gas-fired facilities. In addition, we seek to provide a reliable supply of LNG to our customers, wherever located, through our established, integrated LNG logistics chain. Invest in Communities We are committed to our goal to improve lives and support people, especially in the communities where we operate. For example, through our New Fortress Energy Foundation, we seek to strengthen our communities by (i) investing in education to help support the next generation of leaders; (ii) providing industry training programs to help create and sustain a well-equipped workforce; and (iii) giving financially to community causes that enhance quality of life, including reducing poverty, hunger, and inequities. In 2021, we provided more than 75 higher education scholarships, financial aid to more than 1,000 students, backpacks and supplies to 1,600 students, and supported academic opportunities of more than 5,000 students in the fields of science, technology, engineering and mathematics (STEM). We donated more than 100,000 trees in Jamaica and Africa, supporting more than 500 local farmers. For the holiday season in 2021, we provided approximately 3,700 children with new clothes and toys. Toward a Very-Low-Carbon Future As we work to reduce greenhouse gas (GHG) emissions for our customers around the world, our goals are to reach net zero carbon emissions by 2030 and be one of the worlds leading providers of very-low-carbon energy. We believe that natural gas remains a cost-effective and environmentally-friendly complement for intermittent renewable energy, aiding the growth of these technologies. Over time, we believe that hydrogen will play an increasingly significant role as a very-low-carbon fuel to support renewables and displace fossil fuels across power, transportation and industrial markets. To that end, we formed a division, which we call Zero, to evaluate promising technologies and pursue initiatives that will position us to capitalize on this emerging industry. Available Information We are required to file or furnish any annual, quarterly and current reports, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934, as amended (the Exchange Act). The SEC maintains an internet website that contains reports, proxy and information statements and other information regarding issuers, including us, that file electronically with the SEC. The public can obtain any documents that we file with the SEC, including this Annual Report, at www.sec.gov . We also make available free of charge through our website, www.newfortressenergy.com, our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8- K, and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Information on our website or any other website is not incorporated by reference into, and does not constitute a part of, this Annual Report. Additionally, we have made our annual Sustainability Report and environmental, social and governance (ESG) related documents available on our website, www.newfortressenergy.com, to provide more detailed information regarding our human capital programs and initiatives as well as our efforts to manage ESG issues. Item 1A. Risk Factors An investment in our Class A common stock involves a high degree of risk. You should carefully consider the risks described below. If any of the following risks were to occur, the value of our Class A common stock could be materially adversely affected or our business, financial condition and results of operations could be materially adversely affected and thus indirectly cause the value of our Class A common stock to decline. Additional risks not presently known to us or that we currently deem immaterial could also materially affect our business and the value of our Class A common stock. As a result of any of these risks, known or unknown, you may lose all or part of your investment in our Class A common stock. The risks discussed below also include forward-looking statements, and actual results may differ substantially from those discussed in these forward-looking statements. See Cautionary Statement on Forward-Looking Statements.. Unless the context otherwise requires, references to Company, NFE, we, our, us or like terms refer to (i) prior to the completion of Mergers, New Fortress Energy Inc. and its subsidiaries, excluding Hygo Energy Transition Ltd. (Hygo) and its subsidiaries and Golar LNG Partners LP (GMLP) and its subsidiaries, and (ii) after completion of the Mergers, New Fortress Energy Inc. and its subsidiaries, including Hygo and its subsidiaries and GMLP and its subsidiaries. Summary Risk Factors Some of the factors that could materially and adversely affect our business, financial condition, results of operations or prospects include the following: Risks Related to Our Business We have a limited operating history, which may not be sufficient to evaluate our business and prospects; Our ability to implement our business strategy may be materially and adversely affected by many known and unknown factors; We are subject to various construction risks; Operation of our infrastructure, facilities and vessels involves significant risks; We depend on third-party contractors, operators and suppliers; Failure of LNG to be a competitive source of energy in the markets in which we operate, and seek to operate, could adversely affect our expansion strategy; We operate in a highly regulated environment and our operations could be adversely affected by actions by governmental entities or changes to regulations and legislation; Failure to obtain and maintain permits, approvals and authorizations from governmental and regulatory agencies and third parties on favorable terms could impede operations and construction; When we invest significant capital to develop a project, we are subject to the risk that the project is not successfully developed and that our customers do not fulfill their payment obligations to us following our capital investment in a project; Failure to maintain sufficient working capital could limit our growth and harm our business, financial condition and results of operations; Our ability to generate revenues is substantially dependent on our current and future long-term agreements and the performance by customers under such agreements; Our current lack of asset and geographic diversification could have an adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects; Because we are currently dependent upon a limited number of customers, the loss of a significant customer could adversely affect our operating results; We may not be able to convert our anticipated customer pipeline into binding long-term contracts, and if we fail to convert potential sales into actual sales, we will not generate the revenues and profits we anticipate; Our contracts with our customers are subject to termination under certain circumstances; Competition in the LNG industry is intense, and some of our competitors have greater financial, technological and other resources than we currently possess; Cyclical or other changes in the demand for and price of LNG and natural gas may adversely affect our business and the performance of our customers; Our risk management strategies cannot eliminate all LNG price and supply risks. In addition, any non-compliance with our risk management strategies could result in significant financial losses; We are dependent on third-party LNG suppliers and may not be able to purchase or receive physical delivery of LNG or natural gas in sufficient quantities and/or at economically attractive prices to satisfy our delivery obligations under the GSAs, PPAs and SSAs; We seek to develop innovative and new technologies as part of our strategy that are not yet proven and may not realize the time and cost savings we expect to achieve; Our Fast LNG technology is not yet proven and we may not be able to implement it as planned or at all; We have incurred, and may in the future incur, a significant amount of debt; Our business is dependent upon obtaining substantial additional funding from various sources, which may not be available or may only be available on unfavorable terms; Weather events or other natural or manmade disasters or phenomena, some of which may be adversely impacted by global climate change, could have a material adverse effect on our operations and projects, as well as on the economies in the markets in which we operate or plan to operate; We may experience increased labor costs and regulation, and the unavailability of skilled workers or our failure to attract and retain qualified personnel, as well as our ability to comply with such labor laws, could adversely affect; Risks Related to the Jurisdictions in Which We Operate We are subject to the economic, political, social and other conditions in the jurisdictions in which we operate; Our financial condition and operating results may be adversely affected by foreign exchange fluctuations; Risks Related to Ownership of Our Class A Common Stock A small number of our original investors have the ability to direct the voting of a majority of our stock, and their interests may conflict with those of our other stockholders; The declaration and payment of dividends to holders of our Class A common stock is at the discretion of our board of directors and there can be no assurance that we will continue to pay dividends in amounts or on a basis consistent with prior distributions to our investors, if at all; General Risks We are a holding company and our operational and consolidated financial results are dependent on the results of our subsidiaries, affiliates, joint ventures and special purpose entities in which we invest; We may engage in mergers, sales and acquisitions, reorganizations or similar transactions related to our businesses or assets in the future and we may fail to successfully complete such transaction or to realize the expected value; We are unable to predict the extent to which the global COVID-19 pandemic will negatively affect our operations, financial performance, nor our ability to achieve our strategic objectives. We are also unable to predict how this global pandemic may affect our customers and suppliers; and A change in tax laws in any country in which we operate could adversely affect us. Risks Related to Our Business We have a limited operating history, which may not be sufficient to evaluate our business and prospects. We have a limited operating history and track record. As a result, our prior operating history and historical financial statements may not be a reliable basis for evaluating our business prospects or the value of our Class A common stock. We commenced operations on February 25, 2014, and we had net losses of approximately $78.2 million in 2018, $204.3 million in 2019, and $264.0 million in 2020. We recognized income of $92.7 million in 2021 and $184.8 million in 2022. Our limited operating history also means that we continue to develop and implement our strategies, policies and procedures, including those related to project development planning, operational supply chain planning, data privacy and other matters. We cannot give you any assurance that our strategy will be successful or that we will be able to implement our strategy on a timely basis, if at all, or achieve our internal model or that our assumptions will be accurate. Our ability to implement our business strategy may be materially and adversely affected by many known and unknown factors. Our business strategy relies on a variety of factors, including our ability to successfully market LNG, natural gas, steam, and power to end-users, develop and maintain cost-effective logistics in our supply chain and construct, develop and operate energy-related infrastructure in the countries where we operate, and expand our projects and operations to other countries where we do not currently operate, among others. These assumptions are subject to significant economic, competitive, regulatory and operational uncertainties, contingencies and risks, many of which are beyond our control, including, among others: inability to achieve our target costs for the purchase, liquefaction and export of natural gas and/or LNG and our target pricing for long-term contracts; failure to develop strategic relationships; failure to obtain required governmental and regulatory approvals for the construction and operation of these projects and other relevant approvals; unfavorable laws and regulations, changes in laws or unfavorable interpretation or application of laws and regulations; and uncertainty regarding the timing, pace and extent of an economic recovery in the United States, the other jurisdictions in which we operate and elsewhere, which in turn will likely affect demand for crude oil and natural gas. Furthermore, as part of our business strategy, we target customers who have not been traditional purchasers of natural gas, including customers in developing countries, and these customers may have greater credit risk than typical natural gas purchasers. Therefore, we may be exposed to greater customer credit risk than other companies in the industry. Our credit procedures and policies may be inadequate to sufficiently eliminate risks of nonpayment and nonperformance. Our strategy may evolve over time. Our future ability to execute our business strategy is uncertain, and it can be expected that one or more of our assumptions will prove to be incorrect and that we will face unanticipated events and circumstances that may adversely affect our ability to execute our business strategy and adversely affect our business, financial condition and results of operations. We are subject to various construction risks. We are involved in the development of complex small, medium and large-scale engineering and construction projects, including our facilities, liquefaction facilities, power plants, and related infrastructure, which are often developed in multiple stages involving commercial and governmental negotiations, site planning, due diligence, permit requests, environmental impact studies, permit applications and review, marine logistics planning and transportation and end-user delivery logistics. In addition to our facilities, these infrastructure projects can include the development and construction of facilities as part of our customer contracts. Projects of this type are subject to a number of risks including, among others: engineering, environmental or geological problems; shortages or delays in the delivery of equipment and supplies; government or regulatory approvals, permits or other authorizations; failure to meet technical specifications or adjustments being required based on testing or commissioning; construction accidents that could result in personal injury or loss of life; lack of adequate and qualified personnel to execute the project; weather interference; and potential labor shortages, work stoppages or labor union disputes. Furthermore, because of the nature of our infrastructure, we are dependent on interconnection with transmission systems and other infrastructure projects of third parties, including our customers, and/or governmental entities. Such third-party projects can be greenfield or brownfield projects, including modifications to existing infrastructure or increases in capacity to existing facilities, among others, and are subject to various construction risks. Delays from such third parties or governmental entities could prevent connection to our projects and generate delays in our ability to develop our own projects. In addition, a primary focus of our business is the development of projects in foreign jurisdictions, including in locations where we have no prior development experience, and we expect to continue expanding into new jurisdictions in the future. These risks can be increased in jurisdictions where legal processes, language differences, cultural expectations, currency exchange requirements, political relations with the U.S. government, changes in the political views and structure, government representatives, new regulations, regulatory reviews, employment laws and diligence requirements can make it more difficult, time-consuming and expensive to develop a project. See Risks Related to the Jurisdictions in Which We OperateWe are subject to the economic, political, social and other conditions in the jurisdictions in which we operate . The occurrence of any one of these factors, whatever the cause, could result in unforeseen delays or cost overruns to our projects. Delays in the development beyond our estimated timelines, or amendments or change orders to our construction contracts, could result in increases to our development costs beyond our original estimates, which could require us to obtain additional financing or funding and could make the project less profitable than originally estimated or possibly not profitable at all. Further, any such delays could cause a delay in our anticipated receipt of revenues, a loss of one or more customers in the event of significant delays, and our inability to meet milestones or conditions precedents in our customer contracts, which could lead to delay penalties and potentially a termination of agreements with our customers. We have experienced time delays and cost overruns in the construction and development of our projects as a result of the occurrence of various of the above factors, and no assurance can be given that we will not continue to experience in the future similar events, any of which could have a material adverse effect on our business, operating results, cash flows and liquidity. Operation of our infrastructure, facilities and vessels involves significant risks. Our existing infrastructure, facilities and vessels and expected future operations and businesses face operational risks, including, but not limited to, the following: performing below expected levels of efficiency or capacity or required changes to specifications for continued operations; breakdowns or failures of equipment or shortages or delays in the delivery of supplies; operational errors by trucks, including trucking accidents while transporting natural gas, LNG or any other chemical or hazardous substance; risks related to operators and service providers of tankers or tugs used in our operations; operational errors by us or any contracted facility, port or other operator of related infrastructure; failure to maintain the required government or regulatory approvals, permits or other authorizations; accidents, fires, explosions or other events or catastrophes; lack of adequate and qualified personnel; potential labor shortages, work stoppages or labor union disputes; weather-related or natural disaster interruptions of operations; pollution, release of or exposure to toxic substances or environmental contamination affecting operation; inability, or failure, of any counterparty to any facility-related agreements to perform their contractual obligations; decreased demand by our customers, including as a result of the COVID-19 pandemic; and planned and unplanned power outages or failures to supply due to scheduled or unscheduled maintenance. In particular, we are subject to risks related to the operation of power plants, liquefaction facilities, marine and other LNG operations with respect to our facilities, floating storage regasification units ("FSRU") and LNG carriers, which operations are complex and technically challenging and subject to mechanical risks and problems. In particular, marine LNG operations are subject to a variety of risks, including, among others, marine disasters, piracy, bad weather, mechanical failures, environmental accidents, epidemics, grounding, fire, explosions and collisions, human error, and war and terrorism. An accident involving our cargos or any of our chartered vessels could result in death or injury to persons, loss of property or environmental damage; delays in the delivery of cargo; loss of revenues; termination of charter contracts; governmental fines, penalties or restrictions on conducting business; higher insurance rates; and damage to our reputation and customer relationships generally. Any of these circumstances or events could increase our costs or lower our revenues. If our chartered vessels suffer damage as a result of such an incident, they may need to be repaired. Repairs and maintenance costs for existing vessels are difficult to predict and may be substantially higher than for vessels we have operated since they were built and result in higher than anticipated operating expenses or require additional capital expenditures. The loss of earnings while these vessels are being repaired would decrease our results of operations. If a vessel we charter were involved in an accident with the potential risk of environmental impacts or contamination, the resulting media coverage could have a material adverse effect on our reputation, our business, our results of operations and cash flows and weaken our financial condition. Our offshore operating expenses depend on a variety of factors including crew costs, provisions, deck and engine stores and spares, lubricating oil, insurance, maintenance and repairs and shipyard costs, many of which are beyond its control, such as the overall economic impacts caused by the global COVID-19 outbreak. Other factors, such as increased cost of qualified and experienced seafaring crew and changes in regulatory requirements, could also increase operating expenditures. Future increases to operational costs are likely to occur. If costs rise, they could materially and adversely affect our results of operations. In addition, operational problems may lead to loss of revenue or higher than anticipated operating expenses or require additional capital expenditures. Any of these results could harm our business, financial condition and results of operations. We cannot assure you that future occurrences of any of the events listed above or any other events of a similar or dissimilar nature would not significantly decrease or eliminate the revenues from, or significantly increase the costs of operating, our facilities or assets. We depend on third-party contractors, operators and suppliers. We rely on third-party contractors, equipment manufacturers, suppliers and operators for the development, construction and operation of our projects and assets. We have not yet entered into binding contracts for the construction, development and operation of all of our facilities and assets, and we cannot assure you that we will be able to enter into the contracts required on commercially favorable terms, if at all, which could expose us to fluctuations in pricing and potential changes to our planned schedule. If we are unable to enter into favorable contracts, we may not be able to construct and operate these assets as expected, or at all. Furthermore, these agreements are the result of arms-length negotiations and subject to change. There can be no assurance that contractors and suppliers will perform their obligations successfully under their agreements with us. If any contractor is unable or unwilling to perform according to the negotiated terms and timetable of its respective agreement for any reason or terminates its agreement for any reason, we would be required to engage a substitute contractor, which could be particularly difficult in certain of the markets in which we plan to operate. For example, each of our vessels is operated and maintained by GLNG or its affiliates pursuant to ship management agreements. Any failure by GLNG or its affiliates in the operation of our vessels could have an adverse effect on our maritime operations and could result in our failure to deliver LNG to our customers as required under our customer agreements. Although some agreements may provide for liquidated damages if the contractor or supplier fails to perform in the manner required with respect to its obligations, the events that trigger such liquidated damages may delay or impair the completion or operation of the facility, and any liquidated damages that we receive may be delayed or insufficient to cover the damages that we suffer as a result of any such delay or impairment, including, among others, any covenants or obligations by us to pay liquidated damages or penalties under our agreements with our customers, development services, the supply of natural gas, LNG or steam and the supply of power, as well as increased expenses or reduced revenue. Such liquidated damages may also be subject to caps on liability, and we may not have full protection to seek payment from our contractors to compensate us for such payments and other consequences. We may hire contractors to perform work in jurisdictions where they do not have previous experience, or contractors we have not previously hired to perform work in jurisdictions we are beginning to develop, which may lead to such contractors being unable to perform according to its respective agreement. Furthermore, we may have disagreements with our contractors about different elements of the construction process, which could lead to the assertion of rights and remedies under their contracts and increase the cost of the applicable facility or result in a contractors unwillingness to perform further work. If we are unable to construct and commission our facilities and assets as expected, or, when and if constructed, they do not accomplish our goals, or if we experience delays or cost overruns in construction, our business, operating results, cash flows and liquidity could be materially and adversely affected. Failure of LNG to be a competitive source of energy in the markets in which we operate, and seek to operate, could adversely affect our expansion strategy. Our operations are, and will be, dependent upon LNG being a competitive source of energy in the markets in which we operate. In the United States, due mainly to a historic abundant supply of natural gas and discoveries of substantial quantities of unconventional or shale natural gas, imported LNG has not developed into a significant energy source. The success of the domestic liquefaction component of our business plan is dependent, in part, on the extent to which natural gas can, for significant periods and in significant volumes, be produced in the United States at a lower cost than the cost to produce some domestic supplies of other alternative energy sources, and that it can be transported at reasonable rates through appropriately scaled infrastructure. Since August 2021, LNG prices have increased materially, and global events, such as the COVID-19 pandemic, Russia's invasion of Ukraine and global inflationary pressures, have generated further energy pricing volatility, which can have an adverse effect on market pricing of LNG and global demand for our products, as well as our ability to remain competitive in the markets in which we operate. Potential expansion in the Caribbean, Latin America and other parts of world where we may operate is primarily dependent upon LNG being a competitive source of energy in those geographical locations. For example, in the Caribbean, due mainly to a lack of regasification infrastructure and an underdeveloped international market for natural gas, natural gas has not yet developed into a significant energy source. In Brazil, hydroelectric power generation is the predominant source of electricity and LNG is one of several other energy sources used to supplement hydroelectric generation. The success of our operations is dependent, in part, on the extent to which LNG can, for significant periods and in significant volumes, be produced internationally and delivered to our customers at a lower cost than the cost to deliver other alternative energy sources. Political instability in foreign countries that export LNG, or strained relations between such countries and countries in the Caribbean and Latin America, may also impede the willingness or ability of LNG suppliers and merchants in such countries to export LNG to the Caribbean, Latin America and other countries where we operate or seek to operate. Furthermore, some foreign suppliers of LNG may have economic or other reasons to direct their LNG to other markets or from or to our competitors LNG facilities. Natural gas also competes with other sources of energy, including coal, oil, nuclear, hydroelectric, wind and solar energy, which may become available at a lower cost in certain markets. As a result of these and other factors, natural gas may not be a competitive source of energy in the markets we intend to serve or elsewhere. The failure of natural gas to be a competitive supply alternative to oil and other alternative energy sources could adversely affect our ability to deliver LNG or natural gas to our customers on a commercial basis, which could have a material adverse effect on our business, ability to realize benefits from future projects, results of operations, financial condition, liquidity and prospects. We operate in a highly regulated environment and our operations could be adversely affected by actions by governmental entities or changes to regulations and legislation Our business is highly regulated and subject to numerous governmental laws, rules, regulations and requires permits, authorizations and various governmental and agency approvals, in the various jurisdictions in which we operate, that impose various restrictions and obligations that may have material effects on our business and results of operations. Each of the applicable regulatory requirements and limitations is subject to change, either through new regulations enacted on the federal, state or local level, or by new or modified regulations that may be implemented under existing law. The nature and extent of any changes in these laws, rules, regulations and permits may be unpredictable, have retroactive effects, and may have material effects on our business. Future legislation and regulations or changes in existing legislation and regulations, or interpretations thereof, such as those relating to power, natural gas or LNG operations, including exploration, development and production activities, liquefaction, regasification or transportation of our products, could cause additional expenditures, restrictions and delays in connection with our operations as well as other future projects, the extent of which cannot be predicted and which may require us to limit substantially, delay or cease operations in some circumstances. In addition, these rules and regulations are assessed, managed, administered and enforced by various governmental agencies and bodies, whose actions and decisions could adversely affect our business or operations. In the United States and Puerto Rico, approvals of the Department of Energy ("DOE") under Section 3 of the NGA, as well as several other material governmental and regulatory permits, approvals and authorizations, including under the CAA and the CWA and their state analogues, may be required in order to construct and operate an LNG facility and export LNG. Permits, approvals and authorizations obtained from the DOE and other federal and state regulatory agencies also contain ongoing conditions, and additional requirements may be imposed. Certain federal permitting processes may trigger the requirements of the National Environmental Policy Act (NEPA), which requires federal agencies to evaluate major agency actions that have the potential to significantly impact the environment. Compliance with NEPA may extend the time and/or increase the costs for obtaining necessary governmental approvals associated with our operations and create independent risk of legal challenges to the adequacy of the NEPA analysis, which could result in delays that may adversely affect our business, contracts, financial condition, operating results, cash flow, liquidity and profitability. On July 15, 2020, the White House Council on Environmental Quality issued a final rule revising its NEPA regulations. These regulations have taken legal effect, and although they have been challenged in court, they have not been stayed. The Council on Environmental Quality has announced that it is engaged in an ongoing and comprehensive review of the revised regulations and is assessing whether and how the Council may ultimately undertake a new rulemaking to revise the regulations. The impacts of any such future revisions that may be adopted are uncertain and indeterminable for the foreseeable future. On June 18, 2020, we received an order from FERC, which asked us to explain why our San Juan Facility is not subject to FERCs jurisdiction under section 3 of the NGA. On March 19, 2021, as upheld on rehearing on July 15, 2021, FERC determined that our San Juan Facility is subject to its jurisdiction and directed us to file an application for authorization to operate the San Juan Facility within 180 days of the order, which was September 15, 2021, but also found that allowing operation of the San Juan Facility to continue during the pendency of an application is in the public interest. The FERC orders were affirmed by the United States Court of the Appeals for the District of Columbia Circuit on June 14, 2022. In order to comply with the FERCs directive, on September 15, 2021, we filed an application for authorization to operate the San Juan Facility, which remains pending. We may not comply with each of these requirements in the future, or at all times, including any changes to such laws and regulations or their interpretation. The failure to satisfy any applicable legal requirements may result in the suspension of our operations, the imposition of fines and/or remedial measures, suspension or termination of permits or other authorization, as well as potential administrative, civil and criminal penalties, which may significantly increase compliance costs and the need for additional capital expenditures. Failure to obtain and maintain permits, approvals and authorizations from governmental and regulatory agencies and third parties on favorable terms could impede operations and construction. The design, construction and operation of our infrastructure, facilities and businesses, including our FSRUs, FLNG units and LNG carriers, the import and export of LNG, exploration and development activities, and the transportation of natural gas, among others, are highly regulated activities at the national, state and local levels and are subject to various approvals and permits. The process to obtain the permits, approvals and authorizations we need to conduct our business, and the interpretations of those rules, is complex, time-consuming, challenging and varies in each jurisdiction in which we operate. We may be unable to obtain such approvals on terms that are satisfactory for our operations and on a timeline that meets our commercial obligations. Many of these permits, approvals and authorizations require public notice and comment before they can be issued, which can lead to delays to respond to such comments, and even potentially to revise the permit application. We may also be (and have been in select circumstances) subject to local opposition, including citizens groups or non-governmental organizations such as environmental groups, which may create delays and challenges in our permitting process and may attract negative publicity, which may create an adverse impact on our reputation. In addition, such rules change frequently and are often subject to discretionary interpretations, including administrative and judicial challenges by regulators, all of which may make compliance more difficult and may increase the length of time it takes to receive regulatory approval for our operations, particularly in countries where we operate, such as Mexico and Brazil. For example, in Mexico, we have obtained substantially all permits but are awaiting regasification and transmission permits for our power plant and permits necessary to operate our terminal. In connection with our application to the U.S. Maritime Administration ("MARAD") related to our FLNG project off the coast of Louisiana, MARAD announced it had initially paused the statutory 356-day application review timeline on August 16, 2022 pending receipt of additional information, and restarted the timeline on October 28, 2022. MARAD issued a second stop notice on November 23, 2022 and on December 22, 2022, MARAD issued a third data request for supplemental information. Following review of NFEs response to the December 2022 data requests, MARAD extended the stop clock on February 21, 2023 pending clarification of responses and receipt of additional information. No assurance can be given that we will be able to obtain approval of this application and receive the required permits, approvals and authorizations from governmental and regulatory agencies related to our project on a timely basis or at all. We intend to apply for updated permits for the Pennsylvania Facility with the aim of obtaining these permits to coincide with the commencement of construction activities. We cannot assure if or when we will receive these permits, which are needed prior to commencing certain construction activities related to the facility. Any administrative and judicial challenges can delay and protract the process for obtaining and implementing permits and can also add significant costs and uncertainty. We cannot control the outcome of any review or approval process, including whether or when any such permits and authorizations will be obtained, the terms of their issuance, or possible appeals or other potential interventions by third parties that could interfere with our ability to obtain and maintain such permits and authorizations or the terms thereof. Furthermore, we are developing new technologies and operate in jurisdictions that may lack mature legal and regulatory systems and may experience legal instability, which may be subject to regulatory and legal challenges, instability or clarity of application of laws, rules and regulations to our business and new technology, which can result in difficulties and instability in obtaining or securing required permits or authorizations. There is no assurance that we will obtain and maintain these permits and authorizations on favorable terms, or that we will be able to obtain them on a timely basis, and we may not be able to complete our projects, start or continue our operations, recover our investment in our projects and may be subject to financial penalties or termination under our customer and other agreements, which could have a material adverse effect on our business, financial condition, operating results, liquidity and prospects. When we invest significant capital to develop a project, we are subject to the risk that the project is not successfully developed and that our customers do not fulfill their payment obligations to us following our capital investment in a project . A key part of our business strategy is to attract new customers by agreeing to finance and develop new facilities, power plants, liquefaction facilities and related infrastructure in order to win new customer contracts for the supply of natural gas, LNG, steam or power. This strategy requires us to invest capital and time to develop a project in exchange for the ability to sell our products and generate fees from customers in the future. When we develop these projects, our required capital expenditure may be significant, and we typically do not generate meaningful fees from customers until the project has commenced commercial operations, which may take a year or more to achieve. If the project is not successfully developed for any reason, we face the risk of not recovering some or all of our invested capital, which may be significant. If the project is successfully developed, we face the risks that our customers may not fulfill their payment obligations or may not fulfill other performance obligations that impact our ability to collect payment. Our customer contracts and development agreements do not fully protect us against this risk and, in some instances, may not provide any meaningful protection from this risk. This risk is heightened in foreign jurisdictions, particularly if our counterparty is a government or government-related entity because any attempt to enforce our contractual or other rights may involve long and costly litigation where the ultimate outcome is uncertain. If we invest capital in a project where we do not receive the payments we expect, we will have less capital to invest in other projects, our liquidity, results of operations and financial condition could be materially and adversely affected, and we could face the inability to comply with the terms of our existing debt or other agreements, which would exacerbate these adverse effects. Failure to maintain sufficient working capital could limit our growth and harm our business, financial condition and results of operations. We have significant working capital requirements, primarily driven by the delay between the purchase of and payment for natural gas and the extended payment terms that we offer our customers. Differences between the date when we pay our suppliers and the date when we receive payments from our customers may adversely affect our liquidity and our cash flows. We expect our working capital needs to increase as our total business increases. If we do not have sufficient working capital, we may not be able to pursue our growth strategy, respond to competitive pressures or fund key strategic initiatives, such as the development of our facilities, which may harm our business, financial condition and results of operations. Our ability to generate revenues is substantially dependent on our current and future long-term agreements and the performance by customers under such agreements. Our business strategy relies upon our ability to successfully market our products to our existing and new customers and enter into or replace our long-term supply and services agreements for the sale of natural gas, LNG, steam and power. If we contract with our customers on short-term contracts, our pricing can be subject to more fluctuations and less favorable terms, and our earnings are likely to become more volatile. An increasing emphasis on the short-term or spot LNG market may in the future require us to enter into contracts based on variable market prices, as opposed to contracts based on a fixed rate, which could result in a decrease in its cash flow in periods when the market price for shipping LNG is depressed or insufficient funds are available to cover its financing costs for related vessels. Our ability to generate cash is dependent on these customers continued willingness and ability to continue purchasing our products and services and to perform their obligations under their respective contracts. Their obligations may include certain nomination or operational responsibilities, construction or maintenance of their own facilities which are necessary to enable us to deliver and sell natural gas or LNG, and compliance with certain contractual representations and warranties. Further, adverse economic conditions in our industry increase the risk of nonpayment and nonperformance by customers, particularly customers that have sub-investment grade credit ratings. The COVID-19 pandemic could adversely impact our customers through decreased demand for power due to decreased economic activity and tourism, or through the adverse economic impact of the pandemic on their power customers. The impact of the COVID-19 pandemic, including governmental and other third -party responses thereto, on our customers could enhance the risk of nonpayment by such customers under our contracts, which would negatively affect our business, results of operations and financial condition. In particular, JPS and SJPC, which are public utility companies in Jamaica, could be subject to austerity measures imposed on Jamaica by the International Monetary Fund (the IMF) and other international lending organizations. Jamaica is currently subject to certain public spending limitations imposed by agreements with the IMF, and any changes under these agreements could limit JPSs and SJPCs ability to make payments under their long-term GSAs and, in the case of JPS, its ability to make payments under its PPA, with us . In addition, PREPA is currently subject to bankruptcy proceedings pending in the U.S. District Court for the District of Puerto Rico. As a result, PREPAs ability to meet its payment obligations under its contracts will be largely dependent upon funding from federal sources. Specifically, PREPAs contracting practices in connection with restoration and repair of PREPAs electrical grid in Puerto Rico, and the terms of certain of those contracts, have been subject to comment and are the subject of review and hearings by U.S. federal and Puerto Rican governmental entities. Certain of our subsidiaries are counterparties to contracts with governmental entities, including PREPA. Although these contracts require payment and performance of certain obligations, we remain subject to the statutory limitations on enforcement of those contractual provisions that protect these governmental entities. In the event that PREPA or any applicable governmental counterparty does not have or does not obtain the funds necessary to satisfy their obligations to us under our agreements, or if they terminate our agreements prior to the end of the agreed term, our financial condition, results of operations and cash flows could be materially and adversely affected. If any of these customers fails to perform its obligations under its contract for the reasons listed above or for any other reason, our ability to provide products or services and our ability to collect payment could be negatively impacted, which could materially adversely affect our operating results, cash flow and liquidity, even if we were ultimately successful in seeking damages from such customer for a breach of contract. Our current lack of asset and geographic diversification could have an adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects. Our results of operations for the year ended December 31, 2022, include our Montego Bay Facility, Old Harbour Facility, San Juan Facility, certain industrial end-users and our Miami Facility. In addition, we placed a portion of our La Paz Facility into service in 2022, and our revenue and results of operations have begun to be impacted by operations in Mexico, including agreements with certain power generation facilities in Baja California Sur. Our results for 2022 exclude other developments, including our Puerto Sandino Facility, the Barcarena Facility, Santa Catarina Facility and Ireland Facility. Jamaica, Mexico and Puerto Rico have historically experienced economic volatility and the general condition and performance of their economies, over which we have no control, may affect our business, financial condition and results of operations. Jamaica, Mexico and Puerto Rico are subject to acts of terrorism or sabotage and natural disasters, in particular hurricanes, extreme weather conditions, crime and similar other risks which may negatively impact our operations in the region. See Risks Related to the Jurisdictions in Which We OperateWe are subject to the economic, political, social and other conditions in the jurisdictions in which we operate. We may also be affected by trade restrictions, such as tariffs or other trade controls. Additionally, tourism is a significant driver of economic activity in these geographies and directly and indirectly affects local demand for our LNG and therefore our results of operations. Trends in tourism in these geographies are primarily driven by the economic condition of the tourists home country or territory, the condition of their destination, and the availability, affordability and desirability of air travel and cruises. Additionally, unexpected factors could reduce tourism at any time, including local or global economic recessions, terrorism, travel restrictions, pandemics, including the COVID-19 pandemic, severe weather or natural disasters. Due to our current lack of asset and geographic diversification, an adverse development at our operating facilities, in the energy industry or in the economic conditions in these geographies, would have a significantly greater impact on our financial condition and operating results than if we maintained more diverse assets and operating areas. Because we are currently dependent upon a limited number of customers, the loss of a significant customer could adversely affect our operating results. Our current results of operations and liquidity are, and will continue to be in the near future, substantially dependent upon a limited number of customers, including JPS (as defined herein), SJPC (as defined herein) and PREPA (as defined herein), which have each entered into long-term GSAs and, in the case of JPS, a PPA in relation to the power produced at the CHP Plant (as defined herein), with us, and Jamalco (as defined herein), which has entered into a long-term SSA with us, and which represent a substantial majority of our income. Our operating results are currently contingent on our ability to maintain LNG, natural gas, steam and power sales to these customers. Our near-term ability to generate cash is dependent on these customers continued willingness and ability to continue purchasing our products and services and to perform their obligations under their respective contracts. The loss of any of these customers could have an adverse effect on our revenues and we may not be able to enter into a replacement agreement on terms as favorable as the terminated agreement. We may be unable to accomplish our business plan to diversify and expand our customer base by attracting a broad array of customers, which could negatively affect our business, results of operations and financial condition. We may not be able to convert our anticipated customer pipeline into binding long-term contracts, and if we fail to convert potential sales into actual sales, we will not generate the revenues and profits we anticipate. We are actively pursuing a significant number of new contracts for the sale of LNG, natural gas, steam, and power with multiple counterparties in multiple jurisdictions. Counterparties commemorate their purchasing commitments for these products in various degrees of formality ranging from traditional contracts to less formal arrangements, including non-binding letters of intent, non-binding memorandums of understanding, non-binding term sheets and responding to requests for proposals with potential customers. These agreements and any award following a request for proposals are subject to negotiating final definitive documents. The negotiation process may cause us or our potential counterparty to adjust the material terms of the agreement, including the price, term, schedule and any related development obligations. We cannot assure you if or when we will enter into binding definitive agreements for transactions initially described in non-binding agreements, and the terms of our binding agreements may differ materially from the terms of the related non-binding agreements. In addition, the effectiveness of our binding agreements can be subject to a number of conditions precedent that may not materialize, rendering such agreements non-effective. Moreover, while certain of our long-term contracts contain minimum volume commitments, our expected sales to customers under existing contracts may be substantially in excess of such minimum volume commitments. Our near-term ability to generate cash is dependent on these customers continued willingness and ability to nominate in excess of such minimum quantities and to perform their obligations under their respective contracts. Given the variety of sales processes and counterparty acknowledgements of the volumes they will purchase, we sometimes identify potential sales volumes as being either Committed or In Discussion. Committed volumes generally refer to the volumes that management expects to be sold under binding contracts or awards under requests for proposals. In Discussion volumes generally refer to volumes related to potential customers that management is actively negotiating, responding to a request for proposals, or with respect to which management anticipates a request for proposals or competitive bid process to be announced based on discussions with potential customers. Managements estimations of Committed and In Discussion volumes may prove to be incorrect. Accordingly, we cannot assure you that Committed or In Discussion volumes will result in actual sales, and such volumes should not be used to predict the Companys future results. We may never sign a binding agreement to sell our products to the counterparty, or we may sell much less volume than we estimate, which could result in our inability to generate the revenues and profits we anticipate, having a material adverse effect on our results of operations and financial condition. Our contracts with our customers are subject to termination under certain circumstances. Our contracts with our customers contain various termination rights. For example, each of our long-term customer contracts, including the contracts with JPS, SJPC, Jamalco and PREPA, contain various termination rights allowing our customers to terminate the contract, including, without limitation: upon the occurrence of certain events of force majeure; if we fail to make available specified scheduled cargo quantities; the occurrence of certain uncured payment defaults; the occurrence of an insolvency event; the occurrence of certain uncured, material breaches; and if we fail to commence commercial operations or achieve financial close within the agreed timeframes. We may not be able to replace these contracts on desirable terms, or at all, if they are terminated. Contracts that we enter into in the future may contain similar provisions. If any of our current or future contracts are terminated, such termination could have a material adverse effect on our business, contracts, financial condition, operating results, cash flows, liquidity and prospects. Competition in the LNG industry is intense, and some of our competitors have greater financial, technological and other resources than we currently posse ss. A substantial majority of our revenue in 2022 was dependent upon our LNG sales to third parties. We operate in the highly competitive industry for LNG and face intense competition from independent, technology-driven companies as well as from both major and other independent oil and natural gas companies and utilities, in the various markets in which we operate and many of which have been in operation longer than us. Various factors relating to competition may prevent us from entering into new or replacement customer contracts on economically comparable terms to existing customer contracts, or at all, including , among others: increases in worldwide LNG production capacity and availability of LNG for market supply; increases in demand for natural gas but at levels below those required to maintain current price equilibrium with respect to supply; increases in the cost to supply natural gas feedstock to our liquefaction projects; increases in the cost to supply LNG feedstock to our facilities; decreases in the cost of competing sources of natural gas, LNG or alternate fuels such as coal, heavy fuel oil and automotive diesel oil ("ADO"); decreases in the price of LNG; and displacement of LNG or fossil fuels more broadly by alternate fuels or energy sources or technologies (including but not limited to nuclear, wind, solar, biofuels and batteries) in locations where access to these energy sources is not currently available or prevalent. In addition, we may not be able to successfully execute on our strategy to supply our existing and future customers with LNG produced primarily at our own liquefaction facilities upon completion of the Pennsylvania Facility or through our Fast LNG solution. Various competitors have and are developing LNG facilities in other markets, which will compete with our LNG facilities, including our Fast LNG solution. Some of these competitors have longer operating histories, more development experience, greater name recognition, larger staffs, larger and more versatile fleets, and substantially greater financial, technical and marketing resources than we currently possess. We also face competition for the contractors needed to build our facilities and skilled employees. See We may experience increased labor costs and regulation, and the unavailability of skilled workers or our failure to attract and retain qualified personnel, as well as our ability to comply with such labor laws, could adversely affect us. The superior resources that some of these competitors have available for deployment could allow them to compete successfully against us, which could have a material adverse effect on our business, ability to realize benefits from future projects, results of operations, financial condition, liquidity and prospects. We anticipate that an increasing number of offshore transportation companies, including many with strong reputations and extensive resources and experience will enter the LNG transportation market and the FSRU market. This increased competition may cause greater price competition for our products. As a result of these factors, we may be unable to expand our relationships with existing customers or to obtain new customers on a favorable basis, if at all, which would have a material adverse effect on our business, results of operations and financial condition. Cyclical or other changes in the demand for and price of LNG and natural gas may adversely affect our business and the performance of our customers. Our business and the development of energy-related infrastructure and projects generally is based on assumptions about the future availability and price of natural gas and LNG and the prospects for international natural gas and LNG markets. Natural gas and LNG prices have at various times been and may become volatile due to one or more of the following factors: additions to competitive regasification capacity in North America, Brazil, Europe, Asia and other markets, which could divert LNG or natural gas from our business; imposition of tariffs by China or any other jurisdiction on imports of LNG from the United States; insufficient or oversupply of natural gas liquefaction or export capacity worldwide; insufficient LNG tanker capacity; weather conditions and natural disasters; reduced demand and lower prices for natural gas; increased natural gas production deliverable by pipelines, which could suppress demand for LNG; decreased oil and natural gas exploration activities, including shut-ins and possible proration, which may decrease the production of natural gas; cost improvements that allow competitors to offer LNG regasification services at reduced prices; changes in supplies of, and prices for, alternative energy sources, such as coal, oil, nuclear, hydroelectric, wind and solar energy, which may reduce the demand for natural gas; changes in regulatory, tax or other governmental policies regarding imported or exported LNG, natural gas or alternative energy sources, which may reduce the demand for imported or exported LNG and/or natural gas; political conditions in natural gas producing regions; adverse relative demand for LNG compared to other markets, which may decrease LNG imports into or exports from North America; and cyclical trends in general business and economic conditions that cause changes in the demand for natural gas. Adverse trends or developments affecting any of these factors, including the timing of the impact of these factors in relation to our purchases and sales of natural gas and LNG could result in increases in the prices we have to pay for natural gas or LNG, which could materially and adversely affect the performance of our customers, and could have a material adverse effect on our business, contracts, financial condition, operating results, cash flows, liquidity and prospects. The COVID-19 pandemic and certain actions by the Organization of Petroleum Exporting Countries ("OPEC") related to the supply of oil in the market have caused volatility and disruption in the price of oil which may negatively impact our potential customers willingness or ability to enter into new contracts for the purchase of natural gas. Additionally, in situations where our supply chain has capacity constraints and as a result we are unable to receive all volumes under our long-term LNG supply agreements, our supplier may sell volumes of LNG in a mitigation sale to third parties. In these cases, the factors above may impact the price and amount we receive under mitigation sales and we may incur losses that would have an adverse impact on our financial condition, results of operations and cash flows. Conversely, current market conditions have increased LNG values to historically high levels. The elevated market values could increase the economic incentives an LNG seller has to fail to deliver LNG cargos to us if they can sell the same LNG cargos at a higher price to another buyer in the market after giving effect to any contractual penalties the seller would owe to us for failing to deliver. Our contracts may not require an LNG seller to compensate us for the full current market value of an LNG cargo that we have purchased, and if so, we may not be contractually entitled to receive full economic indemnification upon an LNG seller's failure to deliver an LNG cargo to us. Recently, the LNG industry has experienced increased volatility. If market disruptions and bankruptcies of third-party LNG suppliers and shippers negatively impacts our ability to purchase a sufficient amount of LNG or significantly increases our costs for purchasing LNG, our business, operating results, cash flows and liquidity could be materially and adversely affected. There can be no assurance we will achieve our target cost or pricing goals. In particular, because we have not currently procured fixed-price, long-term LNG supply to meet all future customer demand, increases in LNG prices and/or shortages of LNG supply could adversely affect our profitability. Our actual costs and any profit realized on the sale of our LNG may vary from the estimated amounts on which our contracts for feedgas were originally based. There is inherent risk in the estimation process, including significant changes in the demand for and price of LNG as a result of the factors listed above, many of which are outside of our control. If LNG were to become unavailable for current or future volumes of natural gas due to repairs or damage to supplier facilities or tankers, lack of capacity, impediments to international shipping or any other reason, our ability to continue delivering natural gas, power or steam to end-users could be restricted, thereby reducing our revenues. Any permanent interruption at any key LNG supply chains that caused a material reduction in volumes transported on or to our tankers and facilities could have a material adverse effect on our business, financial condition, operating results, cash flow, liquidity and prospects. Our risk management strategies cannot eliminate all LNG price and supply risks. In addition, any non-compliance with our risk management strategies could result in significant financial losses. Our strategy is to maintain a manageable balance between LNG purchases, on the one hand, and sales or future delivery obligations, on the other hand. Through these transactions, we seek to earn a margin for the LNG purchased by selling LNG for physical delivery to third-party users, such as public utilities, shipping/marine cargo companies, industrial users, railroads, trucking fleets and other potential end-users converting from traditional ADO or oil fuel to natural gas. These strategies cannot, however, eliminate all price risks. For example, any event that disrupts our anticipated supply chain could expose us to risk of loss resulting from price changes if we are required to obtain alternative supplies to cover these transactions. We are also exposed to basis risks when LNG is purchased against one pricing index and sold against a different index. Moreover, we are also exposed to other risks, including price risks on LNG we own, which must be maintained in order to facilitate transportation of the LNG to our customers or to our facilities. If we were to incur a material loss related to commodity price risks, it could have a material adverse effect on our financial position, results of operations and cash flows. Any use of hedging arrangements may adversely affect our future operating results or liquidity. To reduce our exposure to fluctuations in the price, volume and timing risk associated with the purchase of natural gas, we have entered and may in the future enter into futures, swaps and option contracts traded or cleared on the Intercontinental Exchange and the New York Mercantile Exchange or over-the-counter (OTC) options and swaps with other natural gas merchants and financial institutions. Hedging arrangements would expose us to risk of financial loss in some circumstances, including when expected supply is less than the amount hedged, the counterparty to the hedging contract defaults on its contractual obligations, or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. The use of derivatives also may require the posting of cash collateral with counterparties, which can impact working capital when commodity prices change. We are dependent on third-party LNG suppliers and may not be able to purchase or receive physical delivery of LNG or natural gas in sufficient quantities and/or at economically attractive prices to satisfy our delivery obligations under the GSAs, PPAs and SSAs. Under our GSAs, PPAs and SSAs, we are required to deliver to our customers specified amounts of LNG, natural gas, power and steam, respectively, at specified times and within certain specifications, all of which requires us to obtain sufficient amounts of LNG from third-party LNG suppliers or our own portfolio. We may not be able to purchase or receive physical delivery of sufficient quantities of LNG to satisfy those delivery obligations, which may provide a counterparty with the right to terminate its GSA, PPA or SSA, as applicable, or subject us to penalties and indemnification obligations un der those agreements. While we have entered into supply agreements for the purchase of LNG between 2023 and 2030, we may need to purchase significant additional LNG volumes to meet our delivery obligations to our downstream customers. Price fluctuations in natural gas and LNG may make it expensive or uneconomical for us to acquire adequate supply of these items or to sell our inventory of natural gas or LNG at attractive prices. Failure to secure contracts for the purchase of a sufficient amount of LNG or at favorable prices could materially and adversely affect our business, operating results, cash flows and liquidity. Additionally, we are dependent upon third-party LNG suppliers and shippers and other tankers and facilities to provide delivery options to and from our tankers and energy-related infrastructure. If any third parties were to default on their obligations under our contracts or seek bankruptcy protection, we may not be able to replace such contracts or purchase LNG on the spot market or receive a sufficient quantity of LNG in order to satisfy our delivery obligations under our GSAs, PPAs and SSAs or at favorable terms. Under tanker charters, we will be obligated to make payments for our chartered tankers regardless of use. We may not be able to enter into contracts with purchasers of LNG in quantities equivalent to or greater than the amount of tanker capacity we have purchased, as our vessels maybe be too small for those obligations. Any such failure to purchase or receive delivery of LNG or natural gas in sufficient quantities could result in our failure to satisfy our obligations to our customers, which could lead to losses, penalties, indemnification and potentially a termination of agreements with our customers. Furthermore, we may seek to litigate any such breaches by our third-party LNG suppliers and shippers. Such legal proceedings may involve claims for substantial amounts of money and we may not be successful in pursing such claims. Even if we are successful, any litigation may be costly and time-consuming. If any such proceedings were to result in an unfavorable outcome, we may not be able to recover our losses (including lost profits) or any damages sustained from our agreements with our customers. See General RisksWe are and may be involved in legal proceedings and may experience unfavorable outcomes . These actions could also expose us to adverse publicity, which might adversely affect our reputation and therefore, our results of operations. Further, if, it could have an adverse effect on our business, operating results, cash flows and liquidity, which could in turn materially and adversely affect our liquidity to make payments on our debt or comply with our financial ratios and other covenants. See W e have incurred, and may in the future incur, a significant amount of debt . We may not be able to fully utilize the capacity of our FSRUs and other facilities. Our FSRU facilities have significant excess capacity that is currently not dedicated to a particular anchor customer. Part of our business strategy is to utilize undedicated excess capacity of our FSRU facilities to serve additional downstream customers in the regions in which we operate. However, we have not secured, and we may be unable to secure, commitments for all of our excess capacity. Factors which could cause us to contract less than full capacity include difficulties in negotiations with potential counterparties and factors outside of our control such as the price of and demand for LNG. Failure to secure commitments for less than full capacity could impact our future revenues and materially adversely affect our business, financial condition and operating results. LNG that is processed and/or stored on FSRUs and transported via pipeline is subject to risk of loss or damage. LNG processed and stored on FSRUs may be subject to loss or damage resulting from equipment malfunction, faulty handling, ageing or otherwise. Where we have chartered in, but subsequently not outchartered an FSRU, which in turn results in our being unable to transfer risk of loss or damage, we could bear the risk of loss or damage to all those volumes of LNG for the period of time during which those applicable volumes of LNG are stored on an FSRU or are dispatched to a pipeline. Any such disruption to the supply of LNG and natural gas may lead to delays, disruptions or curtailments in the production of power at our facilities, which could materially and adversely affect our revenues, financial condition and results of operations. The operation of our vessels is dependent on our ability to deploy our vessels to an NFE terminal or to long-term charters. Our principal strategy for our FSRU and LNG carriers is to provide steady and reliable shipping, regasification and offshore operations to NFE terminals and, to the extent favorable to our business, replace or enter into new long-term carrier time charters for our vessels. Most requirements for new LNG projects continue to be provided on a long-term basis, though the level of spot voyages and short-term time charters of less than 12 months in duration together with medium term charters of up to five years has increased in recent years. This trend is expected to continue as the spot market for LNG expands. More frequent changes to vessel sizes, propulsion technology and emissions profile, together with an increasing desire by charterers to access modern tonnage could also reduce the appetite of charterers to commit to long-term charters that match their full requirement period. As a result, the duration of long-term charters could also decrease over time. We may also face increased difficulty entering into long-term time charters upon the expiration or early termination of our contracts. The process of obtaining long-term charters for FSRUs and LNG carriers is highly competitive and generally involves an intensive screening process and competitive bids, and often extends for several months. If we lose any of our charterers and are unable to re-deploy the related vessel to a NFE terminal or into a new replacement contract for an extended period of time, we will not receive any revenues from that vessel, but we will be required to pay expenses necessary to maintain the vessel in seaworthy operating condition and to service any associated debt. We rely on tankers and other vessels outside of our fleet for our LNG transportation and transfer. In addition to our own fleet of vessels, we rely on third-party ocean-going tankers and freight carriers (for ISO containers) for the transportation of LNG and ship-to-ship kits to transfer LNG between ships. We may not be able to successfully enter into contracts or renew existing contracts to charter tankers on favorable terms or at all, which may result in us not being able to meet our obligations. Our ability to enter into contracts or renew existing contracts will depend on prevailing market conditions upon expiration of the contracts governing the leasing or charter of the applicable assets. Therefore, we may be exposed to increased volatility in terms of charter rates and contract provisions. Fluctuations in rates result from changes in the supply of and demand for capacity and changes in the demand for seaborne carriage of commodities. Because the factors affecting the supply and demand are outside of our control and are highly unpredictable, the nature, timing, direction and degree of changes in industry conditions are also unpredictable. Likewise, our counterparties may seek to terminate or renegotiate their charters or leases with us. If we are not able to renew or obtain new charters or leases in direct continuation, or if new charters or leases are entered into at rates substantially above the existing rates or on terms otherwise less favorable compared to existing contractual terms, our business, prospects, financial condition, results of operations and cash flows could be materially adversely affected. Furthermore, our ability to provide services to our customers could be adversely impacted by shifts in tanker market dynamics, shortages in available cargo carrying capacity, changes in policies and practices such as scheduling, pricing, routes of service and frequency of service, or increases in the cost of fuel, taxes and labor, emissions standards, maritime regulatory changes and other factors not within our control. The availability of the tankers could be delayed to the detriment of our LNG business and our customers because the construction and delivery of LNG tankers require significant capital and long construction lead times. Changes in ocean freight capacity, which are outside our control, could negatively impact our ability to provide natural gas if LNG shipping capacity is adversely impacted and LNG transportation costs increase because we may bear the risk of such increases and may not be able to pass these increases on to our customers. The operation of ocean-going tankers and kits carries inherent risks. These risks include the possibility of natural disasters; mechanical failures; grounding, fire, explosions and collisions; piracy; human error; epidemics; and war and terrorism. We do not currently maintain a redundant supply of ships, ship-to-ship kits or other equipment. As a result, if our current equipment fails, is unavailable or insufficient to service our LNG purchases, production, or delivery commitments we may need to procure new equipment, which may not be readily available or be expensive to obtain. Any such occurrence could delay the start of operations of facilities we intend to commission, interrupt our existing operations and increase our operating costs. Any of these results could have a material adverse effect on our business, financial condition and operating results. Hire rates for FSRUs and LNG carriers may fluctuate substantially. If rates are lower when we are seeking a new charter, our earnings may decline. Hire rates for FSRUs and LNG carriers fluctuate over time as a result of changes in the supply-demand balance relating to current and future FSRU and LNG carrier capacity. This supply-demand relationship largely depends on a number of factors outside of our control. For example, driven in part by an increase in LNG production capacity, the market supply particularly of LNG carriers has been increasing. We believe that this and any future expansion of the global LNG carrier fleet may have a negative impact on charter hire rates, vessel utilization and vessel values, the impact of which could be amplified if the expansion of LNG production capacity does not keep pace with fleet growth. The LNG market is also closely connected to world natural gas prices and energy markets, which it cannot predict. A substantial or extended decline in demand for natural gas or LNG could adversely affect our ability to charter or re-charter our vessels at acceptable rates or to acquire and profitably operate new vessels.

Accordingly, this could have a material adverse effect on our earnings, financial condition, operating results and prospects. Vessel values may fluctuate substantially and, if these values are lower at a time when we are attempting to dispose of vessels, we may incur a loss. Vessel values can fluctuate substantially over time due to a number of different factors, including: prevailing economic conditions in the natural gas and energy markets; a substantial or extended decline in demand for LNG; increases in the supply of vessel capacity without a commensurate increase in demand; the size and age of a vessel; and the cost of retrofitting, steel or modifying existing vessels, as a result of technological advances in vessel design or equipment, changes in applicable environmental or other regulations or standards, customer requirements or otherwise. As our vessels age, the expenses associated with maintaining and operating them are expected to increase, which could have an adverse effect on our business and operations if we do not maintain sufficient cash reserves for maintenance and replacement capital expenditures. Moreover, the cost of a replacement vessel would be significant. During the period a vessel is subject to a charter, we will not be permitted to sell it to take advantage of increases in vessel values without the charterers consent. If a charter terminates, we may be unable to re-deploy the affected vessels at attractive rates or for our operations and, rather than continue to incur costs to maintain and finance them, we may seek to dispose of them. When vessel values are low, we may not be able to dispose of vessels at a reasonable price when we wish to sell vessels, and conversely, when vessel values are elevated, we may not be able to acquire additional vessels at attractive prices when we wish to acquire additional vessels, which could adversely affect our business, results of operations, cash flow, and financial condition. The carrying values of our vessels may not represent their fair market value at any point in time because the market prices of secondhand vessels tend to fluctuate with changes in charter rates and the cost of new build vessels. Our vessels are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Although we did not recognize an impairment charge on any vessels for the year ended December 31, 2022, we cannot assure you that we will not recognize impairment losses on our vessels in future years. Any impairment charges incurred as a result of declines in charter rates could negatively affect our business, financial condition, or operating results. Maritime claimants could arrest our vessels, which could interrupt our cash flow. If we are in default on certain kinds of obligations related to our vessels, such as those to our lenders, crew members, suppliers of goods and services to our vessels or shippers of cargo, these parties may be entitled to a maritime lien against one or more of our vessels. In many jurisdictions, a maritime lien holder may enforce its lien by arresting a vessel through foreclosure proceedings. In a few jurisdictions, claimants could try to assert sister ship liability against one vessel in our fleet for claims relating to another of our vessels. The arrest or attachment of one or more of our vessels could interrupt our cash flow and require us to pay to have the arrest lifted. Under some of our present charters, if the vessel is arrested or detained (for as few as 14 days in the case of one of our charters) as a result of a claim against us, we may be in default of our charter and the charterer may terminate the charter. This would negatively impact our revenues and cash flows. We seek to develop innovative and new technologies as part of our strategy that are not yet proven and may not realize the time and cost savings we expect to achieve. We analyze and seek to implement innovative and new technologies that complement our businesses to reduce our costs, achieve efficiencies for our business and our customers and advance our long-term goals, such as our ISO container distribution system, our Fast LNG solution and our green hydrogen project. The success of our current operations and future projects will depend in part on our ability to create and maintain a competitive position in the natural gas liquefaction industry. We have developed our Fast LNG strategy to procure and deliver LNG to our customers more quickly and cost-effectively than traditional LNG procurement and delivery strategies used by other market participants. See Our Fast LNG technology is not yet proven and we may not be able to implement it as planned or at all . We are also making investments to develop green hydrogen energy technologies as part of our long-term goal to become one of the worlds leading providers of carbon-free energy. We continue to develop our ISO container distribution systems in the various markets where we operate. We expect to make additional investments in this field in the future. Because these technologies are innovative, we may be making investments in unproven business strategies and technologies with which we have limited or no prior development or operating experience. As an investor in these technologies, it is also possible that we could be exposed to claims and liabilities, expenses, regulatory challenges and other risks. We may not be able to successfully develop these technologies, and even if we succeed, we may ultimately not be able to realize the time, revenues and cost savings we currently expect to achieve from these strategies, which could adversely affect our financial results. Technological innovation may impair the economic attractiveness of our projects. The success of our current operations and future projects will depend in part on our ability to create and maintain a competitive position in the natural gas liquefaction industry. In particular, although we plan to build out our delivery logistics chain in Northern Pennsylvania using proven technologies such as those currently in operation at our Miami Facility, we do not have any exclusive rights to any of these technologies. In addition, such technologies may be rendered obsolete or uneconomical by legal or regulatory requirements, technological advances, more efficient and cost-effective processes or entirely different approaches developed by one or more of our competitors or others, which could materially and adversely affect our business, ability to realize benefits from future projects, results of operations, financial condition, liquidity and prospects. Our Fast LNG technology is not yet proven and we may not be able to implement it as planned or at all. We have developed our Fast LNG strategy to procure and deliver LNG to our customers more quickly and cost-effectively than traditional LNG procurement and delivery strategies used by other market participants. Our ability to create and maintain a competitive position in the natural gas liquefaction industry may be adversely affected by our inability to effectively implement our Fast

LNG technology. We are finalizing construction of our first Fast LNG solution, and are therefore subject to construction risks, risks associated with third-party contracting and service providers, permitting and regulatory risks. See We are subject to various construction risks and We depend on third-party contractors, operators and suppliers . Because our Fast LNG technology has not been previously implemented, tested or proven, we are also exposed to unknown and unforeseen risks associated with the development of new technologies, including failure to meet design, engineering, or performance specifications, incompatibility of systems, inability to contract or employ third parties with sufficient experience in technologies used or inability by contractors to perform their work, delays and schedule changes, high costs and expenses that may be subject to increase or difficult to anticipate, regulatory and legal challenges, instability or clarity of application of laws, rules and regulations to the technology, and added difficulties in obtaining or securing required permits or authorizations, among others. See F ailure to obtain and maintain permits, approvals and authorizations from governmental and regulatory agencies and third parties on favorable terms could impede operations and construction . The success and profitability of our Fast LNG technology is also dependent on the volatility of the price of natural gas and LNG compared to the related levels of capital spending required to implement the technology. Natural gas and LNG prices have at various times been and may become volatile due to one or more factors. Volatility or weakness in natural gas or LNG prices could render our LNG procured through Fast LNG too expensive for our customers, and we may not be able to obtain our anticipated return on our investment or make our technology profitable. In addition, we may seek to construct and develop floating offshore liquefaction units as part of our Fast LNG in jurisdictions which could potentially expose us to increased political, economic, social and legal instability, a lack of regulatory clarity of application of laws, rules and regulations to our technology, or additional jurisdictional risks related to currency exchange, tariffs and other taxes, changes in laws, civil unrest, and similar risks. See Risks Related to the Jurisdictions in which we OperateWe are subject to the economic, political, social and other conditions in the jurisdictions in which we operate. Furthermore, as part of our business strategy for Fast LNG, we may enter into tolling agreements with third parties, including in developing countries, and these counterparties may have greater credit risk than typical. Therefore, we may be exposed to greater customer credit risk than other companies in the industry. Our credit procedures and policies may be inadequate to sufficiently eliminate risks of nonpayment and nonperformance. We may not be able to successfully develop, construct and implement our Fast LNG solution, and even if we succeed in developing and constructing the technology, we may ultimately not be able to realize the cost savings and revenues we currently expect to achieve from it, which could result in a material adverse effect upon our operations and business. We have incurred, and may in the future incur, a significant amount of debt. On an ongoing basis, we engage with lenders and other financial institutions in an effort to improve our liquidity and capital resources. As of December 31, 2022, we had approximately $4,582 million aggregate principal amount of indebtedness outstanding on a consolidated basis. The terms and conditions of our indebtedness include restrictive covenants that may limit our ability to operate our business, to incur or refinance our debt, engage in certain transactions, and require us to maintain certain financial ratios, among others, any of which may limit our ability to finance future operations and capital needs, react to changes in our business and in the economy generally, and to pursue business opportunities and activities. If we fail to comply with any of these restrictions or are unable to pay our debt service when due, our debt could be accelerated or cross-accelerated, and we cannot assure you that we will have the ability to repay such accelerated debt. Any such default could also have adverse consequences to our status and reporting requirements, reducing our ability to quickly access the capital markets. Our ability to service our existing and any future debt will depend on our performance and operations, which is subject to factors that are beyond our control and compliance with covenants in the agreements governing such debt. We may incur additional debt to fund our business and strategic initiatives. If we incur additional debt and other obligations, the risks associated with our substantial leverage and the ability to service such debt would increase, which could have a material adverse effect on our business, results of operation and financial condition. Our business is dependent upon obtaining substantial additional funding from various sources, which may not be available or may only be available on unfavorable terms. We believe we will have sufficient liquidity, cash flow from operations and access to additional capital sources to fund our capital expenditures and working capital needs for the next 12 months and the reasonably foreseeable future. In the future, we expect to incur additional indebtedness to assist us in developing our operations and we are considering alternative financing options, including in specific markets or the opportunistic sale of one of our non-core assets. We also historically have relied, and in the future will likely rely, on borrowings under term loans and other debt instruments to fund our capital expenditures. If any of the lenders in the syndicates backing these debt instruments were unable to perform on its commitments, we may need to seek replacement financing. We cannot assure you that such additional funding will be available on acceptable terms, or at all. Our ability to raise additional capital on acceptable terms will depend on financial, economic and market conditions, which have increased in volatility and at times have been negatively impacted due to the COVID-19 pandemic, our progress in executing our business strategy and other factors, many of which are beyond our control, including domestic or international economic conditions, increases in key benchmark interest rates and/or credit spreads, the adoption of new or amended banking or capital market laws or regulations, the re-pricing of market risks and volatility in capital and financial markets, risks relating to the credit risk of our customers and the jurisdictions in which we operate, as well as general risks applicable to the energy sector. Additional debt financing, if available, may subject us to increased restrictive covenants that could limit our flexibility in conducting future business activities and could result in us expending significant resources to service our obligations. Additionally, we may need to adjust the timing of our planned capital expenditures and facilities development depending on the requirements of our existing financing and availability of such additional funding. If we are unable to obtain additional funding, approvals or amendments to our financings outstanding from time to time, or if additional funding is only available on terms that we determine are not acceptable to us, we may be unable to fully execute our business plan, we may be unable to pay or refinance our indebtedness or to fund our other liquidity needs, and our financial condition or results of operations may be materially adversely affected. We have entered into, and may in the future enter into or modify existing, joint ventures that might restrict our operational and corporate flexibility or require credit support. We have entered into, and may in the future enter, into joint venture arrangements with third parties in respect of our projects and assets. In August 2022, we established Energos, as a joint venture platform with certain funds or investment vehicles managed by Apollo, for the development of a global marine infrastructure platform, of which we own 20%. As we do not operate the assets owned by these joint ventures, our control over their operations is limited by provisions of the agreements we have entered into with our joint venture partners and by our percentage ownership in such joint ventures. Because we do not control all of the decisions of our joint ventures, it may be difficult or impossible for us to cause the joint venture to take actions that we believe would be in its or the joint ventures best interests. For example, we cannot unilaterally cause the distribution of cash by our joint ventures. Additionally, as the joint ventures are separate legal entities, any right we may have to receive assets of any joint venture or other payments upon their liquidation or reorganization will be effectively subordinated to the claims of the creditors of that joint venture (including tax authorities, trade creditors and any other third parties that require such subordination, such as lenders and other creditors). Moreover, joint venture arrangements involve various risks and uncertainties, such as our commitment to fund operating and/or capital expenditures, the timing and amount of which we may not control, and our joint venture partners may not satisfy their financial obligations to the joint venture. We have provided and may in the future provide guarantees or other forms of credit support to our joint ventures and/or affiliates. Failure by any of our joint ventures, equity method investees and/or affiliate to service their debt requirements and comply with any provisions contained in their commercial loan agreements, including paying scheduled installments and complying with certain covenants, may lead to an event of default under the related loan agreement. As a result, if our joint ventures, equity method investees and/or affiliates are unable to obtain a waiver or do not have enough cash on hand to repay the outstanding borrowings, the relevant lenders may foreclose their liens on the relevant assets or vessels securing the loans or seek repayment of the loan from us, or both. Either of these possibilities could have a material adverse effect on our business. Further, by virtue of our guarantees with respect to our joint ventures and/or affiliates, this may reduce our ability to gain future credit from certain lenders. The swaps regulatory and other provisions of the Dodd-Frank Act and the rules adopted thereunder and other regulations, including

EMIR and REMIT, could adversely affect our ability to hedge risks associated with our business and our operating results and cash flows. We have entered and may in the future enter into futures, swaps and option contracts traded or cleared on the Intercontinental Exchange and the New York Mercantile Exchange or OTC options and swaps with other natural gas merchants and financial institutions. Title VII of the Dodd-Frank Act established federal regulation of the OTC derivatives market and made other amendments to the Commodity Exchange Act that are relevant to our business. The provisions of Title VII of the Dodd-Frank Act and the rules adopted thereunder by the Commodity Futures Trading Commission (the CFTC), the SEC and other federal regulators may adversely affect the cost and availability of the swaps that we may use for hedging, including, without limitation, rules setting limits on the positions in certain contracts, rules regarding aggregation of positions, requirements to clear through specific derivatives clearing organizations and trading platforms, requirements for posting of margins, regulatory requirements on swaps market participants. Our counterparties that are also subject to the capital requirements set out by the Basel Committee on the Banking Supervision in 2011, commonly referred to as Basel III, may increase the cost to us of entering into swaps with them or, although not required to collect margin from us under the margin rules, require us to post collateral with them in connection with such swaps in order to offset their increased capital costs or to reduce their capital costs to maintain those swaps on their balance sheets. Our subsidiaries and affiliates operating in Europe and the Caribbean may be subject to the European Market Infrastructure Regulation (EMIR) and the Regulation on Wholesale Energy Market Integrity and Transparency (REMIT) as wholesale energy market participants, which may impose increased regulatory obligations, including a prohibition to use or disclose insider information or to engage in market manipulation in wholesale energy markets, and an obligation to report certain data, as well as requiring liquid collateral. These regulations could significantly increase the cost of derivative contracts (including through requirements to post margin or collateral), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against certain risks that we encounter, and reduce our ability to monetize or restructure derivative contracts and to execute our hedging strategies. If, as a result of the swaps regulatory regime discussed above, we were to forgo the use of swaps to hedge our risks, such as commodity price risks that we encounter in our operations, our operating results and cash flows may become more volatile and could be otherwise adversely affected. We may incur impairments to long-lived assets. We test our long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of these assets may not be recoverable. Significant negative industry or economic trends, decline of our market capitalization, reduced estimates of future cash flows for our business segments or disruptions to our business, or adverse actions by governmental entities, changes to regulation or legislation could lead to an impairment charge of our long-lived assets. Our valuation methodology for assessing impairment requires management to make judgments and assumptions based on historical experience and to rely heavily on projections of future operating performance. Projections of future operating results and cash flows may vary significantly from results. In addition, if our analysis results in an impairment to our long-lived assets, we may be required to record a charge to earnings in our consolidated financial statements during a period in which such impairment is determined to exist, which may negatively impact our operating results. Weather events or other natural or manmade disasters or phenomena, some of which may be adversely impacted by global climate change, could have a material adverse effect on our operations and projects, as well as on the economies in the markets in which we operate or plan to operate. Weather events such as storms and related storm activity and collateral effects, or other disasters, accidents, catastrophes or similar events, natural or manmade, such as explosions, fires, seismic events, floods or accidents, could result in damage to our facilities, liquefaction facilities, or related infrastructure, interruption of our operations or our supply chain, as well as delays or cost increases in the construction and the development of our proposed facilities or other infrastructure. Changes in the global climate may have significant physical effects, such as increased frequency and severity of storms, floods and rising sea levels; if any such effects were to occur, they could have an adverse effect on our onshore and offshore operations. Due to the nature of our operations, we are particularly exposed to the risks posed by hurricanes, tropical storms and their collateral effects, in particular with respect to fleet operations, floating offshore liquefaction units and other infrastructure we may develop in connection with our Fast LNG technology. In particular, we may seek to construct and develop floating offshore liquefaction units as part of our Fast LNG in locations that are subject to risks posed by hurricanes and similar severe weather conditions or natural disasters or other adverse events or conditions that could severely affect our infrastructure, resulting in damage or loss, contamination to the areas, and suspension of our operations. For example, our operations in coastal regions in southern Florida, the Caribbean, the Gulf of Mexico and Latin America are frequently exposed to natural hazards such as sea-level rise, coastal flooding, cyclones, extreme heat, hurricanes, and earthquakes. These climate risks can affect our operations, potentially even damaging or destroying our facilities, leading to production downgrades, costly delays, reduction in workforce productivity, and potential injury to our people. In addition, jurisdictions with increased political, economic, social and legal instability, lack of regulatory clarity of application of laws, rules and regulations to our technology, and could potentially expose us to additional jurisdictional risks related to currency exchange, tariffs and other tax es, changes in laws, civil unrest, and similar risks. In addition, because of the location of some of our operations, we are subject to other natural phenomena, including earthquakes, such as the one that occurred near Puerto Rico in January 2020, which resulted in a temporary delay of development of our Puerto Rico projects, hurricanes and tropical storms. If one or more tankers, pipelines, facilities, liquefaction facilities, vessels, equipment or electronic systems that we own, lease or operate or that deliver products to us or that supply our facilities, liquefaction facilities, and customers facilities are damaged by severe weather or any other disaster, accident, catastrophe or similar event, our construction projects and our operations could be significantly interrupted, damaged or destroyed. These delays, interruptions and damages could involve substantial damage to people, property or the environment, and repairs could take a significant amount of time, particularly in the event of a major interruption or substantial damage. We do not, nor do we intend to, maintain insurance against all of these risks and losses. We may not be able to maintain desired or required insurance in the future at rates that we consider reasonable. See Our insurance may be insufficient to cover losses that may occur to our property or result from our operations . The occurrence of a significant event, or the threat thereof, could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects. Existing and future environmental, social, health and safety laws and regulations could result in increased or more stringent compliance requirements, which may be difficult to comply with or result in additional costs and may otherwise lead to significant liabilities and reputational damage. Our business is now and will in the future be subject to extensive national, federal, state, municipal and local laws, rules and regulations, in the United States and in the jurisdictions where we operate, relating to the environment, social, health and safety and hazardous substances. These requirements regulate and restrict, among other things: the siting and design of our facilities; discharges to air, land and water, with particular respect to the protection of human health, the environment and natural resources and safety from risks associated with storing, receiving and transporting LNG, natural gas and other substances; the handling, storage and disposal of hazardous materials, hazardous waste and petroleum products; and remediation associated with the release of hazardous substances. Many of these laws and regulations, such as the CAA and the CWA, and analogous laws and regulations in the jurisdictions in which we operate, restrict or prohibit the types, quantities and concentrations of substances that can be emitted into the environment in connection with the construction and operation of our facilities and vessels, and require us to obtain and maintain permits and provide governmental authorities with access to our facilities and vessels for inspection and reports related to our compliance. For example, the Pennsylvania Department of Environmental Protection laws and regulations will apply to the construction and operation of the Pennsylvania Facility. Changes or new environmental, social, health and safety laws and regulations could cause additional expenditures, restrictions and delays in our business and operations, the extent of which cannot be predicted and which may require us to limit substantially, delay or cease operations in some circumstances. For example, in October 2017, the U.S. Government Accountability Office issued a legal determination that a 2013 interagency guidance document was a rule subject to the Congressional Review Act (CRA). This legal determination could open a broader set of agency guidance documents to potential disapproval and invalidation under the CRA, potentially increasing the likelihood that laws and regulations applicable to our business will become subject to revised interpretations in the future that we cannot predict. Revised, reinterpreted or additional laws and regulations that result in increased compliance costs or additional operating or construction costs and restrictions could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects. Any failure in environmental, social, health and safety performance from our operations may result in an event that causes personal harm or injury to our employees, other persons, and/or the environment, as well as the imposition of injunctive relief and/or penalties or fines for non-compliance with relevant regulatory requirements or litigation. Such a failure, or a similar failure elsewhere in the energy industry (including, in particular, LNG liquefaction, storage, transportation or regasification operations), could generate public concern, which may lead to new laws and/or regulations that would impose more stringent requirements on our operations, have a corresponding impact on our ability to obtain permits and approvals, and otherwise jeopardize our reputation or the reputation of our industry as well as our relationships with relevant regulatory agencies and local communities. As the owner and operator of our facilities and owner or charteror of our vessels, we may be liable, without regard to fault or the lawfulness of the original conduct, for the release of certain types or quantities of hazardous substances into the environment at or from our facilities and for any resulting damage to natural resources, which could result in substantial liabilities, fines and penalties, capital expenditures related to cleanup efforts and pollution control equipment, and restrictions or curtailment of our operations. Any such liabilities, fines and penalties that exceed the limits of our insurance coverage. See Our insurance may be insufficient to cover losses that may occur to our property or result from our operations . Individually or collectively, these developments could adversely impact our ability to expand our business, including into new markets. Greenhouse Gases/Climate Change . The threat of climate change continues to attract considerable attention in the United States and around the world. Numerous proposals have been made and could continue to be made at the international, national, regional and state government levels to monitor and limit existing and future GHG emissions. As a result, our operations are subject to a series of risks associated with the processing, transportation, and use of fossil fuels and emission of GHGs. In the United States to date, no comprehensive climate change legislation has been implemented at the federal level, although various individual states and state coalitions have adopted or considered adopting legislation, regulations or other regulatory initiatives, including GHG cap and trade programs, carbon taxes, reporting and tracking programs, and emission restrictions, pollution reduction incentives, or renewable energy or low-carbon replacement fuel quotas. At the international level, the United Nations-sponsored Paris Agreement was signed by 197 countries who agreed to limit their GHG emissions through non-binding, individually-determined reduction goals every five years after 2020. The United States rejoined the Paris Agreement, effective February 19, 2021, and other countries where we operate or plan to operate, including Jamaica, Brazil, Ireland, Mexico, and Nicaragua, have signed or acceded to this agreement. However, the scope of future climate and GHG emissions-focused regulatory requirements, if any, remain uncertain.

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Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political uncertainty in the United States and worldwide. For example, based in part on the publicized climate plan and pledges by President Biden, there may be significant legislation, rulemaking, or executive orders that seek to address climate change, incentivize low-carbon infrastructure or initiatives, or ban or restrict the exploration and production of fossil fuels. For example, executive orders may be issued or federal legislation or regulatory initiatives may be adopted to achieve U.S. goals under the Paris Agreement. Climate-related litigation and permitting risks are also increasing, as a number of cities, local governments and private organizations have sought to either bring suit against oil and natural gas companies in state or federal court, alleging various public nuisance claims, or seek to challenge permits required for infrastructure development. Fossil fuel producers are also facing general risks of shifting capital availability due to stockholder concern over climate change and potentially stranded assets in the event of future, comprehensive climate and GHG-related regulation. While several of these cases have been dismissed, there is no guarantee how future lawsuits might be resolved. The adoption and implementation of new or more comprehensive international, federal or state legislation, regulations or other regulatory initiatives that impose more stringent restrictions on GHG emissions could result in increased compliance costs, and thereby reduce demand for or erode value for, the natural gas that we process and market. The potential increase in our operating costs could include new costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our GHG emissions, pay taxes related to our GHG emissions, and administer and manage a GHG emissions program. We may not be able to recover such increased costs through increases in customer prices or rates. In addition, changes in regulatory policies that result in a reduction in the demand for hydrocarbon products that are deemed to contribute to GHGs, or restrict their use, may reduce volumes available to us for processing, transportation, marketing and storage. Furthermore, political, litigation, and financial risks may result in reduced natural gas production activities, increased liability for infrastructure damages as a result of climatic changes, or an impaired ability to continue to operate in an economic manner. One or more of these developments could have a material adverse effect on our business, financial condition and results of operation. Fossil Fuels . Our business activities depend upon a sufficient and reliable supply of natural gas feedstock, and are therefore subject to concerns in certain sectors of the public about the exploration, production and transportation of natural gas and other fossil fuels and the consumption of fossil fuels more generally. For example, PHMSA has promulgated detailed regulations governing LNG facilities under its jurisdiction to address siting, design, construction, equipment, operations, maintenance, personnel qualifications and training, fire protection and security. While the Miami Facility is subject to these regulations, none of our LNG facilities currently under development are subject to PHMSAs jurisdiction, but regulators and governmental agencies in the jurisdictions in which we operate can impose similar siting, design, construction and operational requirements that can affect our projects, facilities, infrastructure and operations. Legislative and regulatory action, and possible litigation, in response to such public concerns may also adversely affect our operations. We may be subject to future laws, regulations, or actions to address such public concern with fossil fuel generation, distribution and combustion, greenhouse gases and the effects of global climate change. Our customers may also move away from using fossil fuels such as LNG for their power generation needs for reputational or perceived risk-related reasons. These matters represent uncertainties in the operation and management of our business, and could have a material adverse effect on our financial position, results of operations and cash flows. Hydraulic Fracturing . Certain of our suppliers of natural gas and LNG employ hydraulic fracturing techniques to stimulate natural gas production from unconventional geological formations (including shale formations), which currently entails the injection of pressurized fracturing fluids (consisting of water, sand and certain chemicals) into a well bore. Moreover, hydraulically fractured natural gas wells account for a significant percentage of the natural gas production in the U.S.; the U.S. Energy Information Administration reported in 2016 that hydraulically fractured wells provided two-thirds of U.S. marketed gas production in 2015. Hydraulic fracturing activities can be regulated at the national, federal or local levels, with governmental agencies asserting authority over certain hydraulic fracturing activities and equipment used in the production, transmission and distribution of oil and natural gas, including such oil and natural gas produced via hydraulic fracturing. Such authorities may seek to further regulate or even ban such activities. For example, the Delaware River Basin Commission (DRBC), a regional body created via interstate compact responsible for, among other things, water quality protection, water supply allocation, regulatory review, water conservation initiatives, and watershed planning in the Delaware River Basin, has implemented a de facto ban on hydraulic fracturing activities in that basin since 2010 pending the approval of new regulations governing natural gas production activity in the basin. More recently, the DRBC has stated that it will consider new regulations that would ban natural gas production activity, including hydraulic fracturing, in the basin. If additional levels of regulation or permitting requirements were imposed on hydraulic fracturing operations, natural gas prices in North America could rise, which in turn could materially adversely affect the relative pricing advantage that has existed in recent years in favor of domestic natural gas prices (based on Henry Hub pricing). The requirements for permits or authorizations to conduct these activities vary depending on the location where such drilling and completion activities will be conducted. Several jurisdictions have adopted or considered adopting regulations to impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing operations, or to ban hydraulic fracturing altogether. As with most permitting and authorization processes, there is a degree of uncertainty as to whether a permit will be granted, the time it will take for a permit or approval to be issued and any conditions which may be imposed in connection with the granting of the permit. See F ailure to obtain and maintain permits, approvals and authorizations from governmental and regulatory agencies and third parties on favorable terms could impede operations and construction . Certain regulatory authorities have delayed or suspended the issuance of permits or authorizations while the potential environmental impacts associated with issuing such permits can be studied and appropriate mitigation measures evaluated. In addition, some local jurisdictions have adopted or considered adopting land use restrictions, such as city or municipal ordinances, that may restrict the performance of or prohibit the well drilling in general and/or hydraulic fracturing in particular. Increased regulation or difficulty in permitting of hydraulic fracturing, and any corresponding increase in domestic natural gas prices, could materially adversely affect demand for LNG and our ability to develop commercially viable LNG facilities. Indigenous Communities . Indigenous communitiesincluding, in Brazil, Afro-indigenous (Quilombola) communitiesare subject to certain protections under international and national laws. Brazil has ratified the International Labor Organizations Indigenous and Tribal Peoples Convention (ILO Convention 169), which states that governments are to ensure that members of tribes directly affected by legislative or administrative measures, including the grant of government authorizations, such as are required for our Brazilian operations, are consulted through appropriate procedures and through their representative institutions, particularly using the principle of consultation and participation of indigenous and traditional communities under the basis of free, prior, and informed consent (FPIC). Brazilian law does not specifically regulate the FPIC process for indigenous and traditional people affected by undertakings, nor does it set forth that individual members of an affected community shall render their FPIC on an undertaking that may impact them. However, in order to obtain certain environmental licenses for our operations, we are required to comply with the requirements of, consult with, and obtain certain authorizations from a number of institutions regarding the protection of indigenous interests: IBAMA, local environmental authorities in the localities in which we operate, the Federal Public Prosecutors Office and the National Indian Foundation (Fundao Nacional do ndio or FUNAI) (for indigenous people) or Palmares Cultural Foundation (Fundao Cultural Palmares) (for Quilombola communities). Additionally, the American Convention on Human Rights (ACHR), to which Brazil is a party, sets forth rights and freedoms prescribed for all persons, including property rights without discrimination due to race, language, and national or social origin. The ACHR also provides for consultation with indigenous communities regarding activities that may affect the integrity of their land and natural resources. If Brazils legal process for consultation and the protection of indigenous rights is challenged under the ACHR and found to be inadequate, it could result in orders or judgments that could ultimately adversely impact its operations. For example, in February 2020, the Interamerican Court of Human Rights (IACtHR) found that Argentina had not taken adequate steps, in law or action, to ensure the consulting of indigenous communities and obtaining those communities free prior and informed consent for a project impacting their territories. IACtHR further found that Argentina had thus violated the ACHR due to infringements on the indigenous communities rights to property, cultural identity, a healthy environment, and adequate food and water by failing to take effective measures to stop harmful, third-party activities on the indigenous communities traditional land. As a result, IACtHR ordered Argentina, among other things, to achieve the demarcation and grant of title to the indigenous communities over their territory and the removal of third parties from the indigenous territory. We cannot predict whether this decision will result in challenges regarding the adequacy of existing Brazilian legal requirements related to the protection of indigenous rights, changes to the existing Brazilian government body consultation process, or impact our existing development agreements or negotiations for outstanding development agreements with indigenous communities in the areas in which we operate. There are several indigenous communities that surround our operations in Brazil. Certain of our subsidiaries have entered into agreements with some of these communities that mainly provide for the use of their land for our operations, provide compensation for any potential adverse impact that our operations may indirectly cause to them, and negotiations with other such communities are ongoing. If we are not able to timely obtain the necessary authorizations or obtain them on favorable terms for our operations in areas where indigenous communities reside, our relationship with these communities deteriorates in future, or that such communities do not comply with any existing agreements related to our operations, we could face construction delays, increased costs, or otherwise experience adverse impacts on its business and results of operations. Offshore operations . Our operations in international waters and in the territorial waters of other countries are regulated by extensive and changing international, national and local environmental protection laws, regulations, treaties and conventions in force in international waters, the jurisdictional waters of the countries in which we operate, as well as the countries of our vessels registration, including those governing oil spills, discharges to air and water, the handling and disposal of hazardous substances and wastes and the management of ballast water. The International Maritime Organization (IMO) International Convention for the Prevention of Pollution from Ships of 1973, as amended from time to time, and generally referred to as MARPOL, can affect operations of our chartered vessels. In addition, our chartered LNG vessels may become subject to the International Convention on Liability and Compensation for Damage in Connection with the Carriage of Hazardous and Noxious Substances by Sea (the HNS Convention), adopted in 1996 and subsequently amended by a Protocol to the HNS Convention in April 2010. Other regulations include, but are not limited to, the designation of Emission Control Areas under MARPOL, the IMO International Convention on Civil Liability for Oil Pollution Damage of 1969, as amended from time to time, the International Convention on Civil Liability for Bunker Oil Pollution Damage, the IMO International Convention for the Safety of Life at Sea of 1974, as amended from time to time, the International Safety Management Code for the Safe Operations of Ships and for Pollution Prevention, the IMO International Convention on Load Lines of 1966, as amended from time to time and the International Convention for the Control and Management of Ships Ballast Water and Sediments in February 2004. In particular, development of offshore operations of natural gas and LNG are subject to extensive environmental, industry, maritime and social regulations. For example, any development and future operation of the potential Lakach project, which would be developed as a deepwater natural gas field in Mexico, as well as the development of a new FLNG hub off the coast of Altamira, State of Tamaulipas, would be subject to regulation by Mexicos Ministry of Energy (Secretara de Energa) (SENER), Mexico's National Hydrocarbon Commission ("CNH"), the National Agency of Industrial Safety and Environmental Protection of the Hydrocarbons Sector ("ASEA"), among other relevant Mexican regulatory bodies. The laws and regulations governing activities in the Mexican energy sector have undergone significant reformation over the past decade, and the legal regulatory framework continues to evolve as SENER, the CNH and other Mexican regulatory bodies issue new regulations and guidelines as the industry develops. Such regulations are subject to change, so it is possible that SENER, the CNH or other Mexican regulatory bodies may impose new or revised requirements that could increase our operating costs and/or capital expenditures for operations in Mexican offshore waters. In addition, our operations in waters off the coast of Mexico are subject to regulation by ASEA. The laws and regulations governing the protection of health, safety and the environment from activities in the Mexican energy sector are also relatively new, having been significantly reformed in 2013 and 2014, and the legal regulatory framework continues to evolve as ASEA and other Mexican regulatory bodies issue new regulations and guidelines as the industry modernizes and adapts to market changes. Such regulations are subject to change, and it is possible that ASEA or other Mexican regulatory bodies may impose new or revised requirements that could increase our operating costs and/or capital expenditures for operations in Mexican offshore waters. Moreover, the overall trends are towards more regulations and more stringent requirements which are likely to add to our costs of doing business. For example, IMO regulations, which became applicable on January 1, 2020, limit the sulfur content of fuel oil for ships to 0.5 weight percent starting January 1, 2020, thus increasing the cost of fuel and increasing expenses for us. Likewise, the European Union is considering extending its emissions trading scheme to maritime transport to reduce GHG emissions from vessels. We contract with industry leading vessel providers in the LNG market and look for them to take the lead in maintaining compliance with all such requirements, although the terms of our charter agreements may call for us to bear some or all of the associated costs. While we believe we are similarly situated with respect to other companies that charter vessels, we cannot assure you that these requirements will not have a material effect on our business. Our chartered vessels operating in U.S. waters, now or in the future, will also be subject to various federal, state and local laws and regulations relating to protection of the environment, including the OPA, the CERCLA, the CWA and the CAA. In some cases, these laws and regulations require governmental permits and authorizations before conducting certain activities. These environmental laws and regulations may impose substantial penalties for noncompliance and substantial liabilities for pollution. Failure to comply with these laws and regulations may result in substantial civil and criminal fines and penalties. As with the industry generally, our chartered vessels operations will entail risks in these areas, and compliance with these laws and regulations, which may be subject to frequent revisions and reinterpretation, may increase our overall cost of business. We are subject to numerous governmental export laws, and trade and economic sanctions laws and regulations, and anti-corruption laws and regulation. We conduct business throughout the world, and our business activities and services are subject to various applicable import and export control laws and regulations of the United States and other countries, particularly countries in the Caribbean, Latin America, Europe and the other countries in which we seek to do business. We must also comply with trade and economic sanctions laws, including the U.S. Commerce Departments Export Administration Regulations and economic and trade sanctions regulations maintained by the U.S. Treasury Departments Office of Foreign Assets Control. For example, in 2018, U.S. legislation was approved to restrict U.S. aid to Nicaragua and between 2018 and 2022, U.S. and European governmental authorities imposed a number of sanctions against entities and individuals in or associated with the government of Nicaragua and Venezuela. Following the invasion of Ukraine by Russia in 2022, U.S. and European governmental authorities imposed a number of sanctions against entities and individuals in Russia or connected to Russia, including sanctions specifically targeting the Russian oil and gas industry. Although we take precautions to comply with all such laws and regulations, violations of governmental export control and economic sanctions laws and regulations could result in negative consequences to us, including government investigations, sanctions, criminal or civil fines or penalties, more onerous compliance requirements, loss of authorizations needed to conduct aspects of our international business, reputational harm and other adverse consequences. Moreover, it is possible that we could invest both time and capital into a project involving a counterparty who may become subject to sanctions. If any of our counterparties becomes subject to sanctions as a result of these laws and regulations, changes thereto or otherwise, we may face an array of issues, including, but not limited to, (i) having to suspend our development or operations on a temporary or permanent basis, (ii) being unable to recuperate prior invested time and capital or being subject to lawsuits, or (iii) investigations or regulatory proceedings that could be time-consuming and expensive to respond to and which could lead to criminal or civil fines or penalties. We are also subject to anti-corruption laws and regulations, including the U.S. Foreign Corrupt Practices Act (FCPA), which generally prohibit companies and their intermediaries from making improper payments to foreign officials for the purpose of obtaining or keeping business and/or other benefits. Some of the jurisdictions in which we currently, or may in the future, operate may present heightened risks for FCPA issues, such as Nicaragua, Jamaica, Brazil and Mexico or other countries in Latin America, Asia and Africa. Although we have adopted policies and procedures that are designed to ensure that we, our employees and other intermediaries comply with the FCPA, it is highly challenging to adopt policies and procedures that ensure compliance in all respects with the FCPA, particularly in high-risk jurisdictions. Developing and implementing policies and procedures is a complex endeavor. There is no assurance that these policies and procedures will work effectively all of the time or protect us against liability under anti-corruption laws and regulations, including the FCPA, for actions taken by our employees and other intermediaries with respect to our business or any businesses that we may acquire. If we are not in compliance with trade and economic sanctions laws and anti-corruption laws and regulations, including the FCPA, we may be subject to costly and intrusive criminal and civil investigations as well significant potential criminal and civil penalties and other remedial measures, including changes or enhancements to our procedures, policies and control, the imposition of an independent compliance monitor, as well as potential personnel change and disciplinary actions. In addition, non-compliance with such laws could constitute a breach of certain covenants in operational or debt agreements, and cross-default provisions in certain of our agreements could mean that an event of default under certain of our commercial agreements could trigger an event of default under our other agreements, including our debt agreements. Any adverse finding against us could also negatively affect our relationship and reputation with current and potential customers. In addition, in certain countries we serve or expect to serve our customers through third-party agents and other intermediaries. Violations of applicable import, export, trade and economic sanctions, and anti-corruption laws and regulations by these third-party agents or intermediaries may also result in adverse consequences and repercussions to us. There can be no assurance that we and our agents and other intermediaries will be in compliance with these provisions in the future. The occurrence of any of these events could have a material adverse impact on our business, results of operations, financial condition, liquidity and future business prospects. The U.S. sanctions and embargo laws and regulations vary in their application, as they do not all apply to the same covered persons or proscribe the same activities, and such sanctions and embargo laws and regulations may be amended or strengthened over time. Although we believe that we have been in compliance with all applicable sanctions, embargo and anti-corruption laws and regulations, and intend to maintain such compliance, there can be no assurance that we will be in compliance in the future, particularly as the scope of certain laws may be unclear and may be subject to changing interpretations. Any such violation could result in fines, penalties or other sanctions that could severely impact our ability to access U.S. capital markets and conduct our business. In addition, certain financial institutions may have policies against lending or extending credit to companies that have contracts with U.S. embargoed countries or countries identified by the U.S. government as state sponsors of terrorism, which could adversely affect our ability to access funding and liquidity, our financial condition and prospects. Our charterers may inadvertently violate applicable sanctions and/or call on ports located in, or engage in transactions with, countries that are subject to restrictions imposed by the U.S. or other governments, which could adversely affect its business. None of our vessels have called on ports located in countries subject to comprehensive sanctions and embargoes imposed by the U.S. government or countries identified by the U.S. government as state sponsors of terrorism. When we charter our vessels to third parties we conduct comprehensive due diligence of the charterer and include prohibitions on the charterer calling on ports in countries subject to comprehensive U.S. sanctions or otherwise engaging in commerce with such countries. However, our vessels may be sub-chartered out to a sanctioned party or call on ports of a sanctioned nation on charterers instruction, and without our knowledge or consent. If our charterers or sub-charterers violate applicable sanctions and embargo laws and regulations as a result of actions that do not involve us, those violations could in turn negatively affect our reputation and cause us to incur significant costs associated with responding to any investigation into such violations. Increasing transportation regulations may increase our costs and negatively impact our results of operations. We are developing a transportation system specifically dedicated to transporting LNG using ISO tank containers and trucks to our customers and facilities. This transportation system may include trucks that we or our affiliates own and operate. Any such operations would be subject to various trucking safety regulations in the various countries where we operate, including those which are enacted, reviewed and amended by the Federal Motor Carrier Safety Administration (FMCSA). These regulatory authorities exercise broad powers, governing activities such as the authorization to engage in motor carrier operations, driver licensing, insurance requirements, and transportation of hazardous materials. To a large degree, intrastate motor carrier operations are subject to state and/or local safety regulations that mirror federal regulations but also regulate the weight and size dimensions of loads. Any trucking operations would be subject to possible regulatory and legislative changes that may increase our costs. Some of these possible changes include changes in environmental regulations, changes in the hours of service regulations which govern the amount of time a driver may drive or work in any specific period, onboard black box recorder device requirements or limits on vehicle weight and size. In addition to increased costs, fines and penalties, any non-compliance or violation of these regulations, could result in the suspension of our operations, which could have a material adverse effect on our business and consolidated results of operations and financial position. Our chartered vessels operating in certain jurisdictions, including the United States, now or in the future, may be subject to cabotage laws, including the Merchant Marine Act of 1920, as amended (the Jones Act). Certain activities related to our logistics and shipping operations may constitute coastwise trade within the meaning of laws and regulations of the U.S. and other jurisdictions in which we operate. Under these laws and regulations, often referred to as cabotage laws, including the Jones Act in the U.S., only vessels meeting specific national ownership and registration requirements or which are subject to an exception or exemption, may engage in such coastwise trade. When we operate or charter foreign-flagged vessels, we do so within the current interpretation of such cabotage laws with respect to permitted activities for foreign-flagged vessels. Significant changes in cabotage laws or to the interpretation of such laws in the places where we operate could affect our ability to operate or charter, or competitively operate or charter, our foreign-flagged vessels in those waters. If we do not continue to comply with such laws and regulations, we could incur severe penalties, such as fines or forfeiture of any vessels or their cargo, and any noncompliance or allegations of noncompliance could disrupt our operations in the relevant jurisdiction. Any noncompliance or alleged noncompliance could have a material adverse effect on our reputation, our business, our results of operations and cash flows, and could weaken our financial condition. We do not own the land on which our projects are located and are subject to leases, rights-of-ways, easements and other property rights for our operations. We have obtained long-term leases and cor responding rights-of-way agreements and easements with respect to the land on which various of our projects are located, including the Jamaica Facilities, the pipeline connecting the Montego Bay Facility to the Bogue Power Plant (as defined herein), the Miami Facility, the San Juan Facility and the CHP Plant are situated, facilities in Brazil such as the Garuva-Itapoa pipeline connecting the TBG pipeline to the Sao Francisco do Sul terminal , rights of way to the Petrobras/Transpetro OSPAR oil pipeline facilities, among others. In addi tion, our operations will require agreements with ports proximate to our facilities capable of handling the transload of LNG direct from our occupying vessel to our transportation assets. We do not own the land on which these facilities are located. As a result, we are subject to the possibility of increased costs to retain necessary land use rights as well as applicable law and regulations, including permits and authorizations from governmental agencies or third parties. If we were to lose these rights or be required to relocate, we would not be able to continue our operations at those sites and our business could be materially and adversely affected. For example, our ability to operate the CHP Plant is dependent on our ability to enforce the related lease. General Alumina Jamaica Limited (GAJ), one of the lessors, is a subsidiary of Noble Group, which completed a financial restructuring in 2018. If GAJ is involved in a bankruptcy or similar proceeding, such proceeding could negatively impact our ability to enforce the lease. If we are unable to enforce the lease due to the bankruptcy of GAJ or for any other reason, we could be unable to operate the CHP Plant or to execute on our contracts related thereto. If we are unable to enter into favorable contracts or to obtain the necessary regulatory and land use approvals on favorable terms, we may not be able to construct and operate our assets as anticipated, or at all, which could negatively affect our business, results of operations and financial condition. We could be negatively impacted by environmental, social, and governance (ESG) and sustainability-related matters. Governments, investors, customers, employees and other stakeholders are increasingly focusing on corporate ESG practices and disclosures, and expectations in this area are rapidly evolving. We have announced, and may in the future announce, sustainability-focused goals, initiatives, investments and partnerships. These initiatives, aspirations, targets or objectives reflect our current plans and aspirations and are not guarantees that we will be able to achieve them. Our efforts to accomplish and accurately report on these initiatives and goals present numerous operational, regulatory, reputational, financial, legal, and other risks, any of which could have a material negative impact, including on our reputation and stock price. In addition, the standards for tracking and reporting on ESG matters are relatively new, have not been harmonized and continue to evolve. Our selection of disclosure frameworks that seek to align with various voluntary reporting standards may change from time to time and may result in a lack of comparative data from period to period. Moreover, our processes and controls may not always align with evolving voluntary standards for identifying, measuring, and reporting ESG metrics, our interpretation of reporting standards may differ from those of others, and such standards may change over time, any of which could result in significant revisions to our goals or reported progress in achieving such goals. In this regard, the criteria by which our ESG practices and disclosures are assessed may change due to the quickly evolving landscape, which could result in greater expectations of us and cause us to undertake costly initiatives to satisfy such new criteria. The increasing attention to corporate ESG initiatives could also result in increased investigations and litigation or threats thereof. If we are unable to satisfy such new criteria, investors may conclude that our ESG and sustainability practices are inadequate. If we fail or are perceived to have failed to achieve previously announced initiatives or goals or to accurately disclose our progress on such initiatives or goals, our reputation, business, financial condition and results of operations could be adversely impacted. Information technology failures and cyberattacks could affect us significantly. We rely on electronic systems and networks to communicate, control and manage our operations and prepare our financial management and reporting information. If we record inaccurate data or experience infrastructure outages, our ability to communicate and control and manage our business could be adversely affected. We face various security threats, including cybersecurity threats from third parties and unauthorized users to gain unauthorized access to sensitive information or to render data or systems unusable, threats to the security of our facilities, liquefaction facilities, and infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines, and threats from terrorist acts. Our network systems and storage and other business applications, and the systems and storage and other business applications maintained by our third-party providers, have been in the past, and may be in the future, subjected to attempts to gain unauthorized access to our network or information, malfeasance or other system disruptions. Our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities, liquefaction facilities, and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If security breaches were to occur, they could lead to losses of sensitive information, critical infrastructure or capabilities essential to our operations. If we were to experience an attack and our security measures failed, the potential consequences to our business and the communities in which we operate could be significant and could harm our reputation and lead to financial losses from remedial actions, loss of business or potential liability. Our insurance may be insufficient to cover losses that may occur to our property or result from our operations. Our current operations and future projects are subject to the inherent risks associated with construction of energy-related infrastructure, LNG, natural gas, power and maritime operations, shipping and transportation of hazardous substances, including explosions, pollution, release of toxic substances, fires, seismic events, hurricanes and other adverse weather conditions, acts of aggression or terrorism, and other risks or hazards, each of which could result in significant delays in commencement or interruptions of operations and/or result in damage to or destruction of the facilities, liquefaction facilities and assets or damage to persons and property. We do not, nor do we intend to, maintain insurance against all of these risks and losses. In particular, we do not generally carry business interruption insurance or political risk insurance with respect to political disruption in the countries in which we operate and that may in the future experience significant political volatility. Therefore, the occurrence of one or more significant events not fully insured or indemnified against could create significant liabilities and losses or delays to our development timelines, which could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects. Even if we choose to carry insurance for these events in the future, it may not be adequate to protect us from loss, which may include, for example, losses as a result of project delays or losses as a result of business interruption related to a political disruption. Any attempt to recover from loss from political disruption may be time-consuming and expensive, and the outcome may be uncertain. In addition, our insurance may be voidable by the insurers as a result of certain of our actions. Furthermore, we may be unable to procure adequate insurance coverage at commercially reasonable rates in the future. For example, environmental regulations have led in the past to increased costs for, and in the future may result in the lack of availability of, insurance against risks of environmental damage or pollution. Changes in the insurance markets attributable to terrorist attacks or political change may also make certain types of insurance more difficult or costly for us to obtain. Our success depends on key members of our management, the loss of any of whom could disrupt our business operations. We depend to a large extent on the services of our chief executive officer, Wesley R. Edens, some of our other executive officers and other key employees. Mr. Edens does not have an employment agreement with us. The loss of the services of Mr. Edens or one or more of our other key executives or employees could disrupt our operations and increase our exposure to the other risks described in this Item 1A. Risk Factors. We do not maintain key man insurance on Mr. Edens or any of our employees. As a result, we are not insured against any losses resulting from the death of our key employees. We may experience increased labor costs and regulation, and the unavailability of skilled workers or our failure to attract and retain qualified personnel, as well as our ability to comply with such labor laws, could adversely affect us. We are dependent upon the available labor pool of skilled employees for the construction and operation of our facilities and liquefaction facilities, as well as our FSRUs, FLNGs and LNG carriers. We compete with other energy companies and other employers to attract and retain qualified personnel with the technical skills and experience required to construct and operate our infrastructure and assets and to provide our customers with the highest quality service. In addition, the tightening of the labor market due to the shortage of skilled employees may affect our ability to hire and retain skilled employees, impair our operations and require us to pay increased wages. We are subject to labor laws in the jurisdictions in which we operate and hire our personnel, which can govern such matters as minimum wage, overtime, union relations, local content requirements and other working conditions. For example, Brazil and Indonesia, where some of our vessels operate, require we hire a certain portion of local personnel to crew our vessels. Any inability to attract and retain qualified local crew members could adversely affect our operations, business, results of operations and financial condition. Furthermore, should there be an outbreak of COVID-19 on our facilities or vessels, adequate staffing or crewing may not be available to fulfill the obligations under our contracts. Due to COVID-19, we could face (i) difficulty in finding healthy qualified replacement employees; (ii) local or international transport or quarantine restrictions limiting the ability to transfer infected employees from or to our facilities or vessels, and (iii) restrictions in availability of supplies needed for our projects due to disruptions to third-party suppliers or transportation alternatives. See General RisksWe are unable to predict the extent to which the global COVID-19 pandemic will negatively affect our operations, financial performance, nor our ability to achieve our strategic objectives. We are also unable to predict how this global pandemic may affect our customers and suppliers. A shortage in the labor pool of skilled workers or other general inflationary pressures or changes in applicable laws and regulations, could make it more difficult for us to attract and retain qualified personnel and could require an increase in the wage and benefits packages that we offer, thereby increasing our operating costs. Any increase in our operating costs could materially and adversely affect our business, financial condition, operating results, liquidity and prospects. Our business could be affected adversely by labor disputes, strikes or work stoppages. Some of our employees, particularly those in our Latin American operations, are represented by a labor union and are covered by collective bargaining agreements pursuant to applicable labor legislation. As a result, we are subject to the risk of labor disputes, strikes, work stoppages and other labor-relations matters. We could experience a disruption of our operations or higher ongoing labor costs, which could have a material adverse effect on our operating results and financial condition. Future negotiations with the unions or other certified bargaining representatives could divert management attention and disrupt operations, which may result in increased operating expenses and lower net income. Moreover, future agreements with unionized and non-unionized employees may be on terms that are note as attractive as our current agreements or comparable to agreements entered into by our competitors. Labor unions could also seek to organize some or all of our non-unionized workforce. Risks Related to the Jurisdictions in Which We Operate We are subject to the economic, political, social and other conditions in the jurisdictions in which we operate. Our projects are located in Jamaica and the United

States (including Puerto Rico), the Caribbean, Brazil, Mexico, Ireland, Nicaragua and other geographies and we have operations and derive revenues from additional markets. Furthermore, part of our strategy consists in seeking to expand our operations to other jurisdictions. As a result, our projects, operations, business, results of operations, financial condition and prospects are materially dependent upon economic, political, social and other conditions and developments in these jurisdictions. Some of these countries have experienced political, security, and social economic instability in the recent past and may experience instability in the future, including changes, sometimes frequent or marked, in energy policies or the personnel administering them, expropriation of property, cancellation or modification of contract rights, changes in laws and policies governing operations of foreign-based companies, unilateral renegotiation of contracts by governmental entities, redefinition of international boundaries or boundary disputes, foreign exchange restrictions or controls, currency fluctuations, royalty and tax increases and other risks arising out of governmental sovereignty over the areas in which our operations are conducted, as well as risks of loss due to acts of social unrest, terrorism, corruption and bribery. For example, in 2019, public demonstrations in Puerto Rico led to the governors resignation and the resulting political change interrupted the bidding process for the privatization of PREPAs transmission and distribution systems. While our operations to date have not been materially impacted by the demonstrations or political changes in Puerto Rico, any substantial disruption in our ability to perform our obligations under any agreements with PREPA could have a material adverse effect on our financial condition, results of operations and cash flows. Furthermore, we cannot predict how our relationship with PREPA could change given PREPAs privatization of its transmission, distribution and power generation system. PREPA may seek to find alternative power sources or purchase substantially less natural gas from us than what we currently expect to sell to PREPA. In addition, we cannot predict how local sentiment and support for our subsidiaries operations in Puerto Rico could change following the privatization of Puerto Ricos power generation systems. Should our operations face material local opposition, it could materially adversely affect our ability to perform our obligations under our contracts or could materially adversely impact PREPA or any applicable governmental counterpartys performance of its obligations to us. The governments in these jurisdictions differ widely with respect to structure, constitution and stability and some countries lack mature legal and regulatory systems. As our operations depend on governmental approval and regulatory decisions, we may be adversely affected by changes in the political structure or government representatives in each of the countries in which we operate. In addition, these jurisdictions, particularly emerging countries, are subject to risk of contagion from the economic, political and social developments in other emerging countries and markets. Furthermore, some of the regions in which we operate have been subject to significant levels of terrorist activity and social unrest, particularly in the shipping and maritime industries. Past political conflicts in certain of these regions have included attacks on vessels, mining of waterways and other efforts to disrupt shipping in the area. In addition to acts of terrorism, vessels trading in these and other regions have also been subject, in limited instances, to piracy. Tariffs, trade embargoes and other economic sanctions by the United States or other countries against countries in the Middle East, Southeast Asia, Africa or elsewhere as a result of terrorist attacks, hostilities or otherwise may limit trading activities with those countries. See Our Charterers may inadvertently violate applicable sanctions and/or call on ports located in, or engage in transactions with, countries that are subject to restrictions imposed by the U.S. or other governments, which could adversely affect its business. We do not, nor do we intend to, maintain insurance (such as business interruption insurance or terrorism) against all of these risks and losses. Any claims covered by insurance will be subject to deductibles, which may be significant, and we may not be fully reimbursed for all the costs related to any losses created by such risks. See Our insurance may be insufficient to cover losses that may occur to our property or result from our operations . As a result, the occurrence of any economic, political, social and other instability or adverse conditions or developments in the jurisdictions in which we operate, could have a material adverse effect on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects. Our financial condition and operating results may be adversely affected by foreign exchange fluctuations. While our consolidated financial statements are presented in U.S. dollars, we generate revenues and incur operating expenses and indebtedness in local currencies in the countries where we operate, such as, among others, the euro, the Mexican peso and the Brazilian real. The amount of our revenues denominated in a particular currency in a particular country typically varies from the amount of expenses or indebtedness incurred by our operations in that country given that certain costs may be incurred in a currency different from the local currency of that country, such as the U.S. dollar. Therefore, fluctuations in exchange rates used to translate other currencies into U.S. dollars could result in potential losses and reductions in our margins resulting from currency fluctuations, which may impact our reported consolidated financial condition, results of operations and cash flows from period to period. These fluctuations in exchange rates will also impact the value of our investments and the return on our investments. Additionally, some of the jurisdictions in which we operate may limit our ability to exchange local currency for U.S. dollars and elect to intervene by implementing exchange rate regimes, including sudden devaluations, periodic mini devaluations, exchange controls, dual exchange rate markets and a floating exchange rate system. There can be no assurance that non-U.S. currencies will not be subject to volatility and depreciation or that the current exchange rate policies affecting these currencies will remain the same. For example, the Mexican peso and the Brazilian real have experienced significant fluctuations relative to the U.S. dollar in the past. We may choose not to hedge, or we may not be effective in efforts to hedge, this foreign currency risk. See Risks Related to our BusinessAny use of hedging arrangements may adversely affect our future operating results or liquidity . Depreciation or volatility of these currencies against the U.S. dollar could cause counterparties to be unable to pay their contractual obligations under our agreements or to lose confidence in us and may cause our expenses to increase from time to time relative to our revenues as a result of fluctuations in exchange rates, which could affect the amount of net income that we report in future periods. Risks Related to Ownership of Our Class A Common Stock The market price and trading volume of our Class A common stock may be volatile, which could result in rapid and substantial losses for our stockholders. The market price of our Class A common stock may be highly volatile and could be subject to wide fluctuations. In addition, the trading volume in our Class A common stock may fluctuate and cause significant price variations to occur. If the market price of our Class A common stock declines significantly, you may be unable to resell your shares at or above your purchase price, if at all. The market price of our Class A common stock may fluctuate or decline significantly in the future. Some of the factors that could negatively affect our share price or result in fluctuations in the price or trading volume of our Class A common stock include: a shift in our investor base; our quarterly or annual earnings, or those of other comparable companies; actual or anticipated fluctuations in our operating results; changes in accounting standards, policies, guidance, interpretations or principles; announcements by us or our competitors of significant investments, acquisitions or dispositions; the failure of securities analysts to cover our Class A common stock; changes in earnings estimates by securities analysts or our ability to meet those estimates; the operating and share price performance of other comparable companies; overall market fluctuations; general economic conditions; and developments in the markets and market sectors in which we participate. Stock markets in the United States have experienced extreme price and volume fluctuations. Market fluctuations, as well as general political and economic conditions such as acts of terrorism, prolonged economic uncertainty, a recession or interest rate or currency rate fluctuations, could adversely affect the market price of our Class A common stock. We are a controlled company within the meaning of Nasdaq rules and, as a result, qualify for and intend to rely on exemptions from certain corporate governance requirements. Affiliates of certain entities controlled by Wesley R. Edens, Randal A. Nardone and affiliates of Fortress Investment Group LLC (Founder Entities), together with affiliates of Energy Transition Holdings LLC, hold a majority of the voting power of our stock. In addition, pursuant to the Shareholders Agreement, dated as of February 4, 2019, by and among the Company and the respective parties thereto (the Shareholders Agreement), the Founder Entities currently have the right to nominate a majority of the members of our Board of Directors. Furthermore, the Shareholders Agreement provides that the parties thereto will use their respective reasonable efforts (including voting or causing to be voted all of the Companys voting shares beneficially owned by each) to cause to be elected to the Board, and to cause to continue to be in office the director nominees selected by the Founder Entities. Affiliates of Energy Transition Holdings LLC are parties to the Shareholders Agreement and as of December 31, 2022 hold approximately 12.2% of the voting power of our stock. As a result, we are a controlled company within the meaning of the Nasdaq corporate governance standards. Under Nasdaq rules, a company of which more than 50% of the voting power for the election of directors is held by an individual, a group or another company is a controlled company and may elect not to comply with certain Nasdaq corporate governance requirements, including the requirements that: a majority of the board of directors consist of independent directors as defined under the rules of Nasdaq; the nominating and governance committee be composed entirely of independent directors with a written charter addressing the committees purpose and responsibilities; and the compensation committee be composed entirely of independent directors with a written charter addressing the committees purpose and responsibilities. These requirements will not apply to us as long as we remain a controlled company. A controlled company does not need its board of directors to have a majority of independent directors or to form independent compensation and nominating and governance committees. We intend to utilize some or all of these exemptions. Accordingly, our corporate governance may not afford the same protections as companies that are subject to all of the corporate governance requirements of Nasdaq. A small number of our original investors have the ability to direct the voting of a majority of our stock, and their interests may conflict with those of our other stockholders. As of December 31, 2022, affiliates of the Founder Entities own an aggregate of approximately 87,136,768 shares of Class A common stock, representing 41.7% of our voting power, and affiliates of Energy Transition Holdings LLC, party to the Shareholders Agreement, own an aggregate of approximately 25,559,846 shares of Class A common stock, representing approximately 12.2% of the voting power of our Class A common stock. The beneficial ownership of greater than 50% of our voting stock means affiliates of the Founder Entities and Energy Transition Holdings LLC are able to control matters requiring stockholder approval, including the election of directors, changes to our organizational documents and significant corporate transactions. This concentration of ownership makes it unlikely that any other holder or group of holders of our Class A common stock will be able to affect the way we are managed or the direction of our business. The interests of these parties with respect to matters potentially or actually involving or affecting us, such as future acquisitions, financings and other corporate opportunities and attempts to acquire us, may conflict with the interests of our other stockholders, including holders of the Class A common stock. Given this concentrated ownership, the affiliates of the Founder Entities and Energy Transition Holdings LLC would have to approve any potential acquisition of us. The existence of a significant stockholder may have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may deem to be in the best interests of our company. Moreover, the concentration of stock ownership with affiliates of the Founder Entities and Energy Transition Holdings LLC may adversely affect the trading price of our securities, including our Class A common stock, to the extent investors perceive a disadvantage in owning securities of a company with a significant stockholder. Furthermore, New Fortress Energy Holdings has assigned, pursuant to the terms of the Shareholders Agreement, to the Founder Entities, New

Fortress Energy Holdings right to designate a certain number of individuals to be nominated for election to our board of directors so long as its assignees collectively beneficially own at least 5% of the outstanding Class A common stock. The Shareholders Agreement provides that the parties to the Shareholders Agreement (including certain former members of New Fortress Energy Holdings) shall vote their stock in favor of such nominees. In addition, our Certificate of Incorporation provides the Founder Entities the right to approve certain material transactions so long as the Founder Entities and their affiliates collectively, directly or indirectly, own at least 30% of the outstanding Class A common stock. Our Certificate of Incorporation and By-Laws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our Class A common stock and could deprive our investors of the opportunity to receive a premium for their Class A common stock. Our Certificate of Incorporation and By-Laws authorize our board of directors to issue preferred stock without stockholder approval in one or more series, designate the number of stock constituting any series, and fix the rights, preferences, privileges and restrictions thereof, including dividend rights, voting rights, rights and terms of redemption, redemption price or prices and liquidation preferences of such series. If our board of directors elects to issue preferred stock, it could be more difficult for a third-party to acquire us. In addition, some provisions of our Certificate of Incorporation and By-Laws could make it more difficult for a third-party to acquire control of us, even if the change of control would be beneficial to our securityholders. These provisions include: dividing our board of directors into three classes of directors, with each class serving staggered three-year terms; providing that any vacancies may, except as otherwise required by law, or, if applicable, the rights of holders of a series of preferred stock, only be filled by the affirmative vote of a majority of directors then in office, even if less than a quorum (provided that vacancies that results from newly created directors requires a quorum); permitting special meetings of our stockholders to be called only by (i) the chairman of our board of directors, (ii) a majority of our board of directors, or (iii) a committee of our board of directors that has been duly designated by the board of directors and whose powers include the authority to call such meetings; prohibiting cumulative voting in the election of directors; establishing advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of the stockholders; and providing that the board of directors is expressly authorized to adopt, or to alter or repeal our certain provisions of our organizational documents to the extent permitted by law. Additionally, our Certificate of Incorporation provides that we have opted out of Section 203 of the Delaware General Corporation Law. However, our Certificate of Incorporation includes a similar provision, which, subject to certain exceptions, prohibits us from engaging in a business combination with an interested stockholder, unless the business combination is approved in a prescribed manner. Subject to certain exceptions, an interested stockholder means any person who, together with that persons affiliates and associates, owns 15% or more of our outstanding voting stock or an affiliate or associate of ours who owned 15% or more of our outstanding voting stock at any time within the previous three years, but shall not include any person who acquired such stock from the Founder Entities or Energy Transition Holdings LLC (except in the context of a public offering) or any person whose ownership of stock in excess of 15% of our outstanding voting stock is the result of any action taken solely by us. Our Certificate of Incorporation provides that the Founder Entities and Energy Transition Holdings LLC and any of their respective direct or indirect transferees, and any group as to which such persons are a party, do not constitute interested stockholders for purposes of this provision. Our By-Laws designate the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders ability to obtain a favorable judicial forum for disputes with us or our directors, officers, employees or agents. Our By-Laws provide that, unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware is, to the fullest extent permitted by applicable law, the sole and exclusive forum for (i) any derivative action or proceeding brought on our behalf, (ii) any action asserting a claim of breach of a fiduciary duty owed by any of our directors, officers, employees or agents to us or our stockholders, (iii) any action asserting a claim against us or any of our directors, officers or employees arising pursuant to any provision of our organizational documents or the Delaware General Corporation Law, or (iv) any action asserting a claim against us or any of our directors, officers or employees that is governed by the internal affairs doctrine, in each such case subject to such Court of Chancery having personal jurisdiction over the indispensable parties named as defendants therein. Any person or entity purchasing or otherwise acquiring any interest in our stock will be deemed to have notice of, and consented to, the provisions described in the preceding sentence. This choice of forum provision may limit a stockholders ability to bring a claim in a judicial forum that it considers more likely to be favorable for disputes with us or our directors, officers, employees or agents, which may discourage such lawsuits against us and such persons. Alternatively, if a court were to find these provisions of our organizational documents inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, financial condition, results of operations or prospects. The declaration and payment of dividends to holders of our Class A common stock is at the discretion of our board of directors and there can be no assurance that we will continue to pay dividends in amounts or on a basis consistent with prior distributions to our investors, if at all. The declaration and payment of dividends to holders of our Class A common stock will be at the discretion of our board of directors in accordance with applicable law after taking into account various factors, including actual results of operations, liquidity and financial condition, net cash provided by operating activities, restrictions imposed by applicable law, our taxable income, our operating expenses and other factors our board of directors deem relevant. There can be no assurance that we will continue to pay dividends in amounts or on a basis consistent with prior distributions to our investors, if at all. Because we are a holding company and have no direct operations, we will only be able to pay dividends from our available cash on hand and any funds we receive from our subsidiaries and our ability to receive distributions from our subsidiaries may be limited by the financing agreements to which they are subject. The incurrence or issuance of debt which ranks senior to our Class A common stock upon our liquidation and future issuances of equity or equity-related securities, which would dilute the holdings of our existing Class A common stockholders and may be senior to our Class A common stock for the purposes of making distributions, periodically or upon liquidation, may negatively affect the market price of our Class A common stock. We have incurred and may in the future incur or issue debt or issue equity or equity-related securities to finance our operations, acquisitions or investments. Upon our liquidation, lenders and holders of our debt and holders of our preferred stock (if any) would receive a distribution of our available assets before Class A common stockholders. Any future incurrence or issuance of debt would increase our interest cost and could adversely affect our results of operations and cash flows. We are not required to offer any additional equity securities to existing Class A common stockholders on a preemptive basis. Therefore, additional issuances of Class A common stock, directly or through convertible or exchangeable securities (including limited partnership interests in our operating partnership), warrants or options, will dilute the holdings of our existing Class A common stockholders and such issuances, or the perception of such issuances, may reduce the market price of our Class A common stock. Any preferred stock issued by us would likely have a preference on distribution payments, periodically or upon liquidation, which could eliminate or otherwise limit our ability to make distributions to Class A common stockholders. Because our decision to incur or issue debt or issue equity or equity-related securities in the future will depend on market conditions and other factors beyond our control, we cannot predict or estimate the amount, timing, nature or success of our future capital raising efforts. Thus, Class A common stockholders bear the risk that our future incurrence or issuance of debt or issuance of equity or equity-related securities will adversely affect the market price of our Class A common stock. We may issue preferred stock, the terms of which could adversely affect the voting power or value of our Class A common stock. Our Certificate of Incorporation and By-Laws authorize us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our Class A common stock in respect of dividends and distributions, as our board of directors may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our Class A common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the Class A common stock. Sales or issuances of our Class A common stock could adversely affect the market price of our Class A common stock. Sales of substantial amounts of our Class A common stock in the public market, or the perception that such sales might occur, could adversely affect the market price of our Class A common stock. The issuance of our Class A common stock in connection with property, portfolio or business acquisitions or the exercise of outstanding options or otherwise could also have an adverse effect on the market price of our Class A common stock. An active, liquid and orderly trading market for our Class A common stock may not be maintained and the price of our Class A common stock may fluctuate significantly. Prior to January 2019, there was no public market for our Class A common stock. An active, liquid and orderly trading market for our Class A common stock may not be maintained. Active, liquid and orderly trading markets usually result in less price volatility and more efficiency in carrying out investors purchase and sale orders. The market price of our Class A common stock could vary significantly as a result of a number of factors, some of which are beyond our control. In the event of a drop in the market price of our Class A common stock, you could lose a substantial part or all of your investment in our Class A common stock. General Risks We are a holding company and our operational and consolidated financial results are dependent on the results of our subsidiaries, affiliates, joint ventures and special purpose entities in which we invest. We conduct our business mainly through our operating subsidiaries and affiliates, including joint ventures and other special purpose entities, which are created specifically to participate in projects or manage a specific asset. Our ability to meet our financial obligations is therefore related in part to the cash flow and earnings of our subsidiaries and affiliates and the ability or willingness of these entities to make distributions or other transfers of earnings to us in the form of dividends, loans or other advances and payments, which are governed by various shareholder agreements, joint venture financing and operating arrangements. In addition, some of our operating subsidiaries, joint venture and special purpose entities are subject to restrictive covenants related to their indebtedness, including restrictions on dividend distributions. Any additional debt or other financing could include similar restrictions, which would limit their ability to make distributions or other transfers of earnings to us in the form of dividends, loans or other advances and payments. Similarly, we may fail to realize anticipated benefits of any joint venture or similar arrangement, which could adversely affect our financial condition and results of operation. We may engage in mergers, sales and acquisitions, divestments, reorganizations or similar transactions related to our businesses or assets in the future and we may fail to successfully complete such transaction or to realize the expected value. In furtherance of our business strategy, we may engage in mergers, purchases or sales, divestments, reorganizations or other similar transactions related to our businesses or assets in the future. Any such transactions may be subject to significant risks and contingencies, including the risk of integration, valuation and successful implementation, and we may not be able to realize the benefits of any such transactions. We may also engage in sales of our assets or sale and leaseback transactions that seek to monetize our assets and there is no guarantee that such sales of assets will be executed at the prices we desire or higher than the values we currently carry these assets at on our balance sheet. We do not know if we will be able to successfully complete any such transactions or whether we will be able to retain key personnel, suppliers or distributors. Our ability to successfully implement our strategy through such transactions depends upon our ability to identify, negotiate and complete suitable transactions and to obtain the required financing on terms acceptable to us. These efforts could be expensive and time consuming, disrupt our ongoing business and distract management. If we are unable to successfully complete our transactions, our business, financial condition, results of operations and prospects could be materially adversely affected. We are unable to predict the extent to which the global pandemics and health crisis, such as the COVID-19 pandemic, will negatively affect our operations, financial performance, nor our ability to achieve our strategic objectives. We are also unable to predict how this global pandemic may affect our customers and suppliers. The COVID-19 pandemic has caused, and is expected to continue to cause, economic disruptions in various regions, disruptions in global supply chains, significant volatility and disruption of financial markets and in the price of oil and other commodities. In addition, the pandemic has made, and any future global health crisis or pandemic could make, travel and commercial activity significantly more cumbersome and less efficient compared to pre-pandemic conditions. Because the severity, magnitude and duration of any such crisis or pandemic and its economic consequences are uncertain, rapidly-changing and difficult to predict, its impact on our operations and financial performance, as well as its impact on our ability to successfully execute our business strategies and initiatives, remains or could be uncertain and difficult to predict. Further, the ultimate impact of any such pandemic or crisis on our operations and financial performance depends on many factors that are not within our control, including, but not limited, to: governmental, business and individuals actions that have been and continue to be taken in response to the COVID-19 pandemic (including restrictions on travel and transport and workforce pressures); the impact of such pandemic or crisis and actions taken in response on global and regional economies, travel, and economic activity; the availability of federal, state, local or non-U.S. funding programs, as well as other monetary and financial policies enacted by governments (including monetary policy, taxation, exchange controls, interest rates, regulation of banking and financial services and other industries, government budgeting and public sector financing); the duration and severity of resurgences of any variants; general economic uncertainty in key global markets and financial market volatility; global economic conditions and levels of economic growth; and the pace of recovery when the pandemic or crisis subsides. Our operations, financial performance and financial condition have been subjected to the COVID-19 pandemic and could be subjected to a number of operational financial risks in any such future pandemic or crisis. Although the services we provide are generally deemed essential, we may face negative impacts from increased operational challenges based on the need to protect employee health and safety, workplace disruptions and restrictions on the movement of people including our employees and subcontractors, and disruptions to supply chains related to raw materials and goods both at our own facilities, liquefaction facilities and at customers and suppliers. We may also experience a lower demand for natural gas at our existing customers and a decrease in interest from potential customers as a result of the pandemics impact on the operations and financial condition of our customers and potential customers, as well as the price of available fuel options, including oil-based fuels as well as strains the pandemic places on the capacity of potential customers to evaluate purchasing our goods and services. We may experience customer requests for potential payment deferrals or other contract modifications and delays of potential or ongoing construction projects due to government guidance or customer requests. Conditions in the financial and credit markets may limit the availability of funding and pose heightened risks to future financings we may require. These and other factors we cannot anticipate could adversely affect our business, financial position and results of operations. It is possible that the longer this period of economic and global supply chain and disruption continues, the greater the uncertainty will be regarding the possible adverse impact on our business operations, financial performance and results of operations. A change in tax laws in any country in which we operate could adversely affect us. Tax laws, regulations and treaties are highly complex and subject to interpretation. Consequently, we are subject to changing laws, treaties and regulations in and between the countries in which we operate. Our tax expense is based on our interpretation of the tax laws in effect at the time the expense was incurred. A change in tax laws, regulations, or treaties, or in the interpretation thereof, could result in a materially higher tax expense or a higher effective tax rate on our earnings. Our after-tax profitability could be affected by numerous factors, including the availability of tax credits, exemptions and other benefits to reduce our tax liabilities, changes in the relative amount of our earnings subject to tax in the various jurisdictions in which we operate, the potential expansion of our business into or otherwise becoming subject to tax in additional jurisdictions, changes to our existing businesses and operations, the extent of our intercompany transactions and the extent to which taxing authorities in the relevant jurisdictions respect those intercompany transactions. Our after-tax profitability may also be affected by changes in the relevant tax laws and tax rates, regulations, administrative practices and principles, judicial decisions, and interpretations, in each case, possibly with retroactive effect. We are and may be involved in legal proceedings and may experience unfavorable outcomes. We are and may in the future be subject to material legal proceedings in the course of our business or otherwise, including, but not limited to, actions relating to contract disputes, business practices, intellectual property, real estate and leases, and other commercial, tax, regulatory and permitting matters. Such legal proceedings may involve claims for substantial amounts of money or for other relief or might necessitate changes to our business or operations, and the defense of such actions may be both time-consuming and expensive. Moreover, the process of litigating requires substantial time, which may distract our management. Even if we are successful, any litigation may be costly, and may approximate the cost of damages sought. These actions could also expose us to adverse publicity, which might adversely affect our reputation and therefore, our results of operations. Further, if any such proceedings were to result in an unfavorable outcome, it could have an adverse effect on our business, financial position and results of operations. If we fail to develop or maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential stockholders could lose confidence in our financial reporting, which would harm our business and the trading price of our Class A common stock. Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a publicly traded company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes-Oxley Act. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our Class A common stock. The requirements of being a public company, including compliance with the reporting requirements of the Securities Exchange Act of 1934, as amended (the Exchange Act), and the requirements of the Sarbanes-Oxley Act, may strain our resources, increase costs and distract management, and we may be unable to comply with these requirements in a timely or cost-effective manner. As a public company with stock listed on Nasdaq, we are subject to an extensive body of regulations, including certain provisions of the Sarbanes-Oxley Act, the Dodd-Frank Act, regulations of the SEC and Nasdaq requirements. Compliance with these rules and regulations increases our legal, accounting, compliance and other expenses. For example, as a result of becoming a public company, we added independent directors and created additional board committees. We entered into an administrative services agreement with FIG LLC, an affiliate of Fortress Investment Group (which currently employs Messrs. Edens, our chief executive officer and chairman of our Board of Directors, and Nardone, one of our Directors), in connection with the IPO, pursuant to which FIG LLC provides us with certain back-office services and charges us for selling, general and administrative expenses incurred to provide these services. In addition, we may incur additional costs associated with our public company reporting requirements and maintaining directors and officers liability insurance. It is possible that our actual incremental costs of being a publicly traded company will be higher than we currently estimate, and the incremental costs may have a material adverse effect on our business, prospects, financial condition, results of operations and cash flows. If securities or industry analysts do not publish research or reports about our business, if they adversely change their recommendations regarding our Class A common stock or if our operating results do not meet their expectations, our share price could decline. The trading market for our

Ticker: NFE, Sector: Utilities, Filed At: 2023-03-01T13:46:49-05:00

Class A common stock will be influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of our company or fail to publish reports on us regularly, we could lose viability in the financial markets, which in turn could cause our share price or trading volume to decline.

Ticker: NJR, Sector: Utilities, Filed At: 2023-02-09T19:12:06-05:00

Ticker: NJR, Sector: Utilities, Filed At: 2023-11-21T16:28:09-05:00

ITEM 1. BUSINESS ##TABLE_START ORGANIZATIONAL STRUCTURE ##TABLE_ENDNew Jersey Resources Corporation is a New Jersey corporation and a diversified energy services holding company whose principal business is the distribution of natural gas through a regulated utility, investing in and operating clean energy projects and natural gas storage and transportation assets, and providing other retail and wholesale energy services to customers. We are an exempt holding company under Section 1263 of the Energy Policy Act of 2005. Our primary subsidiaries include the following: New Jersey Natural Gas Company provides regulated natural gas utility service to approximately 576,000 residential and commercial customers throughout Burlington, Middlesex, Monmouth, Morris, Ocean and Sussex counties in New Jersey and participates in the off-system sales and capacity release markets. NJNG, a local natural gas distribution company, is regulated by the BPU and comprises the Companys Natural Gas Distribution segment. NJR Clean Energy Ventures Corporation includes the results of operations and assets related to the Companys unregulated capital investments in clean energy projects, including commercial and residential solar projects. NJRCEV comprises the Companys Clean Energy Ventures segment. NJR Energy Services Company, LLC maintains and transacts around a portfolio of physical assets consisting of natural gas transportation and storage contracts in the U.S. and Canada. NJRES also provides unregulated wholesale energy management services to other energy companies and natural gas producers. NJRES comprises our Energy Services segment. NJR Midstream Holdings Corporation, which comprises the Storage and Transportation segment, invests in energy-related ventures through its subsidiaries: NJR Midstream Company, which includes our wholly-owned subsidiaries of Leaf River, located in southeastern Mississippi, and Adelphia, located in eastern Pennsylvania, which are subject to FERC regulation, along with our 20% ownership interest in PennEast, which ceased operations in fiscal 2022; and NJR Steckman Ridge Storage Company, which holds our 50% combined ownership interest in Steckman Ridge, located in Pennsylvania. See Note 7. Investments in Equity Investees for more information on Steckman Ridge and PennEast. NJR Home Services Company provides heating, ventilation and cooling service, sales and installation of appliances to approximately 101,500 service contract customers, as well as solar installation projects, and is the primary contributor to Home Services and Other operations. Page 4 New Jersey Resources Corporation Part I ITEM 1. BUSINESS (Continued) ##TABLE_START REPORTING SEGMENTS ##TABLE_ENDWe operate within four reporting segments: Natural Gas Distribution, Clean Energy Ventures, Energy Services and Storage and Transportation. NJNG consists of regulated natural gas services, off-system sales, capacity and storage management operations. ES consists of unregulated wholesale and retail energy operations, as well as energy management services. CEV consists of capital investments in clean energy projects. ST consists of operations and investments in the natural gas storage and transportation market, such as natural gas storage and transportation facilities. Net income by reporting segment and other business operations for the fiscal years ended September 30, are as follows: ST incurred a net loss of $67.8M during fiscal 2021, which is not shown clearly in the above graph. Assets composition by reporting segment and other business operations at September 30, are as follows: ##TABLE_START 2023 2022 ##TABLE_ENDPage 5 New Jersey Resources Corporation Part I ITEM 1. BUSINESS (Continued) Management uses NFE, a non-GAAP financial measure, when evaluating its operating results. NFE is a measure of the earnings based on eliminating timing differences surrounding the recognition of certain gains or losses to effectively match the earnings effects of the economic hedges with the physical sale of natural gas and, therefore, eliminates the impact of volatility to GAAP earnings associated with the derivative instruments. ES economically hedges its natural gas inventory with financial derivative instruments and calculates the related tax effect based on the statutory rate. NFE also excludes certain transactions associated with equity method investments, including impairment charges, which are non-cash charges, and return of capital in excess of the carrying value of our investment. These are considered unusual in nature and occur infrequently and are not indicative of the Companys performance for its ongoing operations. Included in the tax effects are current and deferred income tax expense corresponding with the components of NFE. Non-GAAP financial measures are not in accordance with, or an alternative to, GAAP, and should be considered in addition to, and not as a substitute for, the comparable GAAP measure. The following is a reconciliation of consolidated net income, the most directly comparable GAAP measure, to NFE for the fiscal years ended September 30: ##TABLE_START (Thousands) 2023 2022 2021 Net income $ 264,724 $ 274,922 $ 117,890 Add: Unrealized (gain) loss on derivative instruments and related transactions (38,081) (59,906) 54,203 Tax effect 9,050 14,248 (12,887) Effects of economic hedging related to natural gas inventory 34,699 19,939 (42,405) Tax effect (8,246) (4,738) 10,078 (Gain on) impairment of equity method investment (300) (5,521) 92,000 Tax effect (19) 1,377 (11,167) NFE $ 261,827 $ 240,321 $ 207,712 Basic earnings per share $ 2.73 $ 2.86 $ 1.23 Add: Unrealized (gain) loss on derivative instruments and related transactions (0.39) (0.62) 0.56 Tax effect 0.09 0.15 (0.13) Effects of economic hedging related to natural gas inventory 0.36 0.21 (0.44) Tax effect (0.09) (0.05) 0.10 (Gain on) impairment of equity method investment (0.06) 0.96 Tax effect 0.01 (0.12) Basic NFE per share $ 2.70 $ 2.50 $ 2.16 ##TABLE_ENDNFE by reporting segment and other business operations for the fiscal years ended September 30, are as follows: Page 6 New Jersey Resources Corporation Part I ITEM 1. BUSINESS (Continued) Natural Gas Distribution General NJNG consists of regulated utility operations that provide natural gas service to approximately 576,000 customers. NJNGs service territory includes Burlington, Middlesex, Monmouth, Morris, Ocean and Sussex counties in New Jersey. It encompasses 1,516 square miles, covering 110 municipalities with an estimated population of 1.5 million people. It is primarily suburban, highlighted by approximately 100 miles of New Jersey coastline. It is in close proximity to New York City, Philadelphia and the metropolitan areas of northern New Jersey, and is accessible through a network of major roadways and mass transportation. NJNGs business is subject to various risks, such as those associated with adverse economic conditions, which can negatively impact customer growth and operating and financing costs; fluctuations in commodity prices, which can impact customer usage; certain regulatory actions; and environmental remediation. It is often difficult to predict the impact of trends associated with these risks. NJNG employs strategies to pursue customer conversions from other fuel sources and monitor new construction markets through contact with developers, utilize incentive programs through BPU-approved mechanisms to reduce natural gas costs, pursue rate and other regulatory strategies designed to stabilize and decouple gross margin, and work actively with consultants and the NJDEP to manage expectations related to its obligations associated with its former MGP sites. Operating Revenues/Throughput For the fiscal years ended September 30, operating revenues and throughput by customer class for NJNG are as follows: ##TABLE_START 2023 2022 2021 ($ in thousands) Operating Revenue Bcf Operating Revenue Bcf Operating Revenue Bcf Residential $ 643,756 43.4 $ 598,433 45.5 $ 484,407 46.2 Commercial and other 137,343 8.4 140,727 8.7 103,341 8.6 Firm transportation 79,537 12.1 80,915 13.0 69,353 13.7 Total residential and commercial 860,636 63.9 820,075 67.2 657,101 68.5 Interruptible/off-tariff agreements/other 9,996 29.5 9,740 32.4 7,239 22.9 Total system 870,632 93.4 829,815 99.6 664,340 91.4 BGSS incentive programs (1) 142,001

34.9 298,952 44.5 67,456 20.8 Total $ 1,012,633 128.3 $ 1,128,767 144.1 $ 731,796 112.2 ##TABLE_END(1) Does not include 37.7, 50.7 and 80.5 Bcf for the capacity release program and related amounts of approximately $0.9M, $0.7M and $3.1M, which are recorded as a reduction of natural gas purchases on the Consolidated Statements of Operations during fiscal 2023, 2022 and 2021, respectively. NJNG added 8,800 and 7,808 new customers during fiscal 2023 and 2022, respectively. NJNG expects its annual customer growth rate to be approximately 1.9%. This anticipated customer growth represents approximately $8.5M in new annual Utility Gross Margin, a non-GAAP financial measure, as calculated under NJNGs current CIP tariff. For a reconciliation of Utility Gross Margin to gross margin see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations-Natural Gas Distribution . In fiscal 2023, no single customer represented more than 10% of consolidated operating revenues. Seasonality of Natural Gas Revenues Therm sales are significantly affected by weather conditions, with customer demand being greatest during the winter months when natural gas is used for heating purposes. The relative measurement of the impact of weather is in Degree-days. Degree-day data is used to estimate amounts of energy required to maintain comfortable indoor temperature levels based on each days average temperature. Each degree of temperature below 65 degrees Fahrenheit is counted as one heating Degree-day. Normal heating Degree-days are based on a 20-year average, calculated based on three reference areas representative of NJNGs service territory. CIP, a mechanism authorized by the BPU, stabilizes NJNGs Utility Gross Margin, regardless of variations in weather. In addition, CIP decouples the link between Utility Gross Margin and customer usage, allowing NJNG to promote energy conservation measures. Recovery of Utility Gross Margin is subject to additional conditions, including an earnings test, a revenue test and an evaluation of BGSS-related savings achieved over a 12-month period. The BPU approved the continuation of the CIP program with no expiration date. Page 7 New Jersey Resources Corporation Part I ITEM 1. BUSINESS (Continued) Concurrent with its annual BGSS filing, NJNG files for an annual review of its CIP, at which time it can request rate changes, as appropriate. For additional information regarding CIP, including rate actions and impact to margin, see Note 4. Regulation in the accompanying Consolidated Financial Statements and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations-Natural Gas Distribution . Natural Gas Supply Firm Natural Gas Supplies In fiscal 2023, NJNG purchased natural gas from approximately 58 suppliers under contracts ranging from one day to seven months and purchased over 10% of its natural gas from two suppliers. NJNG believes the loss of either of these suppliers would not have a material adverse impact on its results of operations, financial position or cash flows, as an adequate number of alternative suppliers exist. NJNG believes that its supply strategy should adequately meet its expected firm load for the upcoming winter season. Firm Transportation and Storage Capacity NJNG maintains agreements for firm transportation and storage capacity with several interstate pipeline companies to take delivery of firm natural gas supplies, which ensures the ability to reliably service its customers. NJNG receives natural gas at 11 citygate stations located in Burlington, Middlesex, Morris and Passaic counties in New Jersey. The pipeline companies that provide firm transportation service to NJNGs citygate stations, the maximum daily deliverability of that capacity and the contract expiration dates are as follows: ##TABLE_START Pipeline Dths (1) Expiration Transcontinental Gas Pipe Line Corp. 332,531 Various dates between 2024 and 2033 Texas Eastern Transmission, L.P. 383,588 Various dates between 2024 and 2025 Columbia Gas Transmission Corp. 50,000 Various dates between 2024 and 2030 Tennessee Gas Pipeline Co. 25,166 Various dates between 2028 and 2029 Algonquin Gas Transmission 12,000 2025 Total 803,285 ##TABLE_END(1) Numbers are shown net of any capacity release contracted amounts. Eastern Gas Transmission and Storage, Inc., Tennessee Gas Pipeline Co., Transcontinental Gas Pipe Line Corp. and Adelphia provide NJNG upstream firm contract transportation service and supply pipelines included in the table above. In addition, NJNG has storage contracts that provide an additional 102,941 Dths of maximum daily deliverability to NJNGs citygate stations from storage fields in its Northeast market area. The storage suppliers, the maximum daily deliverability of that storage capacity and the contract expiration dates are as follows: ##TABLE_START Pipeline Dths Expiration Texas Eastern Transmission, L.P. 94,557 2025 Transcontinental Gas Pipe Line Corp. 8,384 2028 Total 102,941 ##TABLE_ENDNJNG also has upstream storage contracts. The maximum daily deliverability and contract expiration dates are as follows: ##TABLE_START Company Dths Expiration Eastern Gas Transmission and Storage 286,829 Various dates between 2024 and 2026 Steckman Ridge, L.P. 38,000 2025 Stagecoach Pipeline Storage Company LLC 25,337 2028 Total 350,166 ##TABLE_ENDNJNG utilizes its transportation contracts to transport natural gas to NJNGs citygates from the Eastern Gas Transmission and Storage, Inc., Steckman Ridge and Stagecoach Pipeline Storage Company LLC storage fields. NJNG has sufficient firm transportation, storage and supply capacity to fully meet its customer demand for natural gas within its service territory. Citygate Supplies from ES NJNG has one AMA with ES. NJNG and ES have an agreement where NJNG releases 7,150 Dths/day of TETCO capacity, 2,200 Dths/day of Eastern Gas Transmission and Storage, Inc. capacity, 10,728 Dths/day of Tennessee Gas Pipeline Page 8 New Jersey Resources Corporation Part I ITEM 1. BUSINESS (Continued) capacity and 1.6 million Dths of Stagecoach Pipeline Storage Company LLC storage capacity to ES through March 31, 2024. NJNG can call upon a supply of up to 14,300 Dths/day delivered to NJNGs TETCO citygate through March 31, 2024. ES manages the storage inventory and NJNG can call on that storage supply as needed at NJNGs Tennessee citygate or storage point. Peaking Supply To manage its winter peak day demand, NJNG maintains two LNG facilities with a combined deliverability of approximately 170,000 Dths/day, which represents approximately 18% of its estimated peak day sendout. NJNGs liquefaction facility allows NJNG to convert natural gas into LNG to fill NJNGs existing LNG storage tanks. See Item 2. Properties-Natural Gas

Distribution for additional information regarding the LNG storage facilities. Basic Gas Supply Service BGSS is a BPU-approved clause designed to allow for the recovery of natural gas commodity costs on an annual basis. The clause requires all New Jersey natural gas utilities to make an annual filing by each June 1 for review of BGSS rates and to request a potential rate change effective the following October 1. The BGSS also allows each natural gas utility to provisionally increase residential and small commercial customer BGSS rates on December 1 and February 1 for up to a 5% increase to the average residential heat customers bill on a self-implementing basis with proper notice. Such increases are subject to subsequent BPU review and final approval. In addition to making periodic rate adjustments to reflect changes in commodity prices, NJNG is also permitted to refund or credit back a portion of the commodity costs to customers when the natural gas commodity costs decrease in comparison to amounts projected or to amounts previously collected from customers. Decreases in the BGSS rate and BGSS refunds can be implemented with five days notice to the BPU. Rate changes, as well as other regulatory actions related to BGSS, are discussed further in Note 4. Regulation in the accompanying Consolidated Financial Statements. Wholesale natural gas prices are, by their nature, volatile. NJNG mitigates the impact of volatile price changes on customers through the use of financial derivative instruments, which are part of its storage incentive program and its BGSS clause. Future Natural Gas Supplies NJNG expects to meet the natural gas requirements for existing and projected firm customers. If NJNGs long-term natural gas requirements change, NJNG expects to renegotiate and restructure its contract portfolio to better match the changing needs of its customers and changing natural gas supply landscape. Regulation and Rates State NJNG is subject to the jurisdiction of the BPU with respect to a wide range of matters such as base rates and regulatory rider rates, the issuance of securities, the safety and adequacy of service, the manner of keeping its accounts and records, the sufficiency of natural gas supply, pipeline safety, environmental issues, compliance with affiliate standards and the sale or encumbrance of its properties. See Note 4. Regulation in the accompanying Consolidated Financial Statements for additional information regarding NJNGs rate proceedings. Federal FERC regulates rates charged by interstate pipeline companies for the transportation and storage of natural gas. This may affect NJNGs agreements with several interstate pipeline companies for the purchase of such services. Costs associated with these services are currently recoverable through the BGSS. Competition Although its franchises are nonexclusive, NJNG is not currently subject to competition from other natural gas distribution utilities with regard to the transportation of natural gas in its service territory. Due to significant distances between NJNGs current large industrial customers and the nearest interstate natural gas pipelines, as well as the availability of its transportation tariff, NJNG currently does not believe it has significant exposure to the risk that its distribution system will be bypassed. Competition does exist from suppliers of oil, electricity and propane. At the present time, however, natural gas is used in over 95% of new construction due to its efficiency, reliability and price advantage. Natural gas prices are a function of market supply and demand.

Although NJNG believes natural gas will remain competitive with alternate fuels, no assurance can be given in this regard. Page 9 New Jersey Resources Corporation Part I ITEM 1. BUSINESS (Continued) The BPU, within the framework of the EDECA, fully opened NJNGs residential markets to competition, including third-party suppliers, and restructured rates to segregate its BGSS and delivery (i.e., transportation) prices. New Jerseys natural gas utilities must provide BGSS in the absence of a third-party supplier. On September 30, 2023, NJNG had 15,457 residential and 8,033 commercial and industrial customers utilizing the transportation service. Clean Energy Ventures CEV invests in, owns and operates clean energy projects, including commercial and residential solar installations located in six states including New Jersey, Rhode Island, New York, Connecticut, Michigan and Indiana. As of September 30, 2023, CEV has approximately 468.8 MW of solar capacity in service, including a combination of residential and commercial net-metered and grid-connected solar systems. As part of its solar investment portfolio, CEV operates a residential and small commercial solar program, The Sunlight Advantage, that provides qualifying homeowners and small business owners with the opportunity to have a solar system installed at their home or place of business with no installation or maintenance expenses. CEV owns, operates and maintains the system over the life of the lease in exchange for monthly lease payments. The program is operated by CEV using qualified contracting partners in addition to strategic suppliers for material standardization and sourcing. The residential solar lease and PPA market is highly competitive, with a large number of companies operating in New Jersey. CEV competes on price, quality and brand reputation, leveraging its partner network and customer referrals. CEVs commercial solar projects are sourced through various channels and include both net-metered and grid-connected systems. Net-metered projects involve the sale of energy to a host and grid-connected systems into the wholesale energy markets. Project construction is competitively sourced through third parties. New Jersey has the eighth largest solar market in the U.S., according to the Solar Energy Industries Association, with a large number of firms competing in all facets of the market including development, financing and construction. Our solar systems are registered and certified with the BPUs Office of Clean Energy and qualified to produce RECs. One REC is created for every MWh of electricity produced by a solar generator. CEV sells SRECs generated to a variety of counterparties, including electric load-serving entities that serve electric customers in New Jersey and are required to comply with the solar carve-out of the Renewable Portfolio Standard, a regulation that requires the increased production of energy from renewable energy sources. Solar projects are also currently eligible for federal ITCs in the year that they are placed into service. In December 2019, the BPU established the TREC as the interim program successor to the SREC program. TRECs provide a fixed compensation base multiplied by an assigned project factor in order to determine their value. The project factor is determined by the type and location of the project, as defined. All TRECs generated are required to be purchased monthly by a TREC program administrator as appointed by the BPU. In July 2021, the BPU approved the first portion of the solar successor program for net-metered projects under 5 MWs. The new program opened to new applications on August 28, 2021. Incentives are structured as a 15-year fixed incentive ranging from $85 to $130/MWh depending on market segment, project siting and size. The second phase of the successor program, the CSI Program, was established on December 7, 2022. The CSI program was designed to encourage grid scale solar generation with a goal of incentivizing development of at least 300 MW of solar annually until 2026. Solicitations take place annually, and all projects that meet pre-qualification requirements will compete on price only. The next solicitation will open on November 27, 2023, and will close to bids on February 29, 2024. CEV is subject to various risks including those associated with adverse federal and state legislation and regulatory policies, electric grid connection, supply chain and/or construction delays that can impact the timing or eligibility of tax incentives, technological changes and the future market of RECs. See Item 1A. Risk Factors for additional information regarding these risks. Energy Services ES consists of unregulated wholesale and retail natural gas operations and provides producer and asset management services to a diverse customer base across North America. ES has acquired contractual rights to natural gas transportation and storage assets it utilizes to implement its strategic and opportunistic market strategies. The rights to these assets were acquired in anticipation of delivering natural gas, performing asset management services for customers or identifying strategic opportunities that exist in or between the market areas that it serves. These opportunities are driven by price differentials between market locations and/or time periods. ESs activities are conducted in the market areas in which it has strong expertise, including the U.S. and Canada. ES differentiates itself in the marketplace based on price, reliability and quality of service. Its competitors include wholesale marketing and trading companies, utilities, natural gas producers and financial institutions. ESs portfolio of customers includes regulated natural gas distribution companies, industrial companies, electric generators, natural gas/liquids processors, retail aggregators, wholesale marketers and natural gas producers. Page 10 New Jersey Resources Corporation Part I ITEM 1. BUSINESS (Continued) While focusing on maintaining a low-risk operating and counterparty credit profile, ESs activities specifically consist of the following elements: Providing natural gas portfolio management services to nonaffiliated and our affiliated natural gas utility, electric generation facilities and natural gas producers; Managing strategies for new and existing natural gas transportation and storage assets to capture value from changes in price due to location or timing differences as a means to generate Financial Margin; Managing transactional logistics to minimize the cost of natural gas delivery to customers while maintaining security of supply. Transactions utilize the most optimal and advantageous natural gas supply transportation routing available within its contractual asset portfolio and various market areas; and Managing economic hedging programs that are designed to mitigate the impact of changes in market prices on Financial Margin generated on its natural gas transportation and storage commitments. In an effort to deliver more predictable earnings contributions, reduce earnings volatility and monetize the value of its natural gas transportation portfolio, ES entered into a series of AMAs in December 2020 with an investment grade public utility to release pipeline capacity associated with certain natural gas transportation contracts. The AMAs include a series of initial and permanent releases, which commenced in November 2021. NJR will receive a total of approximately $260M in cash from fiscal 2022 through fiscal 2024 and $34M per year from fiscal 2025 through fiscal 2031 under the agreements. During fiscal 2023, ES did not purchase over 10% of its natural gas from any one supplier. Transportation and Natural Gas Storage Transactions ES focuses on creating value from the use of its physical assets, which are typically amassed through contractual rights to natural gas transportation and storage capacity. These assets become more valuable when favorable price changes occur that impact the value between or within market areas and across time periods. On a forward basis, ES may hedge these price differentials through the use of financial instruments. In addition, ES may seek to optimize these assets on a daily basis, as market conditions warrant, by evaluating natural gas supply and transportation availability within its portfolio. This enables ES to capture geographic pricing differences across various regions, as delivered natural gas prices may change favorably as a result of market conditions. ES may, for example, initiate positions when intrinsic Financial Margin is present, and then enhance that Financial Margin as prices change across regions or time periods. ES also engages in park and loan transactions with storage and pipeline operators, where ES will either borrow (receive a loan of) natural gas with an obligation to repay the storage or pipeline operator at a later date or park natural gas with an obligation to withdraw at a later date. In these cases, ES evaluates the economics of the transaction to determine if it can capture pricing differentials in the marketplace and generate Financial Margin. ES evaluates deal attributes such as fixed fees and calendar-spread value from deal inception until volumes are scheduled to be returned and/or repaid, as well as the time value of money. If this evaluation demonstrates that Financial Margin exists, ES may enter into the transaction and hedge with natural gas futures contracts, thereby locking in Financial Margin. ES maintains inventory balances to satisfy existing or anticipated sales of natural gas to its counterparties and/or to create additional value, as described above. During fiscal 2023 and 2022, ES managed and sold 150.4 Bcf and 231.1 Bcf of natural gas, respectively. In addition, as of September 30, 2023 and 2022, ES had 14.6 Bcf or $24.5M of natural gas in storage and 10.8 Bcf or $82.5M of natural gas in storage, respectively. Weather/Seasonality ES activities are typically seasonal in nature as a result of changes in the supply and demand for natural gas. Demand for natural gas is generally higher during the winter months when there may also be supply constraints; however, during periods of milder temperatures, demand can decrease. In addition, demand for natural gas can also be high during periods of extreme heat in the summer months, resulting from the need for additional natural gas supply for natural gas-fired electric generation facilities. Accordingly, ES can be subject to variations in earnings and working capital throughout the year as a result of changes in weather.

Volatility ESs activities are also subject to price volatility or supply/demand dynamics within its North American wholesale markets, including in the Northeastern, Appalachian, Mid-Continent and Southeast regions. Changes in natural gas supply can affect capacity values and ESs Financial Margin, which, as described below, is generated from the optimization of transportation and storage assets. With its focus on risk management, ES continues to diversify its revenue stream by identifying new growth opportunities in producer and asset management services. ES monitors changing market dynamics and strategically adjusts its portfolio of transportation and storage assets, which currently includes an average of approximately 21.8 Bcf of firm storage and 0.6 Bcf of firm transportation capacity. Financial Margin To economically hedge the commodity price risk associated with its existing and anticipated commitments for the purchase and sale of natural gas, ES enters into a variety of derivative instruments including, but not limited to, futures contracts, physical forward contracts, financial swaps and options. These derivative instruments are accounted for at fair value with changes in fair value recognized in earnings as they occur. ES views Financial Margin, a non-GAAP financial measure, as a key internal financial metric. For additional information regarding Financial Margin, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations-Energy Services . Risk Management In conducting its business, ES mitigates risk by following formal risk management guidelines, including transaction limits, segregation of duties and formal contract and credit review approval processes. ES continuously monitors and seeks to reduce the risk associated with its counterparty credit exposures. Our Risk Management Committee oversees compliance with these established guidelines. Storage and Transportation ST includes investments in FERC-regulated interstate natural gas storage and transportation assets and is comprised of the following subsidiaries: NJR Midstream Company owns and operates Leaf River, a 32.2M Dth salt dome natural gas facility, located in southeastern Mississippi, and the FERC-regulated Adelphia, which owns and operates an 84-mile pipeline in southeastern Pennsylvania. NJR Midstream Company also holds a 20% equity method investment in PennEast, whose project was cancelled in September 2021 and subsequently is dissolving the partnership; and NJR Steckman Ridge Storage Company holds our 50% equity method investment in Steckman Ridge. Steckman Ridge is a Delaware limited partnership, jointly owned and controlled by our subsidiaries and subsidiaries of Enbridge Inc., which built, owns and operates a natural gas storage facility with up to 12 Bcf of working natural gas capacity in Bedford County, Pennsylvania. The facility has direct access to the TETCO and Eastern Gas Transmission and Storage, Inc. pipelines and has access to the Northeast and Mid-Atlantic markets. OTHER BUSINESS OPERATIONS Home Services and Other HSO operations consist primarily of the following unregulated affiliates: NJR Home Services, Inc., which provides heating, ventilation and cooling service, sales and installation of appliances to approximately 101,500 service contract customers, as well as installation of solar equipment; NJR Plumbing Services, Inc., which provides plumbing repair and installation services; New Jersey Resources

Corporation, a diversified energy services holding company; CRR, which holds commercial real estate; and NJR Service Corporation, which provides shared administrative and financial services to the Company and all of its subsidiaries and affiliates. ENVIRONMENT We, along with our subsidiaries, are subject to legislation and regulation by federal, state and local authorities with respect to environmental matters. We believe that we are, in all material respects, in compliance with all applicable environmental laws and regulations. NJNG is responsible for the environmental remediation of identified former MGP sites, which contain contaminated residues from former gas manufacturing operations that ceased at these sites by the mid-1950s and, in some cases, had been discontinued many years earlier. NJNG periodically, and at least annually, performs an environmental review of the former MGP sites, including a review of potential estimated liabilities related to the investigation and remedial action on these sites. Based on this review, NJNG has estimated that the total future expenditures to remediate and monitor the former MGP sites for which it is responsible will range from approximately $137.3M to $201.5M. NJNGs estimate of these liabilities is based upon known and measurable facts, existing technology and enacted laws and regulations in place when the review was completed in fiscal 2023. Where it is probable that costs will be incurred, and the information is sufficient to establish a range of possible liability, NJNG accrues the most likely amount in the range. If no point within the range is more likely than the other, it is NJNGs policy to accrue the lower end of the range. As of September 30, 2023, NJNG recorded an MGP remediation liability and a corresponding regulatory asset of $169.4M on the Consolidated Balance Sheets, based on the most likely amount; however, actual costs may differ from these estimates. HUMAN CAPITAL RESOURCES Employee Overview NJR fundamentally believes that its employees make the Company a unique, successful organization in creativity, commitment, ingenuity, hard work and innovation. NJR employees fulfill the responsibilities that enable the Company to deliver natural gas service to its customers; to be a leader in clean energy investments; to grow its storage and transportation energy business; and to earn the loyalty of its retail home services customers. NJR also is committed to provide every appropriate resource to ensure its employees safety. Through initiatives that start at the top, NJR has invested time, energy and manpower to foster a culture where safety is top-of-mind at all times, and where achieving safety goals is a shared priority for every NJR employee. As of September 30, 2023, the Company and our subsidiaries employed 1,350 employees compared with 1,288 employees as of September 30, 2022. Of the total number of employees, NJNG had 509 and 498 and NJRHS had 117 and 113 Union or Represented employees as of September 30, 2023 and 2022, respectively. NJNG and NJRHS have collective bargaining agreements with the Union, which is affiliated with the American Federation of Labor and Congress of Industrial Organizations. NJNG and the Union are in active negotiations to extend the collective bargaining agreement, which is scheduled to expire on December 7, 2023. The collective bargaining agreement between NJRHS and the Union is scheduled to expire April 2, 2024. The labor agreements cover wage increases and other benefits, including the defined benefit pension (which was closed to all employees hired on or after January 1, 2012, with the exception of certain rehires who are eligible to resume active participation), the postemployment benefit plan (which was closed to all employees hired on or after January 1, 2012) and the enhanced 401(k) retirement savings plan. We consider our relationship with employees, including those covered by collective bargaining agreements, to be in good standing. The Company depends on its key personnel to successfully operate its businesses, including its executive officers, senior corporate management and management at its operating units. NJR seeks to attract and retain its employees by offering competitive compensation packages including base and incentive compensation (and in certain instances share-based compensation and retention incentives), attractive benefits and opportunities for advancement and rewarding careers. NJR periodically reviews and adjusts, if needed, its employees total compensation (including salaries, annual cash incentive compensation, other cash and equity incentives and benefits) to ensure that it is competitive within the industry and is consistent with our level of performance. NJR has also implemented enterprise-wide talent development and succession planning programs designed to identify future talent for key positions. To promote a collaborative and rewarding work environment and support the communities we serve, NJR sponsors numerous charitable, philanthropic and social awareness programs. Further, in order to take advantage of available opportunities and successfully implement our long-term strategy, NJR must be able to employ, train and retain the necessary skilled employees. As a result, NJR supports and utilizes various training and educational programs and has developed additional company-wide and project-specific employee training and educational programs. NJR continues key programs focused on employee safety, leadership development, work-life balance, talent management, health and wellness, DEI and employee engagement. Moreover, DEI and employee engagement are integral to NJRs vision, strategy and business success. Fostering an environment that values DEI and ethics helps create an organization Page 13 New Jersey Resources Corporation Part I ITEM 1. BUSINESS (Continued) that is able to embrace, leverage and respect the differences of employees, customers and the communities where we live, work and serve. We are proud of the strides we have made in furthering our DEI strategy and increasing employee engagement. NJR is committed to this journey and knows our success makes us stronger as a company and community. Complementing our efforts are a DEI Council and our seven employee-led Business Resource Groups, cross-functional teams of employees whose core mission is to advance their own professional development and cultivate deeper connections with co-workers and communities. NJR periodically evaluates employees and their productivity against future demand expectations and historical trends. NJR employees continue to maintain high levels of engagement, satisfaction and retention according to NJRs most recent employee survey. NJR Board of Directors Role in Human Capital Resource Management NJRs Board of Directors believes that human capital management is an important component of the Companys continued growth and success, and is essential for our ability to attract, retain and develop talented and skilled employees. We pride ourselves on a culture that is innovative, talent- and team-focused and inclusive. Management regularly reports to the LDCC of the Board of Directors on human capital management topics, including corporate culture, DEI, employee development, compensation and benefits. The LDCC maintains oversight of matters related to human capital management, including talent retention, development and succession planning, and the Board of Directors provides input on important decisions in each of these areas. NJR conducts an annual employee feedback survey, which is reviewed by the LDCC, designed to help the Company measure overall employee engagement. The feedback employees provide through the survey helps NJR evaluate the Companys culture and the employee experience and monitor its current practices for potential areas of improvement. Employee Benefits The LDCC believes employee benefits are an essential component of the Companys competitive total rewards package. These benefits are designed to attract and retain our employees and include medical, vision and dental insurance, short- and long-term disability insurance, accidental death and disability insurance, travel and accident insurance and our 401(k) Plan. As part of the 401(k) Plan, NJR matches 85% of the first 6% of compensation contributed by the employee into the 401(k) Plan, subject to the Internal Revenue Code and NJRs 401(k) Plan limits. Additionally, for employees who are not eligible to participate in the defined benefit plans, NJR annually contributes between 3.5% and 4.5% of base compensation, depending upon years of service, into the 401(k) Plan on their behalf. AVAILABLE INFORMATION AND CORPORATE GOVERNANCE DOCUMENTS The following reports and any amendments to those reports are available free of charge on our website at https://investor.njresources.com/financials/sec-filings/default.aspx as soon as reasonably possible after filing or furnishing them with the SEC: Annual reports on Form 10-K; Quarterly reports on Form 10-Q; and Current reports on Form 8-K. The following documents are available free of charge on our website at https://investor.njresources.com/governance/governance-documents/default.aspx NJR Code of Conduct; Amended and Restated Bylaws; Corporate Governance Guidelines; Wholesale Trading Code of Conduct; Charters of the following Board of Directors Committees: Audit, Nominating/Corporate Governance and Leadership Development and Compensation; Audit Complaint Procedure; Communicating with Non-Management Directors Procedure; Statement of Policy with Respect to Related Person Transactions; and Legal Procedure. In Part III of this Form 10-K, we incorporate certain information by reference from our Proxy Statement for our 2023 Annual Meeting of Shareowners. We expect to file the Proxy Statement with the SEC on or about December 14, 2023. We will make it available on our website as soon as reasonably possible following the filing date. Please refer to the Proxy Statement when it is available. Page 14 New Jersey Resources Corporation Part I ITEM 1. BUSINESS (Continued) A printed copy of each document is available free of charge to any shareowner who requests it by contacting the Corporate Secretary at New Jersey Resources Corporation, 1415 Wyckoff Road, Wall, New Jersey 07719. INFORMATION ABOUT OUR EXECUTIVE OFFICERS The Companys Executive Officers and their age, position and business experience during the past five years are below. ##TABLE_START Name Age Officer since Business experience during last five years Stephen D. Westhoven 55 2004 President and Chief Executive Officer (October 2019 - present) President and Chief Operating Officer (October 2018 - September 2019) Roberto Bel 50 2019 Senior Vice President and Chief Financial Officer (January 2022 - present) Vice President, Treasury and Investor Relations (April 2019 - December 2021) Assistant Treasurer at Refinitiv (October 2018 - March 2019) Patrick J. Migliaccio 49 2013 Senior Vice President and Chief Operating Officer (January 2022 - present) Senior Vice President and Chief Financial Officer (January 2016 - December 2021) Amy Cradic 52 2018 Senior Vice President and Chief Operating Officer of Nonutility Businesses, Strategy and External Affairs (March 2020 - present) Vice President, Corporate Strategy and External Affairs (January 2020 February 2020) Vice President, Government Affairs and Policy (January 2018 December 2019) Richard Reich 48 2016 Senior Vice President and General Counsel (June 2022 - present) Senior Vice President, General Counsel and Corporate Secretary (September 2021 - June 2022) Corporate Secretary and Assistant General Counsel (January 2016 - September 2021) Lori DelGiudice 48 2023 Senior Vice President, Human Resources (November 2022 - present) Vice President of Human Resources for Honeywell Advanced Materials (September 2017 - October 2022) Jacqueline K. Shea 59 2016 Senior Vice President and Chief Information Officer (January 2023 - present) Vice President and Chief Information Officer (June 2016 - December 2022) Stephen M. Skrocki 47 2023 Corporate Controller (Principal Accounting Officer) (January 2023 - present) Corporate Controller (January 2021 - December 2022) Assistant Corporate Controller (March 2017 - January 2021) ##TABLE_END ITEM 1A. RISK FACTORS When considering any investment in our securities, investors should consider the following risk factors, as well as the information contained under the caption Information Concerning Forward-Looking Statements, in analyzing our present and future business performance. While this list is not exhaustive, management also places no priority or likelihood based on their descriptions or order of presentation. Listed below, not necessarily in order of importance or probability of occurrence, are the most significant risk factors applicable to us. Unless indicated otherwise or the content requires otherwise, references below to we, us, and our should be read to refer to the Company and its subsidiaries and affiliates. ##TABLE_START Risks Related to Our Business Operations ##TABLE_ENDOur investments in solar energy projects are subject to substantial risks and uncertainties. Our investments in commercial and residential solar energy projects are dependent, in part, upon current state regulatory incentives and federal tax credits in order for the projects to be economically viable. Our return on investment for these solar projects is based substantially on our eligibility for ITCs and the future market value of SRECs that are traded in a competitive marketplace in the State of New Jersey. These projects face the risk that the current state regulatory programs and tax laws may expire or be adversely modified. A sustained decrease in the value of SRECs could negatively impact the return on our investments and could impair our portfolio of solar assets. In addition, there are risks associated with our ability to execute on our investment strategy of clean energy projects, which includes our ability to develop and manage such projects profitably. These include logistical risks and potential delays related to construction, permitting and regulatory approvals (including any approvals by the BPU required pursuant to solar energy legislation in the State of New Jersey, and similar approvals required by the other states where our solar projects are located); electric grid interconnection delays associated with the PJM Interconnection, LLC queue reform process; and the operational risk that the projects in service will not perform according to expectations due to equipment failure, suboptimal weather conditions or other economic factors beyond our control. All of the aforementioned risks could reduce the availability of viable solar energy projects for development. Furthermore, at the development or acquisition stage, our ability to predict actual performance results may be hindered or inaccurate and the projects may not perform as predicted. Page 15 New Jersey Resources Corporation Part I ITEM 1A. RISK FACTORS (Continued) Actions or limitations to address concerns over long-term climate change, both globally and within our utilities' service areas, may affect our operations and financial performance. Legislative, regulatory and advocacy efforts at the local, state and national levels concerning climate change and other environmental issues could have significant impacts on our operations. The natural gas utility industry may be affected by proposals to curb greenhouse gas and other air emissions. Various regulatory and legislative proposals have been made to limit or further restrict byproducts of combustion, including byproducts resulting from the use of natural gas by our customers. In addition, regionally, a number of regulatory and legislative initiatives have been passed that are designed to limit greenhouse gas emissions and increase the use of renewable sources of energy, such as the ban of natural gas equipment in new construction in New York. In addition, regulatory and legislative initiatives may restrict customers access to natural gas and/or require or limit natural gas infrastructure in buildings. Other initiatives may seek to promote social interests expressed as energy equity, environmental justice or similar frameworks. Any such legislation could direct and/or restrict the operation and raise the costs of our energy delivery infrastructure as well as the distribution of natural gas to our customers. Uncertainties associated with our pipeline of projects could adversely affect our business, results of operations, financial condition and cash flows. Business development projects involve many risks. We are currently engaged in business development projects, including projects in various stages of development tied to decarbonization efforts. Timely completion of our projects is subject to certain risks, including those related to regulatory proceedings regarding permitting and adverse outcomes from legal challenges related to the projects authorizations from federal and state regulatory agencies. We could also experience issues such as: technological challenges; ineffective scalability; failure to achieve expected outcomes; unsuccessful business models; startup and construction delays;

construction cost overruns; disputes with contractors; the inability to negotiate acceptable agreements such as rights-of-way, easements, construction, gas supply or other material contracts; changes in customer demand, perception or commitment; public opposition to projects; marketing risk and changes in market regulation, behavior or prices; market volatility or unavailability, including markets for RNG and its associated attributes or other environmental attributes; the inability to receive expected tax or regulatory treatment; and operating cost increases. Additionally, we may be unable to finance our business development projects at acceptable costs or within a scheduled time frame necessary for completing the project. Any of the foregoing risks, if realized, could result in business development efforts failing to produce expected financial results and the project investment becoming impaired, and such failure or impairment could have an adverse effect on our business, results of operations, financial condition and cash flows. ESs earnings and cash flows are dependent upon optimization of its physical assets. ES s earnings and cash flows are based, in part, on its ability to optimize its portfolio of contractually based natural gas storage and pipeline assets. The optimization strategy involves utilizing its physical assets to take advantage of differences in natural gas prices between geographic locations and/or time periods. Any change among various pricing points could affect these differentials. In addition, significant increases in the supply of natural gas in ESs market areas, including as a result of increased production along the Marcellus Shale, can reduce ESs ability to take advantage of pricing fluctuations in the future. Changes in pricing dynamics and supply could have an adverse impact on ESs optimization activities, earnings and cash flows. ES incurs fixed demand fees to acquire its contractual rights to transportation and storage assets. Should commodity prices at various locations or time periods change in such a way that ES is not able to recoup these costs from its customers, the cash flows and earnings at ES, and ultimately the Company, could be adversely impacted. NJNG and ES rely on storage, transportation assets and suppliers, which they do not own or control, to deliver natural gas. NJNG and ES depend on natural gas pipelines and other transportation and storage facilities owned and operated by third parties to deliver natural gas to wholesale and retail markets and to provide retail energy services to customers. Their ability to provide natural gas for their present and projected sales will depend upon their suppliers ability to obtain and deliver additional supplies of natural gas, as well as NJNGs ability to acquire supplies directly from new sources. Factors beyond the control of NJNG, its suppliers and the independent suppliers that have obligations to provide natural gas to certain NJNG customers may affect NJNGs ability to deliver such supplies. These factors include other parties control over the drilling of new wells and the facilities to transport natural gas to NJNGs citygate stations; development of additional interstate pipeline infrastructure; availability of supply sources; third-party pipelines or other midstream facilities interconnected to our gathering or transportation system, such as the TETCO or Transcontinental Pipeline, becoming partially or fully unavailable; competition for the acquisition of natural gas; priority allocations; impact of severe weather disruptions to natural gas supplies; and the regulatory and pricing policies of federal and state regulatory agencies, as well as the availability of Canadian reserves for export to the U.S. Energy deregulation legislation may increase competition among natural gas utilities and impact the quantities of natural gas requirements needed for sales service. ES also relies on a firm supply source to meet its energy management obligations to its customers. If supply, transportation or storage is disrupted, including for reasons of force majeure, the ability of NJNG and ES to sell and deliver their products and services may be hindered. As a result, they may be responsible for damages incurred by their customers, such as the additional cost of acquiring alternative supply at then-current Page 16 New Jersey Resources Corporation Part I ITEM 1A. RISK FACTORS (Continued) market rates. Particularly for ES, these conditions could have a material impact on our financial condition, results of operations and cash flows. Failure to attract and retain an appropriately qualified employee workforce could adversely affect operations. Our ability to implement our business strategy and serve our customers is dependent upon our continuing ability to attract and retain talented professionals and a technically skilled workforce, and being able to transfer the knowledge and expertise of our workforce to new employees as our aging employees retire. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor could adversely affect the ability to manage and operate our business. NJNG and the Union are in active negotiations to extend the collective bargaining agreement, which is scheduled to expire on December 7, 2023. The collective bargaining agreement between NJRHS and the Union is scheduled to expire April 2, 2024. Disputes with the Union over terms and conditions of the agreements could result in instability in our labor relationship and work stoppages that could impair the timely delivery of natural gas and other services from our utility and Home Services business, which could strain relationships with customers and state regulators and cause a loss of revenues that could adversely affect our results of operations. Our collective bargaining agreements may also increase the cost of employing NJNG and Home Services workforce, affect our ability to continue offering market-based salaries and employee benefits, limit our flexibility in dealing with our workforce and limit our ability to change work rules and practices and implement other efficiency-related improvements to successfully compete in todays challenging marketplace. Our success depends upon our ability to attract, effectively transition, motivate and retain key employees and identify and develop talent to succeed senior management. We depend on senior executive officers and other key personnel to develop, implement and execute on our overall business strategy. The inability to recruit and retain or effectively transition key personnel or the unexpected loss of key personnel may adversely affect our operations. We may be unable to obtain governmental approvals, property rights and/or financing for the construction, development and operation of our proposed energy investments and projects in a timely manner or at all. Construction, development and operation of energy investments, such as Leaf River and other natural gas storage facilities, NJNG infrastructure improvements, pipeline transportation systems, such as the Adelphia pipeline project, and solar energy projects, are subject to federal and state regulatory oversight and require certain property rights, such as easements and rights-of-way from public and private property owners, as well as regulatory approvals, including environmental and other permits and licenses for such facilities and systems. We or our joint venture partnerships may be unable to obtain, in a cost-efficient or timely manner, all such needed property rights, permits and licenses to construct and develop our energy facilities and systems. Successful financing of our energy investments requires participation by willing financial institutions and lenders, as well as acquisition of capital at reasonable interest rates. If we do not obtain the necessary regulatory approvals or property rights, or if we are unable to enter into contracts with counterparties at reasonable rates, or obtain financing, our assets or equity method investments could be impaired. Such impairment could have a materially adverse effect on our financial condition, results of operations and cash flows. Weather and weather patterns, including normal seasonal and quarterly fluctuations of weather, as well as extreme weather events that, individually or in aggregate, may be associated with climate change, could adversely affect our ability to manage our operational requirements to serve our customers, and ultimately adversely affect our results of operations and liquidity. NJNGs business is seasonal, and weather patterns can have a material impact on our financial performance. Demand for natural gas is often greater in the summer and winter months associated with cooling and heating. Because natural gas is heavily used for residential and commercial heating, the demand for this product depends heavily upon weather patterns throughout our market areas, and a significant amount of natural gas revenues are recognized in the first and second quarters related to the heating season. Accordingly, our operations have historically generated less revenue and income when weather conditions are milder in the winter and cooler in the summer. Unusually mild winters or cool summers could adversely affect our results of operations and financial position. In addition, exceptionally hot summer weather or unusually cold winter weather could add significantly to working capital needs to fund higher than normal supply purchases to meet customer demand for natural gas. While we believe the CIP mitigates the impact of weather variations on NJNGs Utility Gross Margin, severe weather conditions may have an impact on the ability of suppliers and pipelines to deliver the natural gas to NJNG, which can negatively affect our earnings. The CIP does not mitigate the impact of severe weather conditions on our cash flows. Future results at ES are subject to volatility in the natural gas market due to weather. Variations in weather may affect earnings and working capital needs throughout the year. During periods of milder temperatures, demand and volatility in the natural gas market may decrease, which can negatively impact ESs earnings and cash flows. Page 17 New Jersey Resources Corporation Part I ITEM 1A. RISK FACTORS (Continued) Severe weather impacts, including, but not limited to, hurricanes, thunderstorms, high winds, microbursts, fires, tornadoes, blizzards and snow or ice storms, can disrupt energy generation, transmission and distribution. Extreme weather conditions, especially those of prolonged duration, create high energy demand on our own and/or other systems and increase the risk that we may be unable to reliably serve customers. Risk of losing gas supply during extreme weather carries significant consequences, as without our services our customers may be subjected to dire circumstances. Additionally, extreme weather conditions may cause the breakdown of or damage to equipment essential to the operation of our assets, and could also raise market prices as we buy short-term energy to serve our own system. To the extent the frequency of extreme weather events increases, this could increase our cost of providing service. In addition, we may not recover all costs related to mitigating these physical and financial risks. There is also a concern that the physical risks of climate change could include changes in weather conditions, such as changes in the amount or type of precipitation and extreme weather events. Climate change and the costs that may be associated with its impacts have the potential to affect our business in many ways, including increasing the cost incurred in providing natural gas, impacting the demand for and consumption of natural gas (due to change in both costs and weather patterns) and affecting the economic health of the regions in which we operate. We may be adversely impacted by natural disasters, pandemic illness, war or terrorist activities and other extreme events to which we may be unable to promptly respond. Local or national natural disasters, pandemic illness, actual or threatened acts of war or terrorist activities, including the political and economic disruption and uncertainty related to Russias military invasion of Ukraine and the Israel-Hamas war, catastrophic failure of the interstate pipeline system and other extreme events are a threat to our assets and operations. Companies in our industry that are located in our service territory may face a heightened risk due to exposure to acts of terrorism that could target or impact our natural gas distribution, transmission and storage facilities and disrupt our operations and ability to meet customer requirements. In addition, the threat of terrorist activities could lead to increased economic instability and volatility in the price of natural gas that could affect our operations. Natural disasters, political unrest or actual or threatened terrorist activities may also disrupt capital markets and our ability to raise capital or may impact our suppliers or our customers directly. A local disaster or pandemic illness could result in part of our workforce being unable to operate or maintain our infrastructure or perform other tasks necessary to conduct our business. In addition, these risks could result in loss of human life, significant damage to property, environmental damage, impairment of our operations and substantial loss to the Company. Such uncertain conditions may also impact the ability of certain customers to pay for services, which could affect the collectability and recognition of our revenues and adversely affect our financial results. Our regulators may not allow us to recover from our customers part or all of the increased cost related to the foregoing events, which could negatively affect our financial condition, results of operations and cash flows. A slow or inadequate response to events that could cause business interruption may have an adverse impact on operations and earnings. We may be unable to obtain sufficient insurance (or such insurance may be costly) to cover all risks associated with local and national disasters, pandemic illness, terrorist activities, catastrophic failure of the interstate pipeline system and other events, which could increase the risk that an event adversely affects our financial condition, results of operations and cash flows. ##TABLE_START Risks Related to Technologies ##TABLE_ENDCyberattacks, ransomware, terrorism, other malicious acts against, or failure of, information technology systems could adversely affect our business operations, financial condition and results of operations. We continue to place ever-greater reliance on technological tools that support our business operations and corporate functions, including tools that help us manage our natural gas distribution and energy trading operations and infrastructure. The failure of, or security breaches related to, these technologies could materially adversely affect our business operations, financial position, results of operations and cash flows. We rely on information technology to manage our natural gas distribution and storage, energy trading and other corporate operations; maintain customer, employee, Company and vendor data; and prepare our financial statements and perform other critical business processes. This technology may fail due to cyberattack, physical disruption, design and implementation defects or human error. Disruption or failure of business operations and information technology systems could harm our facilities or otherwise adversely impact our ability to safely deliver natural gas to our customers, serve our customers effectively or manage our assets. Additionally, an attack on, or failure of, information technology systems could result in the unauthorized release of customer, employee or other confidential or sensitive data. Cyberattacks, ransomware, terrorism, increased use of artificial intelligence technologies or other malicious acts could damage, destroy or disrupt these systems for an extended period of time. The energy sector, including natural gas utility companies has become the subject of cyberattacks with increased frequency. Page 18 New Jersey Resources Corporation Part I ITEM 1A. RISK FACTORS (Continued) Additionally, the facilities and systems of clients, suppliers and third-party service providers could be vulnerable to the same cyber or terrorism risks as our facilities and systems, and such third-party systems may be interconnected to our systems both physically and technologically. Therefore, an event caused by cyberattacks, ransomware or other malicious acts at an interconnected third party could impact our business and facilities. Any failure or unexpected or unauthorized use of technology systems could result in the unavailability of such systems, and could result in a loss of operating revenues, an increase in operating expenses and costs to repair or replace damaged assets. Any of the above could also result in the loss or release of confidential customer and/or employee information or other proprietary data that could adversely affect our reputation and competitiveness, could result in costly litigation and negatively impact our results of operations. These cyberattacks have become more common and sophisticated and, as such, we could be required to incur costs to strengthen our systems and respond to emerging concerns. There is no guarantee that redundancies built into our networks and technology, or the procedures we have implemented to protect against cyberattacks and other unauthorized access to secured data, will guarantee protection against all failures of technology or security breaches.

Furthermore, despite our efforts to investigate, improve and remediate the capability and performance of our information technology system, we may not be able to discover all weaknesses, breaches and vulnerabilities, and failure to do so may expose us to higher risk of data loss and adversely affect our business operations and results of operations. Failure to keep pace with technological change may limit customer growth and have an adverse effect on our operations. Advances in technology and changes in laws or regulations are reducing the cost of alternative methods of producing energy. In addition, customers are increasingly expecting enhanced communications regarding their electric and natural gas services, which, in some cases, may involve additional investments in technology. New technologies, including, but not limited to, cloud computing and generative artificial intelligence, may require us to make significant expenditures to remain competitive and may result in the obsolescence of certain of our operating assets. Our future success will depend, in part, on our ability to anticipate and successfully adapt to technological changes and to offer services that meet customer demand. Failure to adapt to advances in technology and manage the related costs could make us less competitive and negatively impact our financial condition, results of operations and cash flows. ##TABLE_START Risks Related to Regulations and Litigation ##TABLE_ENDWe are subject to governmental regulation. Compliance with current and future regulatory requirements and procurement of necessary approvals, permits and certificates may result in substantial costs to us. We are subject to substantial regulation from federal, state and local authorities. We are required to comply with numerous laws and regulations and to obtain numerous authorizations, permits, approvals and certificates from governmental agencies. These agencies regulate various aspects of our business, including customer rates, services, construction and natural gas pipeline operations. FERC has regulatory authority over some of our operations, including sales of natural gas in the wholesale and retail markets and the purchase and sale of interstate pipeline and storage capacity, including Steckman Ridge, Leaf River and Adelphia. Any Congressional legislation or agency regulation that would alter these or other similar statutory and regulatory structures in a way to significantly raise costs that could not be recovered in rates from customers, that would reduce the availability of supply or capacity or that would reduce our competitiveness could negatively impact our earnings. In addition, changes in and compliance with laws such as the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 could increase federal regulatory oversight and administrative costs that may not be recovered in rates from customers, which could have an adverse effect on our earnings. We cannot predict the impact of any future revisions or changes in interpretations of existing regulations or the adoption of new laws and applicable regulations. Changes in regulations or the imposition of additional regulations could influence our operating environment and may result in substantial costs to us. Page 19 New Jersey Resources Corporation Part I ITEM 1A. RISK FACTORS (Continued) Our regulated operations are subject to certain operating risks incidental to handling, storing, transporting and providing customers with natural gas. Our regulated operations are subject to all operating hazards and risks incidental to handling, storing, transporting and providing customers with natural gas, including our natural gas vehicle refueling stations and LNG facilities. These risks include catastrophic failure of the interstate pipeline system, explosions, pollution, release of toxic substances, fires, storms, safety issues and other adverse weather conditions and hazards, each of which could result in damage to or destruction of facilities or damage to persons and property. We could suffer substantial losses should any of these events occur. Although we maintain insurance coverage, insurance may not be sufficient to cover all material expenses related to these risks, and such insurance may be costly. We are involved in legal or administrative proceedings before various courts and governmental bodies that could adversely affect our results of operations, cash flows and financial condition. In the ordinary conduct of business, we are involved in legal or administrative proceedings before various courts and governmental bodies with respect to general claims, rates, permitting, taxes, environmental issues, natural gas cost prudence reviews and other matters. Adverse decisions regarding these matters, to the extent they require us to make payments in excess of amounts provided for in our financial statements or are not covered by insurance or indemnity rights, could adversely affect our results of operations, cash flows and financial condition. Our costs of compliance with present and future environmental laws are significant and could adversely affect our cash flows and profitability. Our operations are subject to federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources and site remediation. Compliance with these laws and regulations may require us to expend financial resources to, among other things, conduct site remediation and perform environmental monitoring. If we fail to comply with applicable environmental laws and regulations, even if we are unable to do so due to factors beyond our control, we may be subject to civil liabilities or criminal penalties and may be required to incur expenditures to come into compliance. Additionally, any alleged violations of environmental laws and regulations may require us to expend resources in our defense against alleged violations. Furthermore, the U.S. Congress has for some time been considering various forms of climate change legislation. In addition, in July 2019, the State of New Jersey amended the GWRA, which targets 80% reduction in greenhouse gas emissions below 2006 levels economy-wide by 2050. In January 2020, Governor Murphy released the EMP confirming his commitment to achieve 100% clean energy by 2050, and the GWRA mandate of reducing state greenhouse gas emissions. The EMP addressed New Jerseys energy system, including electric generation, transportation and buildings, and their associated greenhouse gas emissions and related air pollutants. The EMP defines 100% clean energy by 2050 to mean 100% carbon-neutral electric generation and maximum electrification of the transportation and building sectors, which are the greatest carbon emission-producing sectors in the state, to meet or exceed the GWRA emissions reductions by 2050. Our goals, to reduce our New Jersey operational emissions by 60% from 2006 levels by 2030 and to achieve net-zero carbon emissions from our New Jersey operations by 2050, may require additional technological, legislative and regulatory developments, the impacts and costs of which may not be fully known at this time. While the EMP does not place a moratorium or end date on natural gas hook ups, further legislation or rulemaking that de-emphasizes the role of natural gas in providing clean, low-cost energy in the state of New Jersey could put upward pressure on natural gas prices and place customer growth targets at risk. Higher cost levels could impact the competitive position of natural gas and negatively affect our growth opportunities, cash flows and earnings. In February 2023, Governor Murphy issued two executive orders that established, or accelerated, previously established 2050 targets for clean-sourced electricity and electric heat pump adoption, with target dates of 2030 or 2035, as applicable. An additional executive order opened a proceeding to plan for the future of natural gas utilities in New Jersey. We are unable to predict the outcomes of these proceedings, but they could have a material impacts on our business, results of operations and cash flows. Risks related to regulation could affect the rates we are able to charge, various costs and our profitability. NJNG is subject to regulation by federal, state and local authorities. These authorities regulate many aspects of NJNGs distribution and transmission operations, including construction and maintenance of facilities, operations, safety, tariff rates that NJNG can charge customers, rates of return, the authorized cost of capital, recovery of pipeline replacement, environmental remediation costs and relationships with its affiliates. NJNGs ability to timely construct rate-based assets and obtain rate increases, including base rate increases, continue its BGSS incentive and CIP programs and maintain its currently authorized rates of return may be impacted by events, including regulatory or legislative actions. Additionally, in fiscal 2019, NJR began the process of transitioning away from its enterprise platform, which will no longer receive extended support after 2025. The first Page 20 New Jersey Resources Corporation Part I ITEM 1A. RISK FACTORS (Continued) phase of IT enhancements and upgrades were placed into service in July 2020. The remaining phases of planned upgrades relate to work order and asset management and customer information systems and experience, which are expected to require significant capital investment through fiscal year 2024. There can be no assurance that NJNG will be able to obtain rate increases and continue its BGSS incentive, CIP, RAC, or SAVEGREEN programs and IT upgrades and enhancements or continue to earn its currently authorized rates of return. Adelphia is subject to regulation by FERC. FERC regulates many aspects of Adelphias transmission operations, including construction and maintenance of facilities, operations, safety tariff rates that Adelphia can charge customers, rates of return, the authorized cost of capital, recovery of pipeline replacement and relations with its affiliates. Adelphias ability to obtain rate increases and maintain its currently authorized rates of return may be impacted by events, including regulatory or legislative actions. There can be no assurance that Adelphia will be able to obtain rate increases or continue to earn its currently authorized rate of return. ##TABLE_START Risks Related to Our Markets ##TABLE_ENDMajor changes in the supply and price of natural gas may affect financial results. While NJRES and

NJNG expect to meet customers demand for natural gas for the foreseeable future, factors affecting suppliers and other third parties, including the inability to develop additional interstate pipeline infrastructure, lack of supply sources, increased competition, further deregulation, transportation costs, possible climate change legislation, energy efficiency mandates or changes in consumer behaviors, transportation availability and drilling for new natural gas resources, may impact the supply and price of natural gas. In addition, any significant disruption in the availability of supplies of natural gas could result in increased supply costs, higher prices for customers and potential supply disruptions to customers. NJRES and NJNG actively hedge against the fluctuation in the price of natural gas by entering into forward and financial contracts with third parties. Should these third parties fail to perform, and regulators not allow the pass-through of expended funds to customers, it may result in a loss that could have a material impact on our financial condition, results of operations and cash flows. Supply chain disruptions may adversely affect Company operations. The Company relies on third-party vendors and manufacturers to supply many of the materials necessary for its operations. Global logistics disruptions have impacted the flow of materials and restricted global trade flows. Manufacturers are competing for a limited supply of key commodities and logistical capacity, which has impacted lead times, pricing, supply and demand. Disruptions or delays in receiving materials; price increases from suppliers or manufacturers; or the inability to source needed materials, which has occurred and could reoccur, could adversely affect the Companys results of operations, financial condition and cash flows. Changes in customer growth may affect earnings and cash flows. NJNGs ability to increase its Utility Gross Margin is dependent upon the new construction housing market, as well as the conversion of customers to natural gas from other fuel sources. During periods of extended economic downturns, prolonged weakness in housing markets or slowdowns in the conversion market, there could be an adverse impact on NJNGs Utility Gross Margin, earnings and cash flows. Furthermore, while our estimates regarding customer growth are based in part upon information from third parties, the estimates have not been verified by an independent source and are subject to the aforementioned risks and uncertainties, which could cause actual results to materially deviate from the estimates. Our economic hedging activities that are designed to protect against commodity and financial market risks, including the use of derivative contracts in the normal course of our business, may cause fluctuations in reported financial results and financial losses that negatively impact results of operations and our stock price. We use derivatives, including futures, forwards, options, swaps and foreign exchange contracts, to manage commodity, financial market and foreign currency risks. The timing of the recognition of gains or losses associated with our economic hedges in accordance with GAAP does not always coincide with the gains or losses on the items being hedged. The difference in accounting can result in volatility in reported results, even though the expected profit margin is essentially unchanged from the dates the transactions were consummated. In addition, we could recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities or if a counterparty fails to perform under a contract. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve managements judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could adversely affect the value of the reported fair value of these contracts. Page 21 New Jersey Resources Corporation Part I ITEM 1A. RISK FACTORS (Continued) We are exposed to market risk and may incur losses in our wholesale business. Our transportation and storage portfolios consist of contracts to transport and store natural gas. The value of our transportation and storage portfolio could be negatively impacted if the value of these contracts changes in a direction or manner that we do not anticipate. In addition, upon expiration of these transportation and storage contracts, to the extent that they are renewed or replaced at less favorable terms, our results of operations and cash flows could be adversely affected. Inflation and increased natural gas costs could adversely impact our customer base and customer collections and increase the Company s level of indebtedness. Inflation has caused, and may continue to cause, increases in certain operating and capital costs. Our regulated businesses have a process in place to review the adequacy of their rates in relation to the increasing cost of providing service and the inherent regulatory lag in adjusting those rates. The ability to control expenses is an important factor that will influence future results. Rapid increases in the price of purchased gas may cause the Company to experience a significant increase in short-term debt because it must pay suppliers for gas when it is purchased, which can be significantly in advance of when these costs may be recovered through the collection from customers and counterparties for gas delivered. Increases in purchased gas costs could also slow collection efforts as NJNG customers may be more likely to delay the payment of their gas bills, leading to higher-than-normal accounts receivable. This situation could also result in higher short-term debt levels and increased bad debt expense. ##TABLE_START Risks Related to Acquisition and Investment Strategies ##TABLE_ENDAny acquisitions that we may undertake involve risks and uncertainties. We may not realize the anticipated synergies, cost savings and growth opportunities as a result of these transactions. The integration of acquisitions requires significant time and resources. Investments of resources are required to support any acquisition, which could result in significant ongoing operating expenses, and we may experience challenges when combining separate business cultures, information technology systems and employees, and those challenges may divert senior managements time and attention. If we fail to successfully integrate assets and liabilities through the entities which we acquire, we may not fully realize all of the growth opportunities, benefits expected from the transaction, cost savings and other synergies and, as a result, the fair value of assets acquired could be impaired. We assess long-lived assets, including intangible assets associated with acquisitions, for impairment whenever events or circumstances indicate that an assets carrying amount may not be recoverable. To the extent the value of long-lived assets becomes impaired, the impairment charges could have a material impact on our financial condition and results of operations. The benefits that we expect to achieve from acquisitions will depend, in part, on our ability to realize anticipated growth opportunities and other synergies with our existing businesses. The success of these transactions will depend on our ability to integrate these transactions within our existing businesses in a timely and seamless manner. We may experience challenges when combining separate business cultures, information technology systems and employees. Even if we are able to complete an integration successfully, we may not fully realize all the growth opportunities, cost savings and other synergies that we expect. Investing through partnerships or joint ventures decreases our ability to manage risk. We have utilized joint ventures through partnerships for certain ST investments. Although we currently have no specific plans to do so, we may acquire interests in other joint ventures or partnerships in the future. In these joint ventures or partnerships, we may not have the right or power to direct the management and policies of the joint ventures or partnerships, and other participants or investors may take action contrary to our instructions or requests and against our policies and objectives. In addition, the other participants may become bankrupt or have economic or other business interests or goals that are inconsistent with those of NJR and our subsidiaries and affiliates. Our financial condition, results of operations or cash flows could be harmed if a joint venture participant acts contrary to our interests. ##TABLE_START Risks Related to Credit and Liquidity ##TABLE_ENDNJR is a holding company and depends on its operating subsidiaries to meet its financial obligations. NJR is a holding company with no significant assets other than possible cash investments and the stock of its operating subsidiaries. We rely exclusively on dividends from our subsidiaries, on intercompany loans from our unregulated subsidiaries and on the repayments of principal and interest from intercompany loans and reimbursement of expenses from our subsidiaries for our cash flows. Our ability to pay dividends on our common stock and to pay principal and interest on our outstanding debt depends on the payment of dividends to us by our subsidiaries or the repayment of loans to us by our subsidiaries. The extent to which our subsidiaries are unable to pay dividends or repay funds to us may adversely affect our ability to pay dividends to holders of our common stock and principal and interest to holders of our debt. Page 22 New Jersey Resources Corporation Part I ITEM 1A. RISK FACTORS (Continued) Credit rating downgrades could increase financing costs, limit access to the financial markets and negatively affect NJR and its subsidiaries. Rating agencies Moodys and Fitch currently rate NJNGs debt as investment grade. If such ratings are downgraded below investment grade, borrowing costs could increase, as would the costs of maintaining certain contractual relationships and obtaining future financing. Even if ratings are downgraded without falling below investment grade, NJR and NJNG could face increased borrowing costs under their current and future credit facilities. Our ability to borrow and costs of borrowing have a direct impact on our subsidiaries ability to execute their operating strategies, particularly in the case of NJNG, which relies heavily upon capital expenditures financed by its credit facility. If we suffer a reduction in our credit and borrowing capacity or in our ability to issue parental guarantees, the business prospects of ES, CEV and ST, which rely on our creditworthiness, would be adversely affected. ES could possibly be required to comply with various margin or other credit enhancement obligations under its trading and marketing contracts, and it may be unable to continue to trade or be able to do so only on less favorable terms with certain counterparties. CEV could be required to seek alternative financing for its projects and may be unable to obtain such financing or able to do so only on less favorable terms. Additionally, lower credit ratings could adversely affect relationships with NJNGs state regulators, who may be unwilling to allow NJNG to pass along increased costs to its natural gas customers. If we are unable to access the financial markets or there are adverse conditions in the equity or credit markets, including, but not limited to, inflationary pressures, recessionary pressures, or rising interest rates, it could affect managements ability to execute our business plans. We rely on access to both short-term and long-term credit markets as significant sources of liquidity for capital requirements not satisfied by our cash flow from operations. Any deterioration in our financial condition could hamper our ability to access the equity or credit markets or otherwise obtain debt financing on terms favorable to us or at all. In addition, because certain state regulatory approvals may be necessary for NJNG to incur debt, NJNG may be unable to access credit markets on a timely basis. General economic factors beyond our control might create uncertainty that could increase our cost of capital or impair or eliminate our ability to access the debt, equity, or credit markets, including our ability to draw on bank credit facilities. External events could also increase the cost of borrowing or adversely affect our ability to access the financial markets. Such external events could include the following: economic weakness and/or political instability in the U.S. or in the regions where we operate; political conditions, such as a shutdown of the U.S. federal government; financial difficulties of unrelated energy companies; capital market conditions generally; volatility in the equity markets; market prices for natural gas; the overall health of the natural gas utility industry; and fluctuations in interest rates and increased borrowing costs. Failure by NJR and/or NJNG to comply with debt covenants may impact our financial condition. Our long-term debt obligations contain financial covenants related to debt-to-capital ratios. These debt obligations also contain provisions that put limitations on our ability to finance future operations or capital needs or to expand or pursue certain business activities. For example, certain of these agreements contain provisions that, among other things, put limitations on our ability to make loans or investments, make material changes to the nature of our businesses, merge, consolidate or engage in asset sales, grant liens or make negative pledges. Furthermore, the debt obligations and our sale leaseback agreements contain covenants and other provisions requiring us to provide timely delivery of accurate financial statements prepared in accordance with GAAP. The failure to comply with any of these covenants could result in an event of default, which, if not cured or waived, could result in the acceleration of outstanding debt obligations and/or the inability to borrow under existing revolving credit facilities and term loans. We have relied, and continue to rely, upon short-term bank borrowings or commercial paper supported by our revolving credit facilities to finance the execution of a portion of our operating strategies. NJNG is dependent on these capital sources to purchase its natural gas supply and maintain its properties. The acceleration of our outstanding debt obligations and our inability to borrow under the existing revolving credit facilities would cause a material adverse change in NJRs and NJNGs financial condition. Page 23 New Jersey Resources Corporation Part I ITEM 1A. RISK FACTORS (Continued) Our ability to secure short-term financing is subject to conditions in the credit markets. A prolonged constriction of credit availability could affect managements ability to execute our business plan. An inability to access capital may limit our ability to pursue improvements or acquisitions that we may otherwise rely on for both current operations and future growth. ES and NJNG execute derivative transactions with financial institutions as a part of their economic hedging strategy and could incur losses associated with the inability of a financial counterparty to meet or perform under its obligations as a result of adverse conditions in the credit markets or their ability to access capital or post collateral. ##TABLE_START Risks Related to Tax and Accounting Matters ##TABLE_ENDA valuation allowance may be required for our deferred tax assets. Our deferred tax assets are comprised primarily of investment tax credits and state net operating losses. Any revaluation of our deferred tax assets that may be required in the future could have a material adverse impact on our financial condition and results of operations. The cost of providing pension and postemployment health care benefits to employees and eligible former employees is subject to changes in pension fund values, interest rates and changing demographics and may have a material adverse effect on our financial results. We have two defined benefit pension plans and two OPEB plans for the benefit of eligible full-time employees and qualified retirees, which were closed to all employees hired on or after January 1, 2012. The cost of providing these benefits to eligible current and former employees is subject to changes in the market value of the pension and OPEB fund assets, changing discount rates and changing actuarial assumptions based upon demographics, including longer life expectancy of beneficiaries, an expected increase in the number of eligible former employees over the next five years, impacts from healthcare legislation and increases in health care costs. Significant declines in equity markets and/or reductions in bond yields can have a material adverse effect on the funded status of our pension and OPEB plans. In these circumstances, we may be required to recognize increased pension and OPEB expenses and/or be required to make additional cash contributions into the plans. The funded status of these plans, and the related cost reflected in our financial statements, are affected by various factors that are subject to an inherent degree of uncertainty. Under the Pension Protection Act of 2006, losses of asset values may necessitate increased funding of the plans in the future to meet minimum federal government requirements. A significant decrease in the asset values of these plans can result in funding obligations earlier than we had originally planned, which would have a negative impact on cash flows from operations, decrease our borrowing capacity and increase our interest expense. Changes in tax laws, rates or adverse outcomes resulting from examinations by tax authorities may negatively affect our results of operations, net income, financial condition and cash flows. We are subject to taxation and audit by various taxing authorities at the federal, state and local levels. We cannot predict how our federal and state regulators will apply such tax changes in our future rates. While we believe we comply with all applicable tax laws, rules and regulations in the relevant jurisdictions, tax authorities may elect to audit us and determine that we owe additional taxes, which could result in a significant increase in our liabilities for taxes, interest and penalties in excess of our accrued liabilities. New tax legislative initiatives may be proposed from time to time, such as proposals for comprehensive tax reform in the United States, which may impact our effective tax rate and which could adversely affect our tax positions or tax liabilities. On August 16, 2022, the Inflation Reduction Act was signed into law and imposed a 15% minimum tax rate on book earnings for corporations with higher than $1B of annual income, along with a 1% excise tax on corporate stock repurchases while providing tax incentives to promote various clean energy initiatives. We are currently assessing the potential impact of these legislative changes. Any future change in tax laws or interpretation of such laws could adversely affect our results of operations, net income, financial condition and cash flows. Page 24 New Jersey Resources Corporation Part I ITEM 1A. RISK FACTORS (Continued) Significant regulatory assets recorded by our regulated companies could be disallowed for recovery from customers in the future. NJNG records regulatory assets on its financial statements to reflect the ratemaking and regulatory decision-making authority of the BPU as allowed by GAAP. The creation of a regulatory asset allows for the deferral of costs, which, absent a mechanism to recover such costs from customers in rates approved by the BPU, would be charged to expense on its income statement in the period incurred. Primary regulatory assets that are subject to BPU approval include the recovery of BGSS and USF costs, remediation costs associated with NJNGs MGP sites, CIP, NJCEP, economic stimulus plans, certain deferred income taxes and pension and OPEB. If there were to be a change in regulatory positions surrounding the collection of these deferred costs, there could be a material impact on NJNGs existing tariff or a future base rate case, as well as our financial condition, results of operations and cash flows. Adelphia records regulatory assets on its financial statements to reflect the ratemaking and regulatory decision-making authority of FERC as allowed by GAAP. The creation of a regulatory asset allows for the deferral of costs, which, absent a mechanism to recover such costs from customers in rates approved by FERC, would be recorded as a charge to earnings on its Statement of Operations in the period incurred. If there were to be a change in regulatory positions surrounding the collection of these deferred costs, there could be a material impact on Adelphias existing rates or a future rate case, as well as our financial condition, results of operations and cash flows. ##TABLE_START Risks Related to Takeovers ##TABLE_ENDOur restated certificate of incorporation, as amended, and amended and restated bylaws may delay or prevent a transaction that shareowners would view as favorable. Our restated certificate of incorporation, as amended, and amended and restated bylaws, as well as New Jersey law, contain provisions that could delay, defer or prevent an unsolicited change in control of NJR, which may negatively affect the market price of our common stock or the ability of stockholders to participate in a transaction in which they might otherwise receive a premium for their shares over the then-current market price. These provisions may also prevent changes in management. In addition, our Board is authorized to issue preferred stock without stockholder approval on such terms as our Board may determine. Our common shareowners will be subject to, and may be negatively affected by, the rights of any preferred stock that may be issued in the future. In addition, we are subject to the New Jersey Shareholders Protection Act, which could delay or prevent a change of control of NJR. We may also be subject to actions or proposals from activist investors or others that may not be aligned with our long-term strategy or the interests of our other stockholders. This may interfere with our ability to execute our strategic plans, cause uncertainty with our regulators and make it more difficult to attract and retain qualified personnel. Moreover, our stock price could be subject to significant fluctuation or otherwise be adversely affected by the events, risks and uncertainties of any investor activism.

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ITEM 1. BUSINESS N I S OURCE I NC . NiSource Inc. is an energy holding company under the Public Utility Holding Company Act of 2005 whose primary subsidiaries are fully regulated natural gas and electric utility companies, serving approximately 3.7 million customers in six states. NiSource is the successor to an Indiana corporation organized in 1987 under the name of NIPSCO Industries, Inc., which changed its name to NiSource Inc. on April 14, 1999. NiSources principal subsidiaries include NiSource Gas Distribution Group, Inc., a natural gas distribution holding company, and NIPSCO, a gas and electric company. NiSource derives substantially all of its revenues and earnings from the operating results of these rate-regulated businesses. Business Strategy We focus our business strategy on providing safe and reliable service through our core, rate-regulated asset-based utilities, with the goal of adding value to all stakeholders. Our utilities continue to make progress on core safety, infrastructure and environmental investment programs supported by complementary regulatory and customer initiatives across all six states in which we operate. Our goal is to develop strategies that benefit all stakeholders as we (i) embark on long-term infrastructure investment and safety programs to better serve our customers, (ii) align our tariff structures with our cost structure, and (iii) address changing customer conservation patterns. These strategies focus on improving safety and reliability, enhancing customer service, pursuing regulatory and legislative initiatives to increase accessibility for customers currently not on our gas and electric service, ensuring customer affordability and reducing emissions while generating sustainable returns. NiSource remains committed to the advancement of our SMS for the safety of our customers, communities and employees. Our SMS is the established operating model within NiSource. In 2022, NiSource achieved conformance certification to the American Petroleum Institute Recommended Practice 1173, which serves as the guiding practice for our SMS. This certification marks an important milestone for our SMS and NiSources journey towards operational excellence. Moving forward, our focus shifts to maintaining, sustaining and continuously improving the process, procedures, capabilities and talent to enhance safety and reduce operational risk. Additionally, we continue to pursue regulatory and legislative initiatives that will allow customers not currently on our system to obtain gas and electric service in a cost effective manner. NiSource has two reportable segments: Gas Distribution Operations and Electric Operations. The remainder of our operations, which are not significant enough on a stand-alone basis to warrant treatment as an operating segment, are included as Corporate and Other. The activities occurring within this non-segment consist of our centralized financing and treasury activities and are primarily comprised of interest expense on holding company debt and unallocated corporate costs and activities. The following is a summary of the business for each reporting segment. Refer to Item 7, Managements Discussion and Analysis of Financial Condition and Results of Operations and Note 21, "Business Segment Information," in the Notes to Consolidated Financial Statements for additional information related to each segment. Gas Distribution Operations Our natural gas distribution operations serve approximately 3.3 million customers in six states. Through our wholly-owned subsidiary NiSource Gas Distribution Group, Inc., we own five distribution subsidiaries that provide natural gas to approximately 2.4 million residential, commercial and industrial customers in Ohio, Pennsylvania, Virginia, Kentucky, and Maryland. Additionally, we distribute natural gas to approximately 859,000 customers in northern Indiana through our wholly-owned subsidiary NIPSCO. We operate approximately 54,800 miles of distribution main pipeline plus the associated individual customer service lines and 1,000 miles of transmission main pipeline located in our service areas described below. Throughout our service areas we also have gate stations and other operations support facilities. Competition. Open access to natural gas supplies over interstate pipelines and the deregulation of the natural gas supply has led to tremendous change in the energy markets and natural gas competition. Due to open access to natural gas supplies, LDC customers can purchase gas directly from producers and marketers in an open, competitive market. This separation or unbundling of the transportation and other services offered by LDCs allows customers to purchase the commodity independent of services provided by LDCs. LDCs continue to purchase gas and recover the associated costs from their customers. Certain of our Gas Distribution Operations subsidiaries are involved in programs that provide our residential and commercial customers the opportunity to purchase their natural gas requirements from third parties and use our Gas Distribution Operations subsidiaries for transportation services. As of December 31, 2022, 24.5% of our residential customers and 33.3% of our commercial customers participated in such programs. Gas Distribution Operations competes with (i) investor-owned, municipal, and cooperative electric utilities throughout its service areas, (ii) other regulated and unregulated natural gas intra and interstate pipelines and (iii) other alternate fuels, such as propane and fuel oil. Gas Distribution Operations continues to be a strong competitor in the energy market as a result of strong ITEM 1. BUSINESS N I S OURCE I NC . customer preference for natural gas. Competition with providers of electricity has traditionally been the strongest in the residential and commercial markets of Kentucky, southern Ohio, central Pennsylvania and western Virginia due to comparatively low electric rates. Additionally, our gas distribution operations are subject to seasonal fluctuations in sales. Revenues from gas distribution operations are more significant during the heating season, which is primarily from November through March. Please refer to Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations - Results and Discussion of Segment Operations - Gas Distribution Operations," for additional information. Electric Operations We generate, transmit and distribute electricity through our subsidiary NIPSCO to approximately 486,000 customers in 20 counties in the northern part of Indiana and also engage in wholesale electric and transmission transactions. We own and operate sources of generation as well as source power through PPAs. We continue to transition our generation portfolio to primarily renewable sources. During 2021, we operated Rosewater for the full year, Indiana Crossroads Wind went into service during December 2021, and in December of 2022 we closed on the Indiana Crossroads Solar project, which is expected to go into service in 2023. In October 2021, NIPSCO completed the retirement of two coal-burning units with installed capacity of approximately 903 MW at Schahfer Generating Station, located in Wheatfield, IN. We also purchased energy generated from renewable sources through PPAs in 2022. As of December 31, 2022 we have multiple PPAs that provide 500 MW of capacity, with contracts expiring between 2024 and 2040. See below for information on our owned operating facilities: ##TABLE_START Facility Name Location Fuel Type Generating Capacity (MW) (1) R.M. Schahfer Wheatfield, IN Steam - Coal 722 Michigan City Michigan City, IN Steam - Coal 455 Sugar Creek West Terre Haute, IN CCGT 563 R.M. Schahfer Wheatfield, IN Natural Gas 155 Oakdale Carroll County, IN Hydro 9 Norway White County, IN Hydro 7 Rosewater Wind Generation LLC (2) White County, IN Wind 102 Indiana Crossroads Wind Generation LLC (2) White County, IN Wind 302 Total MW Capacity 2,315 ##TABLE_END(1) Represents current net generating capability of each fossil fuel and hydro generating unit. Nameplate capacity is listed for wind generating units. (2) NIPSCO is the managing partner of these JVs. Refer to Note 4, "Variable Interest Entities," in the Notes to Consolidated Financial Statements for more information. In November 2021, NIPSCO submitted its 2021 Integrated Resource Plan ("2021 Plan") with the IURC. The 2021 plan builds upon the 2018 Integrated Resource

Plan which outlined NIPSCOs plan to retire its coal generating assets by 2028. The 2021 plan affirmed the 2018 retirement decisions and calls for the replacement of the retiring units with a diverse portfolio of resources including demand side management resources, modest amounts of incremental solar, stand-alone energy storage, new gas peaking resources and upgrades to existing facilities at the Sugar Creek Generating Station, among other steps. Refer to Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations for further discussion of these plans. NIPSCOs transmission system, with voltages from 69,000 to 765,000 volts, consists of 3,016 circuit miles. NIPSCO is interconnected with eight neighboring electric utilities. NIPSCO participates in the MISO transmission service and wholesale energy market. MISO is a nonprofit organization created in compliance with FERC regulations to improve the flow of electricity in the regional marketplace and to enhance electric reliability. Additionally, MISO is responsible for managing energy markets, transmission constraints and the day-ahead, real-time, Financial Transmission Rights and ancillary markets. NIPSCO has transferred functional control of its electric transmission assets to MISO, and transmission service for NIPSCO occurs under the MISO Open Access Transmission Tariff. NIPSCO generating units are dispatched by MISO which takes into account economics, reliability of the MISO system and unit availability. During the year ended December 31, 2022, NIPSCO generating units were dispatched to meet 41.65% of its load requirements, and NIPSCO purchased 58.35% from the MISO market. ITEM 1. BUSINESS N I S OURCE I NC . Competition. Our electric utilities generally have exclusive service areas under Indiana regulations, and retail electric customers in Indiana do not have the ability to choose their electric supplier. NIPSCO faces non-utility competition from other energy sources, such as self-generation by large industrial customers and other distributed energy sources. Our electric operations are subject to seasonal fluctuations in sales. Revenues from electric operations are more significant during the cooling season, which is primarily from June through September. Please refer to Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations - Results and Discussion of Segment Operations - Electric Operations," for additional information. Political Action The NiSource Political Action Committee ("NiPAC") provides our employees a voice in the political process. NiPAC is a voluntary, employee and director driven and funded political action committee, and NiPAC makes bipartisan political contributions to local, state and federal candidates, where permitted and in accordance with established guidelines. Consistent with our commitments and our approach to engagement, the NiPAC leadership committee members evaluate candidates for support on issues important to our business. Regulatory The regulatory landscape applicable to our operations, including environmental regulations, at both the state and federal levels, continue to evolve. These changes have had and will continue to have an impact on our operations, structure and profitability. Management continually seeks new ways to be more competitive and profitable in this environment, while keeping service and affordability for customers at the forefront. We believe we are, in all material respects, in compliance with such laws and regulations and do not expect continued compliance to have a material impact on our capital expenditures, earnings, or competitive position. We continue to monitor existing and pending laws and regulations, and the impact of regulatory changes cannot be predicted with certainty. Rate Case Actions. The following table describes current rate case actions as applicable in each of our jurisdictions net of tracker impacts. See "Cost Recovery and Trackers" below for further detail on trackers. ##TABLE_START (in millions) Company Proposed ROE Approved ROE Requested Incremental Revenue Approved Incremental Revenue Filed Status Rates Effective Currently Approved in Current or Future Rates Columbia of Pennsylvania (1) 10.95 % None specified $ 82.2 $ 44.5 March 18, 2022 Approved December 8, 2022 December 2022 Columbia of Maryland 10.85 % 9.65 % $ 5.8 $ 3.5 May 13, 2022 Approved November 17, 2022 December 2022 Columbia of Kentucky (2) 10.30 % 9.35 % $ 26.7 $ 18.3 May 28, 2021 Approved December 28, 2021 January 2022 Columbia of Virginia (3) 10.95 % None specified $ 14.2 $ 1.3 August 28, 2018 Approved June 12, 2019 February 2019 Columbia of Ohio 10.95 % 9.60 % $ 221.4 $ 68.2 June 30, 2021 Approved January 26, 2023 March 2023 NIPSCO - Gas (4) 10.50 % 9.85 % $ 109.7 $ 71.8 September 29, 2021 Approved July 27, 2022 September 2022 NIPSCO - Electric 10.80 % 9.75 % $ 21.4 $ (53.5) October 31, 2018 Approved December 4, 2019 January 2020 Active Rate Cases Columbia of Virginia (5) 10.75 % In process $ 40.6 In process April 29, 2022 Order Expected Q1 2023 Interim Rates October 2022 NIPSCO - Electric (6) 10.40 % In process $ 291.8 In process September 19, 2022 Order Expected Q3 2023 September 2023 ##TABLE_END(1) No approved ROE is identified for this matter since the approved revenue increase is the result of a black box settlement under which parties agree upon the amount of increase. (2) The approved ROE for natural gas capital riders (e.g .,SMRP) is 9.275%. (3) Columbia of Virginia's rate case resulted in a black box settlement, representing a settlement to a specific revenue increase but not a specified ROE. The settlement provides use of a 9.70% ROE for future SAVE filings. (4) New rates are implemented in 2 steps, with implementation of Step 1 rates in September 2022. The Step 2 rates were filed on February 21, 2023, with rates effective March 2023. (5) Beginning October 2022, interim rates are being billed subject to refund, pending a final commission order. On December 9, 2022, a Stipulation and Proposed Recommendation was filed with the Virginia State Corporation Commission recommending approval of $25.8 million of incremental revenue. (6) New rates will be implemented in 2 steps, with implementation of Step 1 rates to be effective in September 2023 and Step 2 rates to be effective in March 2024. On February 16, 2023, NIPSCO filed rebuttal updating the requested revenue requirement to $279.2 million. ITEM 1. BUSINESS N I S OURCE I NC . FERC. NiSources service companies and operating companies are subject to varying degrees of regulation by the FERC. NiSource Corporate Services files a FERC Form 60 annual report with its financial information as a FERC jurisdictional centralized service company. NiSource also files an annual FERC Form 61 which contains a narrative description of the service company's functions during the prior calendar year. As natural gas LDCs, Columbia of

Maryland and Columbia of Ohio have limited jurisdictional certificates to transport gas in the respective service territories into interstate commerce. NIPSCO and Columbia of Pennsylvania currently have applications pending at FERC for limited jurisdictional certificates. As an electric company, NIPSCO has Market Based Rate authority and is a Transmission Owner subject to FERC jurisdiction. NIPSCO files the following reports annually: FERC Form 1, which is a comprehensive financial and operating report, FERC Form 566, which is a list of its 20 largest purchases of electricity over the past three years; FERC Form 715, which is its Annual Transmission Planning and Evaluation Report and the base case power flow data from the Eastern Interconnection Reliability Assessment Group Multiregional Modeling Working Group, which was used by NIPSCO for transmission planning; and FERC Form 730, which is NIPSCOs Report of Transmission Investment Activity. As a Transmission Owner subject to the MISO Transmission Owners Agreement and Tariff, NIPSCO has various FERC jurisdictional obligations such as maintaining its Attachment O formula rates and corresponding protocols. NIPSCO also has FERC approvals to make affiliate transactions between itself and various JVs. NIPSCOs officers, on the electric side, are also subject to FERCs interlocking directorate rules and reporting requirements. Regulatory Framework. The Gas Distribution Operations utilities have pursued non-traditional revenue sources within the evolving natural gas marketplace. These efforts include (i) the sale of products and services in the companies service territories, and (ii) gas supply cost incentive mechanisms for service to their core markets. The on-system services are offered by us to customers and include products such as the transportation and balancing of gas on the Gas Distribution Operations utility's system. The incentive mechanisms give the Gas Distribution Operations utilities an opportunity to share in the savings created from such situations as gas purchase prices paid below an agreed upon benchmark and their ability to reduce pipeline capacity charges with their customers. We recognize that energy efficiency reduces emissions, conserves natural resources and saves our customers money. Our gas distribution companies offer programs such as energy efficiency upgrades, home checkups and weatherization services. The increased efficiency of natural gas appliances and improvements in home building codes and standards contributes to a long-term trend of declining average use per customer. While we are looking to expand offerings so the energy efficiency programs can benefit as many customers as possible, our Gas Distribution Operations have pursued changes in rate design to more effectively match recoveries with costs incurred. Columbia of Ohio has adopted a straight fixed variable rate design that closely links the recovery of fixed costs with fixed charges. Columbia of Maryland and Columbia of Virginia have regulatory approval for weather and revenue normalization adjustments for certain customer classes, which adjust monthly revenues that exceed or fall short of approved levels. Columbia of Pennsylvania continues to operate its pilot residential weather normalization adjustment and also has a fixed customer charge. This weather normalization adjustment only adjusts revenues when actual weather compared to normal varies by more than 3%. Columbia of Kentucky incorporates a weather normalization adjustment for certain customer classes and also has a fixed customer charge. In a prior gas base rate proceeding, NIPSCO implemented a higher fixed customer charge for residential and small customer classes moving toward recovering more of its fixed costs through a fixed recovery charge, but has no weather or usage protection mechanism. While increased efficiency of electric appliances and improvements in home building codes and standards has similarly impacted the average use per electric customer in recent years, NIPSCO expects future growth in per customer usage as a result of increasing electric applications. Further growth is anticipated as electric vehicles become more prevalent. These ongoing changes in use of electricity will likely lead to development of innovative rate designs, and NIPSCO will continue efforts to design rates that increase the certainty of recovery of fixed costs. Cost Recovery and Trackers. Comparability of our line item operating results is impacted by regulatory trackers that allow for the recovery in rates of certain costs such as those described below. Increases in the expenses that are subject to approved regulatory tracker mechanisms generally lead to increased regulatory assets, which ultimately result in a corresponding increase in operating revenues and, therefore, have essentially no impact on total operating income results. Certain approved regulatory tracker mechanisms allow for abbreviated regulatory proceedings in order for the operating companies to quickly implement revised rates and recover associated costs. A portion of the Gas Distribution Operations revenue is related to the recovery of gas costs, the review and recovery of which occurs through standard regulatory proceedings. All states in our operating area require periodic review of actual gas ITEM 1. BUSINESS N I S OURCE I NC . procurement activity to determine prudence and confirm the recovery of prudently incurred energy commodity costs supplied to customers. A portion of the Electric Operations revenue is related to the recovery of fuel costs to generate power and the fuel costs related to purchased power. These costs are recovered through a FAC, which is updated quarterly to reflect actual costs incurred to supply electricity to customers. Environmental and Safety Matters PHMSA Regulations On December 27, 2020, the Protecting Our Infrastructure of Pipelines and Enhancing Safety (PIPES) Act of 2020 was signed into law, reauthorizing funding for federal pipeline safety programs through September 30, 2023. Among other things, the PIPES Act requires that PHMSA revise the pipeline safety regulations to require operators to update, as needed, their existing distribution integrity management plans, emergency response plans, and operation and maintenance plans. The PIPES Act also requires PHMSA to adopt new requirements for managing records and updating, as necessary, existing district regulator stations to eliminate common modes of failure that can lead to overpressurization. PHMSA must also require that operators implement and utilize advanced leak detection and repair technologies that enable the location and categorization of all leaks that are hazardous, or potentially hazardous, to human safety or the environment. Natural gas companies, including NiSource and our subsidiaries, may see increased costs depending on how PHMSA implements the new mandates resulting from the PIPES Act. Climate Change Issues Physical Climate Risks. Increased frequency of severe and extreme weather events associated with climate change could materially impact our facilities, energy sales, and results of operations. We are unable to predict these events. However, we perform ongoing assessments of physical risk, including physical climate risk, to our business. More extreme and volatile temperatures, increased storm intensity and flooding, and more volatile precipitation leading to changes in lake and river levels are among the weather events that are most likely to impact our business. Efforts to mitigate these physical risks continue to be implemented on an ongoing basis. Transition Climate Risks . Future legislative and regulatory programs, at both the federal and state levels, could significantly limit allowed GHG emissions or impose a cost or tax on GHG emissions. Revised or additional future GHG legislation and/or regulation related to the generation of electricity or the extraction, production, distribution, transmission, storage and end use of natural gas could materially impact our gas supply, financial position, financial results and cash flows. Regarding federal policies, we continue to monitor the implementation of any final and proposed climate change-related legislation and regulations, including the Infrastructure Investment and Jobs Act, signed into law in November 2021; the development of the Enhancement and Standardization of Climate-Related Disclosures, proposed by the SEC in March 2022; the IRA, signed into law in August 2022; and the EPA's proposed methane regulations for the oil and natural gas industry, but we cannot predict their impact on our business at this time. We have identified potential opportunities associated with the Infrastructure Investment and Jobs Act and the IRA and are evaluating how they may align with our strategy going forward. The energy-related provisions of the Infrastructure Investment and Jobs Act include new federal funding for power grid infrastructure and resiliency investments, new and existing energy efficiency and weatherization programs, electric vehicle infrastructure for public chargers and additional LIHEAP funding over the next five years. The IRA contains climate and energy provisions, including funding to decarbonize the electric sector. In February 2021, the United States rejoined the Paris Agreement, an international treaty through which parties set nationally determined contributions to reduce GHG emissions, build resilience, and adapt to the impacts of climate change. Subsequently, the Biden Administration released a target for the United States to achieve a 50%-52% GHG reduction from 2005 levels by 2030, which supports the President's goals to create a carbon-free power sector by 2035 and net zero emissions economy no later than 2050. There are many pathways to reach these goals. On June 30, 2022, the Supreme Court of the United States ruled for the petitioners in West Virginia v. EPA, which examined the authority of the EPA to regulate GHG emissions from the power sector. We will continue to evaluate this matter, but we remain committed to our previously stated carbon reduction goals. ITEM 1. BUSINESS N I S OURCE I NC . We also continue to monitor the implementation of any final and proposed state policy. The Virginia Clean Economy Act was signed into law in 2020. While the Act does not establish any new mandates on Columbia of Virginia, certain natural gas customers may, over the long-term, reduce their use of natural gas to meet the 100% renewable electricity requirement. Columbia of Virginia will continue to monitor this matter, but we cannot predict its final impact on our business at this time. Separately, the Virginia Energy Innovation Act, enacted into law in April 2022, and effective July 1, 2022, allows natural gas utilities to supply alternative forms of gas that meet certain standards and reduce emissions intensity. The Act also provides that the costs of enhanced leak detection and repair may be added to a utilitys plan to identify proposed eligible infrastructure replacement projects and related cost recovery mechanisms, known as the SAVE Plan. Furthermore, under the Act, utilities can recover eligible biogas supply infrastructure costs on an ongoing basis. The provisions of these laws may provide opportunities for Columbia of Virginia as it participates in the transition to a lower carbon future. The Climate Solutions Now Act of 2022 requires Maryland to reduce GHG emissions by 60% by 2031 (from 2006 levels), and it requires the state to reach net zero emissions by 2045. The Maryland Department of the Environment is required to adopt a plan to achieve the 2031 goal by December 2023, and it is required to adopt a plan for the net zero goal by 2030. The Act also enacts a state policy to move to broader electrification of both existing buildings and new construction, and requires the Public Service Commission to complete a study assessing the capacity of gas and electric distribution systems to successfully serve customers under a transition to a highly electrified building sector. Columbia of Maryland will continue to monitor this matter, but we cannot predict its final impact on our business at this time. NIPSCO, Columbia of Maryland, Columbia of Pennsylvania, Columbia of Virginia and Columbia of Kentucky each filed petitions to implement the Green Path Rider, which will be a voluntary rider that allows customers to opt in and offset either 50% or 100% of their natural gas related emissions. To reduce the emissions, the utilities will purchase RNG attributes and carbon offsets to match the usage for customers opting into the program. The program was approved by the IURC at NIPSCO in November 2022 with a January 2023 start date. After reaching settlement with other parties in September 2022, NIPSCO agreed to add a third tier to offset 25% of customer usage. Columbia of Marylands filing was denied by the PUC in January 2023. The filings for Columbia of Pennsylvania, Columbia of Virginia and Columbia of Kentucky are still being evaluated. Additionally, NIPSCO has a voluntary Green Power Rider program in place that allows customers to designate a portion or all their monthly electric usage to come from power generated by renewable energy sources. Net Zero Goal. In response to these transition risks and opportunities, on November 7, 2022, we announced a goal of net zero greenhouse gas emissions by 2040 covering both Scope 1 and Scope 2 emissions ("Net Zero Goal"). Our Net Zero Goal builds on greenhouse gas emission reductions achieved to-date and demonstrates that continued execution of our long-term business plan will drive further greenhouse gas emission reductions. We remain on track to achieve previously announced interim greenhouse gas emission reduction targets by reducing fugitive methane emissions from main and service lines by 50 percent from 2005 levels by 2025 and reducing Scope 1 greenhouse gas emissions from company-wide operations by 90 percent from 2005 levels by 2030. We plan to achieve our Net Zero Goal primarily through continuation and enhancement of existing programs, such as retiring and replacing coal-fired electric generation with low- or zero-emission electric generation, ongoing pipe replacement and modernization programs, and deployment of advanced leak-detection technologies. In addition, we plan to advance other low- or zero-emission energy resources and technologies, such as hydrogen, renewable natural gas, and/or deployment of carbon capture and utilization technologies, if and when these become technologically and economically feasible. Carbon offsets and renewable energy credits may also be used to support achievement of our Net Zero Goal. As of the end of 2021, we had reduced Scope 1 GHG emissions by approximately 58% from 2005 levels. Our greenhouse gas emissions projections, including achieving a Net Zero Goal, are subject to various assumptions that involve risks and uncertainties. Achievement of our Net Zero Goal by 2040 will require supportive regulatory and legislative policies, favorable stakeholder environments and advancement of technologies that are not currently economical to deploy. Should such regulatory and legislative policies, stakeholder environments or technologies fail to materialize, our actual results or ability to achieve our Net Zero Goal, including by 2040, may differ materially. As discussed in Management's Discussion within "Results and Discussion of Segment Operations - Electric Operations," NIPSCO continues to execute on an electric generation transition consistent with the preferred pathways identified in its 2018 and 2021 Integrated Resource Plans. Additionally, as discussed in Management's Discussion within "Liquidity and Capital Resources - Regulatory Capital Programs," our natural gas distribution companies are lowering methane emissions by replacing aging infrastructure, which also increases safety and reliability for customers and communities. Human Capital Human Capital Management Governance and Organizational Practices . The Compensation and Human Capital Committee of our Board of Directors (the "Board") is primarily responsible for assisting the Board in overseeing our human capital ITEM 1. BUSINESS N I S OURCE I NC . management practices. The Compensation and Human Capital Committee charter includes reviewing our human capital management function and programs, including related procedures, programs, policies and practices, and making recommendations to management with respect to equal employment opportunity and DEI initiatives, employee engagement and corporate culture, and talent management. In addition to overseeing our human capital management practices, in 2022 our Board was refreshed and is committed to ensuring that the Board is comprised of directors with diverse skills, expertise, experience and demographics, including racial and gender diversity. Women and people of color ("POC") each comprise 33% of our Board. Human Capital Goals and Objectives . We have aligned our human capital goals to achieve overall company strategic and operational objectives by driving an enhanced talent strategy, elevating support for front-line leaders, fostering a culture of rigor and accountability and strengthening our human resources function. We aspire to be an employer of choice in the utility industry through accelerating and embedding DEI throughout the enterprise and creating an enviable employee experience. Workforce Composition . As of

December 31, 2022, we had 7,117 full-time and 45 part-time active employees. Thirty-five percent of our employees were subject to collective bargaining agreements with various labor unions which expire between 2026 and 2027. Diversity, Equity and Inclusion . We are committed to accelerating and embedding DEI throughout the enterprise to reflect the communities and customers we serve. We have worked to develop diverse sourcing strategies to attract and increase our diverse representation. Our talent acquisition team hired 523 external candidates in 2022 across all business segments. Twenty-eight percent of external hires in 2022 were racially or ethnically diverse and 44% were female. In addition, we have focused on our implementation and development of programs to drive higher retention and engagement of our employees. Through our efforts, we have been able to increase participation in our Targeted Development for Diverse Talent program in 2022. Participants in this program are either female or POC. POC make up 49% of the participant population for 2022. In addition, we have implemented over 50 DEI programs with a strong emphasis on professional development and retention efforts within our seven Employee Resource Groups. We plan to post our 2022 consolidated EEO-1 report data on our website by the end of the first quarter of 2023. The following graph shows the percentage of total employees represented by gender overall and for our officers as of December 31, 2022: ITEM 1. BUSINESS N I S OURCE I NC . The following graph shows the percentage of total employees and officers represented by race/ethnicity as of December 31, 2022: Talent Attraction . To recruit and hire individuals with a variety of skills, talents, backgrounds and experiences, we value and cultivate relationships with the community and diverse outreach partners. We also target job fairs, including those focused on people of color, veterans and women candidates, and partner with local colleges and universities to identify and recruit qualified applicants in the communities we serve. We are focused on our future of work and creating a more flexible, agile model for roles that can be performed in a more remote setting to attract talent across our footprint. In 2022, we introduced a hybrid-working model, which recognizes differing ways of working: onsite, hybrid and remote. As of December 31, 2022, 58% of our workforce is onsite, 35% are hybrid and 7% are remote. This new working model supports colleague connection, development and mentoring as well as broader team building. Talent Development and Retention . We offer leadership development programs to enhance the behaviors and skills of our existing and future leaders. In 2022, we had participation from employees at all levels in our extensive technical and non-technical employee leadership development training programs. We strive to provide promotion and advancement opportunities for employees. In 2022, for all leadership positions at the supervisor and above level posted externally, we filled 69% with internal employees. We develop and implement targeted development action plans to increase succession candidate readiness for leadership roles. Additionally, we monitor the risk and potential impact of talent loss and take action to increase retention of top talent. Retention in 2022 was over 91%. We calculate retention as the total number of separations divided by the average headcount for the annual period. These separations include involuntary separation (2%), resignation (5%), and retirement (2%). Executive Succession Planning . We perform succession planning quarterly for officer level positions to ensure that we develop and sustain a strong bench of talent capable of performing at the highest levels. Talent is identified, and potential paths of development are discussed to ensure that employees have an opportunity to build their skills and are well-prepared for future roles. We maintain formal succession plans for our Chief Executive Officer ("CEO") and key executive officers. The succession plan for our CEO is reviewed by the Environmental, Social, Nominating and Governance Committee of the Board and the succession plans for executive officers (other than the CEO) and other critical roles are reviewed by the Compensation and Human Capital Committee annually or more frequently as needed. ITEM 1. BUSINESS N I S OURCE I NC . Employee and Workplace Health and Safety . We have several programs to support employees, and their families physical, mental, and financial well-being. These programs include a paid wellness day, telemedicine services, an Employee Assistance Program, Integrated Health Management navigation services, employee paid sick/disability leave, parental leave, and paid illness in family days. We also offer competitive medical, dental, vision, life and long-term disability programs, including employee health savings account company contributions. We have a robust program to support employee, contractor and public safety, which is led by our Chief Safety Officer and is overseen by the Safety, Operations, Regulatory and Policy Committee of our Board. As we will outline in our annual safety report on our corporate website, we continue to invest in risk reduction activities and assets . Culture and Engagement. Our culture is another important aspect of our ability to advance our strategic and operational objectives. In addition to our DEI, recruiting, development and retention programs described above, we also invest in internal communications programs, including in-person and virtual learning and networking opportunities, as well as regular town hall communications with employees. We measure and monitor culture and employee engagement through a variety of channels including employee lifecycle, pulse, and census surveys. To instill and reinforce our values and culture, we require our employees to participate in regular trainings on ethics and compliance topics each year, including raising concerns, treating others with respect, preventing discrimination in the workplace, anti-bribery and corruption, data protection, unconscious biases, harassment, conflicts of interest, and how to use the anonymous ethics and compliance hotline. All employees receive training on our Code of Business Conduct biannually or more frequently if there is a material change in content. Our business ethics program, including the employee training program, is reviewed annually by our executive leadership team and the Audit Committee of our Board. Our Compensation and Human Capital Committee reviews reports from our Chief Human Resources Officer and Chief Diversity, Equity and Inclusion Officer on employee engagement and corporate culture. Our Board reviews results and action plans related to our enterprise-wide comprehensive employee engagement survey. Our executive leadership team, including our Chief Executive Officer, communicates directly and regularly with all employees on timely ethics topics through electronic messages, coffee chats, and all-employee town hall meetings. These communications emphasize the importance of our values and culture in the workplace. Other Relevant Business Information Our customer base is broadly diversified, with no single customer accounting for a significant portion of revenues. For a listing of material subsidiaries of NiSource, refer to Exhibit 21. We electronically file various reports with the SEC, including annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to such reports, as well as our proxy statements for the Company's annual meetings of stockholders at http://www.sec.gov . Additionally, we make all SEC filings available without charge to the public on our web site at http://www.nisource.com . The information contained on our website is not included in, nor incorporated by reference into, this Annual Report on Form 10-K. INFORMATION ABOUT OUR EXECUTIVE OFFICERS N I S OURCE I NC . The following is a list of our Executive Officers, including their names, ages, offices held and other recent business experience. ##TABLE_START Name Age Office(s) Held in Past 5 Years Lloyd M. Yates 62 President and Chief Executive Officer Executive Vice President, Customer and Delivery Operations, and President, Carolinas Region, of Duke Energy Corporation from 2014 to 2019. Donald E. Brown 51 Executive Vice President and Chief Financial Officer Executive Vice President of NiSource since May 2015. Chief Financial Officer of NiSource since July 2015. President, NiSource Corporate Services since June 2020. Melody Birmingham 51 Executive Vice President, Chief Innovation Officer Senior Vice President and Chief Administrator Officer of Duke Energy Corporation from May 2021 to June 2022. Senior Vice President, Supply Chain and Chief Procurement Officer of Duke Energy Corporation from November 2018 to April 2021. President of Duke Energy Corporation from June 2015 to November 2018 William Jefferson, Jr 61 Executive Vice President, Operations and Chief Safety Officer Station Director and Vice President at STPNOC, Wadsworth, Texas, from 2016 to May 2022. Shawn Anderson 41 Senior Vice President,Strategy and Chief Risk Officer Vice President, Strategy of NiSource from January 2019 to May 2020. Vice President of NiSource from May 2018 to December 2018. Treasurer and Chief Risk Officer of NiSource from June 2016 to December 2018. Kimberly S. Cuccia 39 Senior Vice President, General Counsel and Corporate Secretary Vice President General Counsel, Interim Corporate Secretary of NiSource from January 2022 to March 2022. Vice President and Deputy General Counsel, Regulatory, of NiSource Corporate Services Company, from January 2021 to December 2021. Vice President and General Counsel, Columbia Gas of Massachusetts, NiSource Corporate Services Company, from October 2019 to December 2020. Vice President and General Counsel, Massachusetts Restoration, NiSource Corporate Services Company, from October 2018 to October 2019. Chief Counsel, Columbia Gas Companies from June 2015 to September 2018. Melanie B. Berman 52 Senior Vice President and Chief Human Resources Officer Executive Vice President and Chief Human Resources Officer of The Michaels Companies, Inc. from 2020 to 2021. Vice President, Human Resources of Anthem, Inc. from January 2018 to 2019. ##TABLE_END ITEM 1A. RISK FACTORS N I S OURCE I

Ticker: NI, Sector: Utilities, Filed At: 2023-02-22T16:23:21-05:00

NC . Our operations and financial results are subject to various risks and uncertainties, including those described below, that could adversely affect our business, financial condition, results of operations, cash flows, and the market price of our common stock. OPERATIONAL RISKS We may not be able to complete the sale of a minority interest in NIPSCO on the expected timeline or at all. On November 7, 2022, we announced our intention to sell a minority interest in NIPSCO (the NIPSCO Minority Interest Sale). We intend to evaluate various alternatives to determine the optimal transaction structure to maximize stakeholder value as a result of the NIPSCO Minority Interest Sale. A successful sale will be dependent on factors such as regulatory approval(s) and negotiations with one or more counterparties. There can be no assurances that we will be able to successfully complete the NIPSCO Minority Interest Sale on the anticipated timeline or at all. Furthermore, there can be no assurances that the NIPSCO Minority Interest Sale will lead to the anticipated benefits to stockholders. We may not be able to execute our business plan or growth strategy, including the NIPSCO Minority Interest Sale and utility infrastructure investments. Business or regulatory conditions may result in our inability to execute our business plan or growth strategy, including the NIPSCO Minority Interest Sale and identified, planned and other utility infrastructure investments, which includes investments related to natural gas pipeline modernization and our renewable energy projects, and the build-transfer execution goals within our business plan. Our Enterprise Transformation Roadmap initiatives are designed to identify long-term sustainable capability enhancements, cost optimization improvements, technology investments and work process optimization, has increased the volume and pace of change and may not be effective as it continues. Our customer and regulatory initiatives may not achieve planned results. Utility infrastructure investments may not materialize, may cease to be achievable or economically viable and may not be successfully completed. Natural gas may cease to be viewed as an economically and environmentally attractive fuel. Certain environmental activist groups, investors and governmental entities continue to oppose natural gas delivery and infrastructure investments because of perceived environmental impacts associated with the natural gas supply chain and end use. Energy conservation, energy efficiency, distributed generation, energy storage, policies favoring electric heat over gas heat and other factors may reduce demand for natural gas and electricity. In addition, we consider acquisitions or dispositions of assets or businesses, JVs, including in connection with the NIPSCO Minority Interest Sale, and mergers from time to time as we execute on our business plan and growth strategy. Any of these circumstances could adversely affect our results of operations and growth prospects. Even if our business plan and growth strategy are executed, there is still risk of, among other things, human error in maintenance, installation or operations, shortages or delays in obtaining equipment, including as a result of transportation delays and availability, labor availability and performance below expected levels (in addition to the other risks discussed in this section). We are currently experiencing, and expect to continue to experience, supply chain challenges, including labor availability issues, impacting our ability to obtain materials for our gas and electric projects. Risks to our capital projects, including risks related to supply chain challenges and labor availability, are described in a separate risk factor below. Our gas distribution and transmission activities, as well as generation, transmission and distribution of electricity, involve a variety of inherent hazards and operating risks, including potential public safety risks. Our gas distribution and transmission activities, as well as generation, transmission and distribution of electricity, involve a variety of inherent hazards and operating risks, including, but not limited to, gas leaks and over-pressurization, downed power lines, stray electrical voltage, excavation or vehicular damage to our infrastructure, outages, environmental spills, mechanical problems and other incidents, which could cause substantial financial losses, as demonstrated in part by the Greater Lawrence Incident. We also have distribution propane assets that involve similar risks. In addition, these hazards and risks have resulted and may result in the future in serious injury or loss of life to employees and/or the general public, significant damage to property, environmental pollution, impairment of our operations, adverse regulatory rulings and reputational harm, which in turn could lead to substantial losses for NiSource and its stockholders. The location of pipeline facilities, including regulator stations, liquefied natural gas and underground storage, or generation, transmission, substation and distribution facilities near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from such incidents. As with the Greater Lawrence Incident, certain incidents have subjected and may in the future subject us to both civil and criminal litigation or administrative or other legal proceedings from time to time, which could result in substantial monetary judgments, fines, or penalties against us, be resolved on unfavorable terms, and require us to incur significant operational expenses. The occurrence of incidents has in certain instances adversely affected and could in the ITEM 1A. RISK FACTORS N I S OURCE I NC . future adversely affect our reputation, cash flows, financial position and/or results of operations. We maintain insurance against some, but not all, of these risks and losses. We may conduct certain operations, including in connection with the NIPSCO Minority Interest Sale, through a JV arrangement involving third-party investors that may result in delays, litigation or operational impasses. We may enter into JV arrangements involving third-party investors, including in connection with the NIPSCO Minority Interest Sale. As part of a JV arrangement, third-party investors may hold certain protective rights that may impact our ability to make certain decisions. Any such third-party investors may have interests and objectives which may differ from ours and, accordingly, disputes may arise that may result in delays, litigation or operational impasses. Failure to adapt to advances in technology and manage the related costs could make us less competitive and negatively impact our results of operations and financial condition. A key element of our electric business model includes generating power at central station power plants to achieve economies of scale and produce power at a competitive cost. We continue to transition our generation portfolio in order to implement new and diverse technologies including renewable energy, distributed generation, energy storage, and energy efficiency designed to reduce regulated emissions. Advances in technology and potential competition supported by changes in laws or regulations could reduce the cost of electric generation and provide retail alternatives causing power sales to decline and the value of our generating facilities to decline. Our natural gas business model depends on widespread utilization of natural gas for space heating as a core driver of revenues. Alternative energy sources, new technologies or alternatives to natural gas space heating, including cold climate heat pumps and/or efficiency of other products, could reduce demand and increase customer attrition, which could impact our ability to recover on our investments in our gas distribution assets. Our future success will depend, in part, on our ability to anticipate and successfully adapt to technological changes, to offer services that meet customer demands and evolving industry standards, including environmental impacts associated with our products and services, and to recover all, or a significant portion of, remaining investments in retired assets. A failure by us to effectively adapt to changes in technology and manage the related costs could harm the ability of our products and services to remain competitive in the marketplace and could have a material adverse impact on our results of operations and financial condition. Aging infrastructure may lead to disruptions in operations and increased capital expenditures and maintenance costs, all of which could negatively impact our financial results. We have risks associated with aging electric and gas infrastructure. These risks can be driven by threats such as, but not limited to, electrical faults, mechanical failure, internal corrosion, external corrosion, ground movement and stress corrosion and/or cracking. The age of these assets may result in a need for replacement, a higher level of maintenance costs or unscheduled outages, despite efforts by us to properly maintain or upgrade these assets through inspection, scheduled maintenance and capital investment. In addition, the nature of the information available on aging infrastructure assets, which in some cases is incomplete, may make the operation of the infrastructure, inspections, maintenance, upgrading and replacement of the assets particularly challenging. Missing or incorrect infrastructure data may lead to (1) difficulty properly locating facilities, which can result in excavator damage and operational or emergency response issues, and (2) configuration and control risks associated with the modification of system operating pressures in connection with turning off or turning on service to customers, which can result in unintended outages or operating pressures. Also, additional maintenance and inspections are required in some instances to improve infrastructure information and records and address emerging regulatory or risk management requirements, resulting in increased costs. Supply chain issues related to shortages of materials and transportation logistics may lead to delays in the maintenance and replacement of aging infrastructure, which could increase the probability and/or impact of a public safety incident. We lack diversity in suppliers of some gas materials. While we have implemented contractual protections with suppliers and stockpile some materials in inventory for such supply risks, we may not be effective in ensuring that we can obtain adequate emergency supply on a timely basis in each state, that no compromises are being made on quality and that we have alternate suppliers available. The failure to operate our assets as desired could result in interruption of electric service, major component failure at generating facilities and electric substations, gas leaks and other incidents, and an inability to meet firm service and compliance ITEM 1A. RISK FACTORS N I S OURCE I NC . obligations, which could adversely impact revenues, and could also result in increased capital expenditures and maintenance costs, which, if not fully recovered from customers, could negatively impact our financial results. We may be unable to obtain insurance on acceptable terms or at all, and the insurance coverage we do obtain may not provide protection against all significant losses. Our ability to obtain insurance, as well as the cost and coverage of such insurance, are affected by developments affecting our business; international, national, state, or local events; and the financial condition and underwriting considerations of insurers. For example, some insurers are moving away from underwriting certain carbon-intensive energy-related businesses such as those in the coal industry or those exposed to specific perils such as wildfires as well as gas explosion events or other infrastructure-related or natural catastrophe risks. The utility insurance market continues to be impacted by a prevalence of severe losses, and despite significant annual increases in rates over the past few years, markets are experiencing unacceptable loss ratios. Certain perils, such as cyber, are now being excluded from some master policies for property and casualty insurance, requiring procurement of additional policies to be obtained to maintain consistent coverage at an additional cost. Capacity limits insurers are willing to issue have decreased, requiring participation from more insurers to provide adequate coverage. Insurance coverage may not continue to be available at limits, rates or terms acceptable to us. In addition, our insurance is not sufficient or effective under all circumstances and against all hazards or liabilities to which we are subject. Certain types of damages, expenses or claimed costs, such as fines and penalties, have been and in the future may be excluded under the policies. In addition, insurers providing insurance to us may raise defenses to coverage under the terms and conditions of the respective insurance policies that could result in a denial of coverage or limit the amount of insurance proceeds available to us. Any losses for which we are not fully insured or that are not covered by insurance at all could materially adversely affect our results of operations, cash flows and financial position. Aspects of the implementation of our electric generation strategy, including the retirement of our coal generation units, may be delayed and may not achieve intended results. As discussed in Results and Discussion of Segment Operations - Electric Operations, in Managements Discussion and Analysis of Financial Condition and Results of Operations, our 2018 Integrated Resource Plan (2018 Plan) outlines the path to retire the remaining two coal units at R.M. Schahfer by the end of 2025 and the remaining coal-fired generation by the end of 2028, to be replaced by lower-cost, reliable and cleaner options. Our 2021 Integrated Resource Plan (2021 Plan) validated the activities underway pursuant to our 2018 Plan and calls for the retirement of the Michigan City Generating Station, replacement of existing vintage gas peaking units at the R.M.

Schahfer Generating Station and upgrades to the transmission system to enhance our electric generation transition. Recent developments, including macro supply chain issues and U.S. federal policy actions, have created significant uncertainty around the availability of key input material necessary to develop and place our renewable energy projects in service. In the U.S., solar industry supply chain issues include the pending U.S. Department of Commerce investigation on Antidumping and Countervailing Duties Anti Circumvention Petition filed by a domestic solar manufacturer (the DOC Investigation), the Uyghur Forced Labor Protection Act, Section 201 Tariffs and persistent general global supply chain and labor availability issues. The most prominent effect of these issues is the significant curtailment of imported solar panels and other key components required to complete utility scale solar projects in the U.S. Any available solar panels may not meet the cost and efficiency standards of our currently approved projects and the incremental cost may not be recoverable through customer rates. As a result of the challenges in obtaining solar panels, many solar projects in the U.S. have been delayed or canceled. As we are in the midst of a transition to an electric generation portfolio with more renewable resources, including solar, our projects are subject to the effects of these issues. Our expectation has been that solar energy sources would be one of the primary ways in which we will meet our electric generation capacity and reliability obligations to the MISO market and reliably serve our customers when we retire our coal generation capacity. The high level of uncertainty surrounding the completion of our solar renewable energy projects creates significant risks for us to reliably meet our capacity and energy obligations to MISO and to provide reliable and affordable energy to our customers. Any additional delays to the completion dates of our ten planned and approved solar projects are expected to impact our capacity position and our ability to meet our resource adequacy obligations to MISO. Delays to the completion dates of our projects could also include delays in the financial return of certain investments and impact the overall timing of our electric generation transition. As noted above, we expect our electric generation strategy to require additional investment to meet our MISO obligations and may require significant future capital expenditures, operating costs and charges to earnings that may negatively impact our financial position, financial results and cash flows. An inability to secure and deliver on renewable projects is negatively ITEM 1A. RISK FACTORS N I S OURCE I NC . impacting our generation transition timeline and may negatively impact our achievement of decarbonization goals and reputation. Our capital projects and programs subject us to construction risks and natural gas costs and supply risks, and are subject to regulatory oversight, including requirements for permits, approvals and certificates from various governmental agencies. Our business requires substantial capital expenditures for investments in, among other things, capital improvements to our electric generating facilities, electric and natural gas distribution infrastructure, natural gas storage and other projects, including projects for environmental compliance. As we undertake these projects and programs, we may be unable to complete them on schedule or at the anticipated costs due in part to shortages in materials as described more fully below.

Additionally, we may construct or purchase some of these projects and programs to capture anticipated future growth, which may not materialize, and may cause the construction to occur over an extended period of time. Our existing and planned capital projects require numerous permits, approvals and certificates from federal, state, and local governmental agencies. If there is a delay in obtaining any required regulatory approvals or if we fail to obtain or maintain any required approvals or to comply with any applicable laws or regulations, we may not be able to construct or operate our facilities, we may be forced to incur additional costs or we may be unable to recover any or all amounts invested in a project. We also may not receive the anticipated increases in revenue and cash flows resulting from such projects and programs until after their completion. Other construction risks include changes in the availability and costs of materials, equipment, commodities or labor (including changes to tariffs on materials), delays caused by construction incidents or injuries, work stoppages, shortages in qualified labor, poor initial cost estimates, unforeseen engineering issues, the ability to obtain necessary rights-of-way, easements and transmissions connections and general contractors and subcontractors not performing as required under their contracts. We are monitoring risks related to increasing order and delivery lead times for construction and other materials, increasing risk associated with the unavailability of materials due to global shortages in raw materials and issues with transportation logistics, and risk of decreased construction labor productivity in the event of disruptions in the availability of materials critical to our gas and electric operations. Our efforts to enhance our resiliency to supply chain shortages may not be effective. We are also seeing increasing prices associated with certain materials, equipment and products, which impacts our ability to complete major capital projects at the cost that was planned and approved. To the extent that delays occur or costs increase, customer affordability as well as our business operations, results of operations, cash flows and financial condition could be materially adversely affected. In addition, to the extent that delays occur on projects that target system integrity, the risk of an operational incident could increase. For more information on global availability of materials for our renewable projects, see - Results and Discussion of Segment Operations - Electric Operations - Electric Supply and Generation Transition. To the extent that delays occur, costs become unrecoverable or recovery is delayed, or we otherwise become unable to effectively manage and complete our capital projects, our results of operations, cash flows, and financial condition may be adversely affected. A significant portion of the gas and electricity we sell is used by residential and commercial customers for heating and air conditioning. Accordingly, fluctuations in weather, gas and electricity commodity costs, inflation and economic conditions impact demand of our customers and our operating results. Energy sales are sensitive to variations in weather. Forecasts of energy sales are based on normal weather, which represents a long-term historical average. Significant variations from normal weather resulting from climate change or other factors could have, and have had, a material impact on energy sales. Additionally, residential usage, and to some degree commercial usage, is sensitive to fluctuations in commodity costs for gas and electricity, whereby usage declines with increased costs, thus affecting our financial results. Commodity prices have been and may continue to be volatile. Rising gas costs could heighten regulator and stakeholder sensitivity relative to the impact of base rate increases on customer affordability. Lastly, residential and commercial customers usage is sensitive to economic conditions and factors such as recession, inflation, unemployment, consumption and consumer confidence. Therefore, prevailing economic conditions affecting the demand of our customers may in turn affect our financial results. Fluctuations in the price of energy commodities or their related transportation costs or an inability to obtain an adequate, reliable and cost-effective fuel supply to meet customer demands may have a negative impact on our financial results. ITEM 1A. RISK FACTORS N I S OURCE I NC . Our current electric generating fleet is dependent on coal and natural gas for fuel, and our gas distribution operations purchase and resell a portion of the natural gas we deliver to our customers. These energy commodities are subject to price fluctuations and fluctuations in associated transportation costs. We use physical hedging through the use of storage assets and use financial products in certain jurisdictions in order to offset fluctuations in commodity supply prices. We rely on regulatory recovery mechanisms in the various jurisdictions in order to fully recover the commodity costs incurred in selling energy to our customers. However, while we have historically been successful in the recovery of costs related to such commodity prices, there can be no assurance that such costs will be fully recovered through rates in a timely manner. In addition, we depend on electric transmission lines, natural gas pipelines, and other transportation facilities owned and operated by third parties to deliver the electricity and natural gas we sell to wholesale markets, supply natural gas to our gas storage and electric generation facilities, and provide retail energy services to our customers. If transportation is disrupted, if capacity is inadequate or if supply is interrupted due to issues at the wellhead, we may be unable to sell and deliver our gas and electric services to some or all of our customers. As a result, we may be required to procure additional or alternative electricity and/or natural gas supplies at then-current market rates, which, if recovery of related costs is disallowed, could have a material adverse effect on our businesses, financial condition, cash flows, results of operations and/or prospects. Failure to attract and retain an appropriately qualified workforce, and maintain good labor relations, could harm our results of operations. We operate in an industry that requires many of our employees and contractors to possess unique technical skill sets. An aging workforce without appropriate replacements, the mismatch of skill sets to future needs, the unavailability of talent for internal positions and the unavailability of contract resources may lead to operating challenges or increased costs. These operating challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. For example, certain skills, such as those related to construction, maintenance and repair of transmission and distribution systems, are in high demand and have a limited supply. Current and prospective employees may determine that they do not wish to work for us due to market, economic, employment and other conditions, including those related to organizational changes as described in the risk factor below. We face increased competition for talent in the current environment of sustained labor shortage and increased turnover rates. Incidents of any pandemic in our workforce could increase the risk of worker illness and availability. These or other employee workforce factors could negatively impact our business, financial condition or results of operations. A significant portion of our workforce is subject to collective bargaining agreements. Our collective bargaining agreements are generally negotiated on an operating company basis with some companies having multiple bargaining agreements, which may span different geographies. Any failure to reach an agreement on new labor contracts or to renegotiate these labor contracts might result in strikes, boycotts or other labor disruptions. Our workforce continuity plans may not be effective in avoiding work stoppages that may result from labor negotiations or mass resignations. Labor disruptions, strikes or significant negotiated wage and benefit increases, whether due to union activities, employee turnover or otherwise, could have a material adverse effect on our businesses, results of operations and/or cash flows. Our strategic plan includes enhanced technology and transmission and distribution investments and a reduction in reliance on coal-fired generation. As part of our strategic plan, we will need to attract and retain personnel that are qualified to implement our strategy and may need to retrain or re-skill certain employees to support our long-term objectives. Failure to hire and retain qualified employees, including the ability to transfer significant internal historical knowledge and expertise to the new employees, may adversely affect our ability to manage and operate our business. If we are unable to successfully attract and retain an appropriately qualified workforce and maintain satisfactory collective bargaining agreements, safety, service reliability, customer satisfaction and our results of operations could be adversely affected. If we cannot effectively manage new initiatives and organizational changes, we will be unable to address the opportunities and challenges presented by our strategy and the business and regulatory environment. In order to execute on our sustainable growth strategy and enhance our culture of ongoing continuous improvement, we must effectively manage the complexity and frequency of new initiatives and organizational changes. The organizational changes from our transformation initiatives have put short-term pressure on employees due to the volume and pace of change and, in some cases, loss of personnel. Front-line workers are being impacted by the variety of process and technology changes that are currently in progress. ITEM 1A. RISK FACTORS N I S OURCE I NC . If we are unable to make decisions quickly, assess our opportunities and risks, and successfully implement new governance, managerial and organizational processes as needed to execute our strategy in this increasingly dynamic and competitive business and regulatory environment, our financial condition, results of operations and relationships with our business partners, regulators, customers, employees and stockholders may be negatively impacted. Actions of activist stockholders could negatively affect our business and stock price and cause us to incur significant expenses. We may be subject to actions or proposals from activist stockholders or others that may not be aligned with our long-term strategy or the interests of our other stockholders. We have had communications with an activist stockholder. Our response to suggested actions, proposals, director nominations and contests for the election of directors by activist stockholders could disrupt our business and operations, divert the attention of our board of directors, management and employees and be costly and timeconsuming. Potential actions by activist stockholders or others may interfere with our ability to execute our strategic plans; create perceived uncertainties as to the future direction of our business or strategy; cause uncertainty with our regulators; make it more difficult to attract and retain qualified personnel; and adversely affect our relationships with our existing and potential business partners. Any of the foregoing could adversely affect our business, financial condition and results of operations. Also, we may be required to incur significant fees and other expenses related to responding to stockholder activism, including for third-party advisors. Moreover, our stock price could be subject to significant fluctuation or otherwise be adversely affected by the events, risks and uncertainties of any stockholder activism. We outsource certain business functions to third-party suppliers and service providers, and substandard performance by those third parties could harm our business, reputation and results of operations. Utilities rely on extensive networks of business partners and suppliers to support critical enterprise capabilities across their organizations. Like other companies in the utilities industry, we are seeing slowing deliveries from suppliers and in some cases materials and labor shortages for capital projects. We outsource certain services to third parties in areas including construction services, information technology, materials, fleet, environmental, operational services, corporate and other areas. In addition to delays and unavailability at times, outsourcing of services to third parties could expose us to inferior service quality or substandard deliverables, which may result in non-compliance (including with applicable legal requirements and industry standards), interruption of service or accidents or reputational harm, which could negatively impact our results of operations. We do not have full visibility into our supply chain, which may impact our ability to serve customers in a safe, reliable and cost-effective manner. These risks include the risk of operational failure, reputation damage, disruption due to new supply chain disruptions, exposure to significant commercial losses and fines and poorly positioned and distressed suppliers. If we continue to see delayed deliveries and shortages or if any other difficulties in the operations of these third-party suppliers and service providers, including their systems, were to occur, they could adversely affect our results of operations, or adversely affect our ability to work with regulators, unions, customers or employees. A cyber-attack on any of our or certain third-party technology systems upon which we rely may adversely affect our ability to operate and could lead to a loss or misuse of confidential and proprietary information or potential liability. We are reliant on technology to run our business, which is dependent upon financial and operational technology systems to process critical information necessary to conduct various elements of our business, including the generation, transmission and distribution of electricity; operation of our gas pipeline facilities; and the recording and reporting of commercial and financial transactions to regulators, investors and other stakeholders. In addition to general information and cyber risks that all large corporations face (e.g., ransomware, malware, unauthorized access attempts, phishing attacks, malicious intent by insiders, third-party software vulnerabilities and inadvertent disclosure of sensitive information), the utility industry faces evolving and increasingly complex cybersecurity risks associated with protecting sensitive and confidential customer and employee information, electric grid infrastructure, and natural gas infrastructure. Deployment of new business technologies, along with maintaining legacy technology, represents a large-scale opportunity for attacks on our information systems and confidential customer and employee information, as well as on the integrity of the energy grid and the natural gas infrastructure. Additionally, the conflict between Russia and Ukraine, as well as increased surveillance activity from China, has increased the likelihood of a cyber-attack on critical infrastructure systems. Increasing large-scale corporate attacks in conjunction with more sophisticated threats continue to challenge power and utility companies. Any failure of our technology systems, or those of our customers, suppliers or others with whom we do business, ITEM 1A. RISK FACTORS N I S OURCE I NC . could materially disrupt our ability to operate our business and could result in a financial loss and possibly do harm to our reputation. Additionally, our information systems experience ongoing, often sophisticated, cyber-attacks by a variety of sources, including foreign sources, with the apparent aim to breach our cyber-defenses. While we have implemented and maintain a cybersecurity program designed to protect our information technology, operational technology, and data systems from such attacks, our cybersecurity program does not prevent all breaches or cyberattack incidents. We have experienced an increase in the number of attempts by external parties to access our networks or our company data without authorization. We have experienced, and expect to continue to experience, cyber intrusions and attacks to our information systems and our operational technology. To our knowledge, none of these intrusions or attacks have resulted in a material cybersecurity intrusion or data breach. The risk of a disruption or breach of our operational technology, or the compromise of the data processed in connection with our operations, through cybersecurity breach or ransomware attack has increased as attempted attacks have advanced in sophistication and number around the world. Technological complexities combined with advanced cyber-attack techniques, lack of cyber hygiene and human error can result in a cybersecurity incident, such as a ransomware attack. Supplier non-compliance with cyber controls can also result in a cybersecurity incident. Attacks can occur at any point in the supply chain or with any suppliers. In addition, unmanned aircraft systems (UAS) or drones are used for various commercial and recreational purposes across the country. The Cybersecurity Infrastructure Security Agency (CISA) released alerts pertaining to UASs being used for malicious activities and the cybersecurity risk is continuing to increase. In addition, we collect and retain personally identifiable information of our customers, stockholders and employees. Customers, stockholders and employees expect that we will adequately protect their personal information. The regulatory environment surrounding information security and privacy is increasingly demanding. Although we attempt to maintain adequate defenses to these attacks and work through industry groups and trade associations to identify common threats and assess our countermeasures, a security breach of our information systems and/or operational technology, or a security breach of the information systems of our customers, suppliers or others with whom we do business, could (i) adversely impact our ability to safely and reliably deliver electricity and natural gas to our customers through our generation, transmission and distribution systems and potentially negatively impact our compliance with certain mandatory reliability and gas flow standards, (ii) subject us to reputational and other harm or liabilities associated with theft or inappropriate release of certain types of information such as system operating information or information, personal or otherwise, relating to our customers or employees, (iii) impact our ability to manage our businesses, and/or (iv) subject us to legal and regulatory proceedings and claims from third parties, in addition to remediation costs, any of which, in turn, could have a material adverse effect on our businesses, cash flows, financial condition, results of operations and/or prospects. Although we do maintain cyber insurance, it is possible that such insurance will not adequately cover any losses or liabilities we may incur as a result of a cybersecurity incident. Compliance with and changes in cybersecurity requirements have a cost and operational impact on our business, and failure to comply with such laws and regulations could adversely impact our reputation, results of operations, financial condition and/or cash flows. As cyber-attacks are becoming more sophisticated, U.S. government warnings have indicated that critical infrastructure assets, including pipelines and electric infrastructure, may be specifically targeted by certain groups. In 2021, the Transportation Security Administration (TSA) announced two new security directives in response to a ransomware attack on the Colonial Pipeline that occurred earlier in the year. These directives require critical pipeline owners to comply with mandatory reporting measures, designate a cybersecurity coordinator, provide vulnerability assessments, and ensure compliance with certain cybersecurity requirements. Such directives or other requirements may require expenditure of significant additional resources to respond to cyberattacks, to continue to modify or enhance protective measures, or to assess, investigate and remediate any critical infrastructure security vulnerabilities. Additionally, on November 30, 2022, the TSA issued an advance notice of proposed rulemaking (ANPRM) seeking public comment on more comprehensive, formal cybersecurity regulations for the pipeline industry. Any failure to comply with such government regulations or failure in our cybersecurity protective measures may result in enforcement actions that may have a material adverse effect on our business, results of operations and financial condition. In addition, there is no certainty that costs incurred related to securing against threats will be recovered through rates. The impacts of natural disasters, acts of terrorism, acts of war, civil unrest, cyber-attacks, accidents, public health emergencies or other catastrophic events may disrupt operations and reduce the ability to service customers. ITEM 1A. RISK FACTORS N I S OURCE I NC . A disruption or failure of natural gas distribution systems, or within electric generation, transmission or distribution systems, in the event of a major hurricane, tornado, or other major weather event, or terrorist attack, acts of war, including the political and economic disruption and uncertainty related to Russias military invasion of Ukraine, civil unrest, cyber-attack (as further detailed above), accident, public health emergency, pandemic, or other catastrophic event could cause delays in completing sales, providing services, or performing other critical functions. We have experienced disruptions in the past from hurricanes and tornadoes and other events of this nature. Also, companies in our industry face a heightened risk of exposure to and have experienced acts of terrorism and vandalism. Our electric and gas physical infrastructure may be targets of physical security threats or terrorist activities that could disrupt our operations. We have increased security given the current environment and may be required by regulators or by the future threat environment to make investments in security that we cannot currently predict. In addition, the supply chain constraints that we are experiencing could impact timely restoration of services. The occurrence of such events could adversely affect our financial position and results of operations. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. We are exposed to significant reputational risks, which make us vulnerable to a loss of cost recovery, increased litigation and negative public perception. As a utility company, we are subject to adverse publicity focused on the reliability of our services, the speed with which we are able to respond effectively to electric outages, natural gas leaks or events and related accidents and similar interruptions caused by storm damage, physical or cyber security incidents, or other unanticipated events, as well as our own or third parties actions or failure to act. We are subject to prevailing labor markets and potential high attrition, which may impact the speed of our customer service response. We are also facing supply chain challenges, the impacts of which may adversely impact our reputation in several areas as described elsewhere in these risk factors. We are also subject to adverse publicity related to actual or perceived environmental impacts. If customers, legislators or regulators have or develop a negative opinion of us, this could result in less favorable legislative and regulatory outcomes or increased regulatory oversight, increased litigation and negative public perception. The adverse publicity and investigations we experienced as a result of the Greater Lawrence Incident may have an ongoing negative impact on the publics perception of us. It is difficult to predict the ultimate impact of this adverse publicity. The foregoing may have continuing adverse effects on our business, results of operations, cash flow and financial condition. The physical impacts of climate change and the transition to a lower carbon future are impacting our business and could materially adversely affect our results of operations. Climate change is exacerbating risks to our physical infrastructure by increasing the frequency of extreme weather, including heat stresses to power lines, cold temperature stress to our electric and gas systems, and storms and floods that damage infrastructure. In addition, climate change is likely to cause lake and river level changes that affect the manner in which services are currently provided and droughts or other limits on water used to supply services, and other extreme weather conditions. We have adapted and will continue to evolve our infrastructure and operations to meet current and future needs of our stakeholders. With higher frequency of these and other possible extreme weather events it may become more costly for us to safely and reliably deliver certain products and services to our customers. Some of these costs may not be recovered. To the extent that we are unable to recover those costs, or if higher rates arising from recovery of such costs result in reduced demand for services, our future financial results may be adversely impacted. Further, as the intensity and frequency of significant weather events increases, insurers may reprice or remove themselves from insuring risks for which the company has historically maintained insurance, resulting in increased cost or risk to us. Our strategy may be impacted by policy and legal, technology, market and reputational risks and opportunities that are associated with the transition to a lower-carbon economy, as disclosed in other risk factors in this section. As a result of increased awareness regarding climate change, coupled with adverse economic conditions, availability of alternative energy sources, including private solar, microturbines, fuel cells, energy-efficient buildings and energy storage devices, and new regulations restricting emissions, including potential regulations of methane emissions, some consumers and companies may use less energy, meet their own energy needs through alternative energy sources or avoid expansions of their facilities, including natural gas facilities, which may result in less demand for our services. As these technologies become a more cost-competitive option over time, whether through cost effectiveness or government incentives and subsidies, certain customers may choose to meet their own energy needs and subsequently decrease usage of our systems and services, which may result in, among other things, our generating facilities becoming less competitive and economical. Further, evolving investor sentiment related to the use of fossil fuels and initiatives to restrict continued production of fossil fuels could result in a significant impact on our electric generation and natural gas businesses in the future. ITEM 1A. RISK FACTORS N I S OURCE I NC . Some of our baseload generation is dependent on natural gas and coal, and we pass through the costs for these energy sources to our customers. In addition, in our gas distribution business, we procure natural gas on behalf of certain customers, and we pass through the actual cost of the gas consumed. Diminished investor interest in funding fossil fuel development could reduce the amount of exploration and production of natural gas or coal, or investment in gas transmission pipelines. Reduced production and transportation of natural gas could, in the long-term, lead to supply shortages leading to baseload generation outages. Given that we pass through commodity costs to customers, this could also create the potential for regulatory questions resulting from increased customer costs. We are unable to forecast the future of commodity markets, but reduced fossil fuel investment, due to evolving investor sentiment, could lead to higher commodity prices and shortages impacting our generation and our reputation with regulators. Conversely, demand for our services may increase as a result of customer changes in response to climate change. For example, as the utilization of electric vehicles increases, demand for electricity may increase, resulting in increased usage of our systems and services. Any negative views with respect to our environmental practices or our ability to meet the challenges posed by climate change from regulators, customers, investors or legislators could harm our reputation and adversely affect the perceived value of our products and services. Changes in policy to combat climate change, and technology advancement, each of which can also accelerate the implications of a transition to a lower carbon economy, may materially adversely impact our business, financial position, results of operations, and cash flows . For example, in February 2023, the Maryland Office of People's Counsel filed a petition with the Maryland Public Service Commission seeking an investigation regarding planning, practices, and future operations of natural gas suppliers in the state. We are subject to operational and financial risks and liabilities associated with the implementation and efforts to achieve our carbon emission reduction goals. On November 7, 2022, we announced our goal of reaching net zero Scope 1 and 2 greenhouse gas emissions by 2040 (the Net Zero Goal). Achieving the Net Zero Goal will require supportive regulatory and legislative policies, favorable stakeholder environments and advancement of technologies that are not currently economical to deploy, the impacts and costs of which are not fully understood at this time. NIPSCOs electric generation transition is a key element of the Net Zero Goal. Our analysis and plan for execution, which is outlined in the NIPSCO 2021 Integrated Resource Plan, requires us to make a number of assumptions. These goals and underlying assumptions involve risks and uncertainties and are not guarantees. Should one or more of our underlying assumptions prove incorrect, our actual results and ability to achieve our emissions goal could differ materially from our expectations. Certain of the assumptions that could impact our ability to meet our emissions goal include, but are not limited to: the accuracy of current emission measurements, service territory size and capacity needs remaining in line with expectations; regulatory approval; impacts of future environmental regulations or legislation; impact of future GHG pricing regulations or legislation, including a future carbon tax or methane fee; price, availability and regulation of carbon offsets; price of fuel, such as natural gas; cost of energy generation technologies, such as wind and solar, natural gas and storage solutions; adoption of alternative energy by the public, including adoption of electric vehicles; rate of technology innovation with regards to alternative energy resources; our ability to implement our modernization plans for our pipelines and facilities; the ability to complete and implement generation alternatives to NIPSCOs coal generation and retirement dates of NIPSCOs coal facilities by 2028; the ability to construct and/or permit new natural gas pipelines; the ability to procure resources needed to build at a reasonable cost, the lack of scarcity of resources and labor, project cancellations, construction delays or overruns and the ability to appropriately estimate costs of new generation; impact of any supply chain disruptions; and advancement of energy efficiencies. Any negative opinions with respect to these goals or our environmental practices, including any inability to achieve, or a scaling back of these goals, formed by regulators, customers, investors or legislators could harm our reputation and have an adverse effect on our financial condition. FINANCIAL, ECONOMIC AND MARKET RISKS We have substantial indebtedness which could adversely affect our financial condition. Our business is capital intensive and we rely significantly on long-term debt to fund a portion of our capital expenditures and repay outstanding debt, and on short-term borrowings to fund a portion of day-to-day business operations. We had total consolidated indebtedness of $11,315.5 million outstanding as of December 31, 2022. Our substantial indebtedness could have important consequences. For example, it could: limit our ability to borrow additional funds or increase the cost of borrowing additional funds; reduce the availability of cash flow from operations to fund working capital, capital expenditures and other general corporate purposes; ITEM 1A. RISK FACTORS N I S OURCE I NC . limit our flexibility in planning for, or reacting to, changes in the business and the industries in which we operate; lead parties with whom we do business to require additional credit support, such as letters of credit, in order for us to transact such business; place us at a competitive disadvantage compared to competitors that are less leveraged; increase vulnerability to general adverse economic and industry conditions; and limit our ability to execute on our growth strategy, which is dependent upon access to capital to fund our substantial infrastructure investment program. Some of our debt obligations contain financial covenants related to debt-to-capital ratios and cross-default provisions. Our failure to comply with any of these covenants could result in an event of default, which, if not cured or waived, could result in the acceleration of outstanding debt obligations. A drop in our credit ratings could adversely impact our cash flows, results of operation, financial condition and liquidity. The availability and cost of credit for our businesses may be greatly affected by credit ratings. The credit rating agencies periodically review our ratings, taking into account factors such as our capital structure, earnings profile, and overall shifts in the economy or business environment. We are committed to maintaining investment grade credit ratings; however, there is no assurance we will be able to do so in the future. Our credit ratings could be lowered or withdrawn entirely by a rating agency if, in its judgment, the circumstances warrant. Any negative rating action could adversely affect our ability to access capital at rates and on terms that are attractive. A negative rating action could also adversely impact our business relationships with suppliers and operating partners, who may be less willing to extend credit or offer us similarly favorable terms as secured in the past under such circumstances. Certain of our subsidiaries have agreements that contain ratings triggers that require increased collateral in the form of cash, a letter of credit or other forms of security for new and existing transactions if our credit ratings (including the standalone credit ratings of certain of our subsidiaries) are dropped below investment grade. These agreements are primarily for insurance purposes and for the physical purchase or sale of gas or power. As of December 31, 2022, the collateral requirement that would be required in the event of a downgrade below the ratings trigger levels would amount to approximately $85.7 million. In addition to agreements with ratings triggers, there are other agreements that contain adequate assurance or material adverse change provisions that could necessitate additional credit support such as letters of credit and cash collateral to transact business. If our or certain of our subsidiaries credit ratings were downgraded, especially below investment grade, financing costs and the principal amount of borrowings would likely increase due to the additional risk of our debt and because certain counterparties may require additional credit support as described above. Such amounts may be material and could adversely affect our cash flows, results of operations and financial condition. Losing investment grade credit ratings may also result in more restrictive covenants and reduced flexibility on repayment terms in debt issuances, lower share price and greater stockholder dilution from common equity issuances, in addition to reputational damage within the investment community. Adverse economic and market conditions, including increased inflation, increases in interest rates, recession or changes in investor sentiment could materially and adversely affect our business, results of operations, cash flows, financial condition and liquidity. Deteriorating, sluggish or volatile economic conditions in our operating jurisdictions could adversely impact our ability to maintain or grow our customer base and collect revenues from customers, which could reduce our revenue or growth rate and increase operating costs. A continued economic downturn or recession, or slowing or stalled recovery from such economic downturn or recession, may have a material adverse effect on our business, financial condition, or results of operations. We rely on access to the capital markets to finance our liquidity and long-term capital requirements, including expenditures for our utility infrastructure and to comply with future regulatory requirements, to the extent not satisfied by the cash flow generated by our operations. We have historically relied on long-term debt and on the issuance of equity securities to fund a portion of our capital expenditures and repay outstanding debt, and on short-term borrowings to fund a portion of day-to-day business operations. Actions to reduce inflation, including raising interest rates, increase our cost of borrowing, which in turn could make it more difficult to obtain financing for our operations or investments on favorable terms. Successful implementation of our long-term business strategies, including capital investment, is dependent upon our ability to access the ITEM 1A. RISK FACTORS N I S OURCE I NC . capital and credit markets, including the banking and commercial paper markets, on competitive terms and rates. An economic downturn or uncertainty, market turmoil, changes in interest rates, changes in tax policy, challenges faced by financial institutions, changes in our credit ratings, or a change in investor sentiment toward us or the utilities industry generally could adversely affect our ability to raise additional capital or refinance debt. For example, because NIPSCOs current generating facilities substantially rely on coal for its operations, certain financial institutions may choose not to participate in our financing arrangements. In addition, large institutional investors may choose to sell or choose not to purchase our stock due to environmental, social and governance (ESG) concerns or concerns regarding renewable energy supply chain challenges. Reduced access to capital markets, increased borrowing costs, and/or lower equity valuation levels could reduce future earnings per share and cash flows. In addition, any rise in interest rates may lead to higher borrowing costs, which may adversely impact reported earnings, cost of capital and capital holdings. If, in the future, we face limits to the credit and capital markets or experience significant increases in the cost of capital or are unable to access the capital markets, it could limit our ability to implement, or increase the costs of implementing, our business plan, which, in turn, could materially and adversely affect our results of operations, cash flows, financial condition and liquidity. The COVID-19 pandemic has adversely impacted and may continue to adversely impact our business, results of operations, financial condition, liquidity and cash flows. The COVID-19 pandemic has resulted in widespread impacts on the global economy and financial markets. The duration and ultimate impact of the COVID-19 pandemic on our business, results of operations and financial condition, including liquidity, capital and financing resources, will depend on numerous evolving factors and future developments, which are highly uncertain and cannot be predicted at this time. Such factors and developments may include the severity and duration of the COVID-19 pandemic, including whether there are periods of increased COVID-19 cases; the emergence of other new or more contagious variants that may render vaccines ineffective or less effective; disruption to our operations resulting from employee illnesses or any inability to attract, retain or motivate employees; the development, availability and administration of effective treatment or vaccines and the willingness of individuals to receive a vaccine; the extent and duration of the impact on the U.S. or global economy, including the pace and extent of recovery from the COVID-19 pandemic; and the actions that have been or may be taken by various governmental authorities in response to the COVID-19 pandemic. Most of our revenues are subject to economic regulation and are exposed to the impact of regulatory rate reviews and proceedings. Most of our revenues are subject to economic regulation at either the federal or state level. As such, the revenues generated by us are subject to regulatory review by the applicable federal or state authority. These rate reviews determine the rates charged to customers and directly impact revenues. Our financial results are dependent on frequent regulatory proceedings in order to ensure timely recovery of costs and investments. As described in more detail in the risk factor below, the outcomes of these proceedings are uncertain, potentially lengthy and could be influenced by many factors, some of which may be outside of our control, including the cost of providing service, the necessity of expenditures, the quality of service, regulatory interpretations, customer intervention, economic conditions and the political environment. Further, the rate orders are subject to appeal, which creates additional uncertainty as to the rates that will ultimately be allowed to be charged for services. The actions of regulators and legislators could result in outcomes that may adversely affect our earnings and liquidity. The rates that our electric and natural gas companies charge their customers are determined by their state regulatory commissions and by the FERC. These commissions also regulate the companies accounting, operations, the issuance of certain securities and certain other matters. The FERC also regulates the transmission of electric energy, the sale of electric energy at wholesale, accounting, issuance of certain securities and certain other matters, including reliability standards through the North American Electric Reliability Corporation (NERC). Under state and federal law, our electric and natural gas companies are entitled to charge rates that are sufficient to allow them an opportunity to recover their prudently incurred operating and capital costs and a reasonable rate of return on invested capital, to attract needed capital and maintain their financial integrity, while also protecting relevant public interests. Our electric and natural gas companies are required to engage in regulatory approval proceedings as a part of the process of establishing the terms and rates for their respective services. Each of these companies prepares and submits periodic rate filings with their respective regulatory commissions for review and approval, which allows for various entities to challenge our current or future rates, structures or mechanisms and could alter or limit the rates we are allowed to charge our customers. These proceedings typically involve multiple parties, including governmental bodies and officials, consumer advocacy groups, and various consumers of energy, who have differing concerns. Any change in rates, including changes in allowed rate of return, are subject ITEM 1A. RISK FACTORS N I S OURCE I NC . to regulatory approval proceedings that can be contentious, lengthy, and subject to appeal. This may lead to uncertainty as to the ultimate result of those proceedings. Established rates are also subject to subsequent prudency reviews by state regulators, whereby various portions of rates could be adjusted, subject to refund or disallowed, including cost recovery mechanisms. The ultimate outcome and timing of regulatory rate proceedings could have a significant effect on our ability to recover costs or earn an adequate return. Adverse decisions in our proceedings could adversely affect our financial position, results of operations and cash flows. There can be no assurance that regulators will approve the recovery of all costs incurred by our electric and natural gas companies, including costs for construction, operation and maintenance, and compliance with current and future changes in environmental, federal pipeline safety, critical infrastructure and cyber security laws and regulations. Challenges arise with state regulators on inflationary pricing for electric and gas materials and potential price increases, ensuring that updated pricing for electric and gas materials is included in plans and regulatory assumptions, and ensuring there is a regulatory recovery model for emergency inventory stock. There is debate among state regulators and other stakeholders over how to transition to a decarbonized economy and prudency arguments relative to investing in natural gas assets when the depreciable life of the assets may be shortened due to electrification. The inability to recover a significant amount of operating costs could have an adverse effect on a companys financial position, results of operations and cash flows. Changes to rates may occur at times different from when costs are incurred. Additionally, catastrophic events at other utilities could result in our regulators and legislators imposing additional requirements that may lead to additional costs for the companies. In addition to the risk of disallowance of incurred costs, regulators may also impose downward adjustments in a companys allowed ROE as well as assess penalties and fines. Regulators may reduce ROE to mitigate potential customer bill increases due to items unrelated to capital investments such as potential increases in taxes and incremental costs related to COVID-19. These actions would have an adverse effect on our financial position, results of operations and cash flows. Our electric business is subject to mandatory reliability and critical infrastructure protection standards established by NERC and enforced by the FERC. The critical infrastructure protection standards focus on controlling access to critical physical and cybersecurity assets. Compliance with the mandatory reliability standards could subject our electric utilities to higher operating costs. In addition, compliance with PHMSA regulations could subject our gas utilities to higher operating costs. If our businesses are found to be in noncompliance, we could be subject to sanctions, including substantial monetary penalties, or damage to our reputation. Changes in tax laws, as well as the potential tax effects of business decisions, could negatively impact our business, results of operations (including our expected project returns from our planned renewable energy projects), financial condition and cash flows. Our business operations are subject to economic conditions in certain industries. Business operations throughout our service territories have been and may continue to be adversely affected by economic events at the national and local level where our businesses operate. In particular, sales to large industrial customers, such as those in the steel, oil refining, industrial gas and related industries, are impacted by economic downturns and recession; geographic or technological shifts in production or production methods; and consumer demand for environmentally friendly products and practices. The U.S. manufacturing industry continues to adjust to changing market conditions including international competition, inflation and increasing costs, and fluctuating demand for its products. In addition, our results of operations are negatively impacted by lower revenues resulting from higher bankruptcies, predominately focused on commercial and industrial customers not able to sustain operations through the economic disruptions related to the pandemic. We are exposed to risk that customers will not remit payment for delivered energy or services, and that suppliers or counterparties will not perform under various financial or operating agreements. Our extension of credit is governed by a Corporate Credit Risk Policy, involves considerable judgment by our employees and is based on an evaluation of a customer or counterpartys financial condition, credit history and other factors. We monitor our credit risk exposure by obtaining credit reports and updated financial information for customers and suppliers, and by evaluating the financial status of our banking partners and other counterparties by reference to market-based metrics such as credit default swap pricing levels, and to traditional credit ratings provided by the major credit rating agencies. Adverse economic conditions result in an increase in defaults by customers, suppliers and counterparties. ITEM 1A. RISK FACTORS N I S OURCE I NC . We are a holding company and are dependent on cash generated by our subsidiaries to meet our debt obligations and pay dividends on our stock. We are a holding company and conduct our operations primarily through our subsidiaries, which are separate and distinct legal entities. Substantially all of our consolidated assets are held by our subsidiaries. Accordingly, our ability to meet our debt obligations or pay dividends on our common stock and preferred stock is largely dependent upon cash generated by these subsidiaries. In the event a major subsidiary is not able to pay dividends or transfer cash flows to us, our ability to service our debt obligations or pay dividends could be negatively affected. The trading prices for our Equity Units, initially consisting of Corporate Units, and related treasury units and Series C Mandatory Convertible Preferred Stock, are expected to be affected by, among other things, the trading prices of our common stock, the general level of interest rates and our credit quality. The trading prices of the Equity Units, initially consisting of Corporate Units, which are listed on the New York Stock Exchange, and the related treasury units and Series C Mandatory Convertible Preferred Stock in the secondary market, are expected to be affected by, among other things, the trading prices of our common stock, the general level of interest rates and our credit quality. It is impossible to predict whether the price of our common stock or interest rates will rise or fall. The price of our common stock could be subject to wide fluctuations in the future in response to many events or factors, including those discussed in the risk factors herein, many of which events and factors are beyond our control. Fluctuations in interest rates may give rise to arbitrage opportunities based upon changes in the relative value of the common stock underlying the purchase contracts and of the other components of the Equity Units. Any such arbitrage could, in turn, affect the trading prices of the Corporate Units, treasury units, mandatory convertible preferred stock and our common stock. The early settlement right triggered under certain circumstances and the supermajority rights of the Series C Mandatory Convertible Preferred Stock following a fundamental change, could discourage a potential acquirer. The fundamental change early settlement right with respect to the purchase contracts triggered under certain circumstances by a fundamental change and the supermajority voting rights of the Series C Mandatory Convertible Preferred Stock in connection with certain fundamental change transactions jointly could discourage a potential acquirer, including potential acquirers that would otherwise seek a transaction with us that would be attractive to our investors. Our Equity Units, initially consisting of Corporate Units, and related Series C Mandatory Convertible Preferred Stock, and the issuance and sale of common stock in settlement of the purchase contracts and conversion of mandatory convertible preferred stock, may all adversely affect the market price of our common stock and will cause dilution to our stockholders. The market price of our common stock is likely to be influenced by our Equity Units, initially consisting of Corporate Units, and related mandatory convertible preferred stock. For example, the market price of our common stock could become more volatile and could be depressed by: investors anticipation of the sale into the market of a substantial number of additional shares of our common stock issued upon settlement of the purchase contracts or conversion of our mandatory convertible preferred stock; possible sales of our common stock by investors who view our Equity Units, initially consisting of Corporate Units, or related mandatory convertible preferred stock as a more attractive means of equity participation in us than owning shares of our common stock; and hedging or arbitrage trading activity that may develop involving our Equity Units, initially consisting of Corporate Units, or related mandatory convertible preferred stock and our common stock. In addition, we cannot predict the effect that future issuances or sales of our common stock, if any, including those made upon the settlement of the purchase contracts or conversion of the mandatory convertible preferred stock, may have on the market price for our common stock. Our Equity Units, initially consisting of Corporate Units, and the issuance and sale of substantial amounts of common stock, including issuances and sales upon the settlement of the purchase contracts or conversion of the mandatory convertible preferred stock, could adversely affect the market price of our common stock and will cause dilution to our stockholders. Capital market performance and other factors may decrease the value of benefit plan assets, which then could require significant additional funding and impact earnings. ITEM 1A. RISK FACTORS N I S OURCE I NC . The performance of the capital markets affects the value of the assets that are held in trust to satisfy future obligations under defined benefit pension and other postretirement benefit plans. We have significant obligations in these areas and hold significant assets in these trusts. These assets are subject to market fluctuations and may yield uncertain returns, which fall below our projected rates of return. A decline in the market value of assets may increase the funding requirements of the obligations under the defined benefit pension plans. Additionally, changes in interest rates affect the liabilities under these benefit plans; as interest rates decrease, the liabilities increase, which could potentially increase funding requirements. Further, the funding requirements of the obligations related to these benefits plans may increase due to changes in governmental regulations and participant demographics, including increased numbers of retirements or longer life expectancy assumptions, as well as voluntary early retirements. In addition, lower asset returns result in increased expenses. Ultimately, significant funding requirements and increased pension or other postretirement benefit plan expense could negatively impact our results of operations and financial position. We have significant goodwill. Any future impairments of goodwill could result in a significant charge to earnings in a future period and negatively impact our compliance with certain covenants under financing agreements. In accordance with GAAP, we test goodwill for impairment at least annually and review our definite-lived intangible assets for impairment when events or changes in circumstances indicate its fair value might be below its carrying value. Goodwill is also tested for impairment when factors, examples of which include reduced cash flow estimates, a sustained decline in stock price or market capitalization below book value, indicate that the carrying value may not be recoverable. A significant charge in the future could impact the capitalization ratio covenant under certain financing agreements. We are subject to a financial covenant under our revolving credit facility and term credit agreement, which requires us to maintain a debt to capitalization ratio that does not exceed 70%. As of December 31, 2022, the ratio was 58.9 %. LITIGATION, REGULATORY AND LEGISLATIVE RISKS The outcome of legal and regulatory proceedings, investigations, inquiries, claims and litigation related to our business operations may have a material adverse effect on our results of operations, financial position or liquidity. We are involved in legal and regulatory proceedings, investigations, inquiries, claims and litigation in connection with our business operations, including those related to the Greater Lawrence Incident, the most significant of which are summarized in Note 19, "Other Commitments and Contingencies," in the Notes to Consolidated Financial Statements. Our insurance does not cover all costs and expenses that we have incurred relating to the Greater Lawrence Incident, and does not fully cover incidents that could occur in the future. Due to the inherent uncertainty of the outcomes of such matters, there can be no assurance that the resolution of any particular claim or proceeding would not have a material adverse effect on our results of operations, financial position or liquidity. The Greater Lawrence Incident has materially adversely affected and may continue to materially adversely affect our financial condition, results of operations and cash flows and we may have continued financial liabilities related to the sale of the Massachusetts Business. In connection with the Greater Lawrence Incident, we have incurred and will incur various costs and expenses. While we have recovered the full amount of our liability insurance coverage available under our policies, total expenses related to the incident exceeded such amount. Expenses in excess of our liability insurance coverage have materially adversely affected and may continue to materially adversely affect our results of operations, cash flows and financial position. We may also incur additional costs associated with the Greater Lawrence Incident, beyond the amount currently anticipated, including in connection with civil litigation. Additionally, it may be difficult to determine whether a claim for damages from a third party related to the Massachusetts Business or the Greater Lawrence Incident is our responsibility or Eversources, and we may expend substantial resources trying to determine whether we or Eversource has responsibility for the claim. Further, state or federal legislation may be enacted that would require us to incur additional costs by mandating various changes, including changes to our operating practice standards for natural gas distribution operations and safety. In addition, if it is determined in other matters that we did not comply with applicable statutes, regulations or rules in connection with the operations or maintenance of our natural gas system, and we are ordered to pay additional amounts in penalties, or other amounts, our financial condition, results of operations, and cash flows could be materially and adversely affected. Our settlement with the U.S. Attorneys Office in respect of federal charges in connection with the Greater Lawrence Incident may expose us to further penalties, liabilities and private litigation, and may impact our operations. On February 26, 2020, the Company entered into a DPA and Columbia of Massachusetts entered into a plea agreement with the U.S. Attorneys Office to resolve the U.S. Attorneys Offices investigation relating to the Greater Lawrence Incident, which ITEM 1A. RISK FACTORS N I S OURCE I NC . was subsequently approved by the United States District Court for the District of Massachusetts. The agreements impose various compliance and remedial obligations on the Company and Columbia of Massachusetts. Failure to comply with the terms of these agreements could result in further enforcement action by the U.S. Attorneys Office, expose the Company and Columbia of Massachusetts to penalties, financial or otherwise, and subject the

Company to further private litigation, each of which could impact our operations and have a material adverse effect on our business. Our businesses are subject to various federal, state and local laws, regulations, tariffs and policies. We could be materially adversely affected if we fail to comply with such laws, regulations, tariffs and policies or with any changes in or new interpretations of such laws, regulations, tariffs and policies. Our businesses are subject to various federal, state and local laws, regulations, tariffs and policies, including, but not limited to, those relating to natural gas pipeline safety, employee safety, the environment and our energy infrastructure. In particular, we are subject to significant federal, state and local regulations applicable to utility companies, including regulations by the various utility commissions in the states where we serve customers. These regulations significantly influence our operating environment, may affect our ability to recover costs from utility customers, and cause us to incur substantial compliance and other costs. Existing laws, regulations, tariffs and policies may be revised or become subject to new interpretations, and new laws, regulations, tariffs and policies may be adopted or become applicable to us and our operations. In some cases, compliance with new laws, regulations, tariffs and policies increases our costs or risks of liability. Supply chain constraints may challenge our ability to remain in compliance if we cannot obtain the materials that we need to operate our business in a compliant manner. If we fail to comply with laws, regulations and tariffs applicable to us or with any changes in or new interpretations of such laws, regulations, tariffs or policies, our financial condition, results of operations, regulatory outcomes and cash flows may be materially adversely affected. Our businesses are regulated under numerous environmental laws and regulations. The cost of compliance with these laws and regulations, and changes to or additions to, or reinterpretations of the laws and regulations, could be significant, and the cost of compliance may not be recoverable. Liability from the failure to comply with existing or changed laws and regulations could have a material adverse effect on our business, results of operations, cash flows and financial condition. Our businesses are subject to extensive federal, state and local environmental laws and rules that regulate, among other things, air emissions, water usage and discharges, GHG and waste products such as CCR. Compliance with these legal obligations require us to make significant expenditures for installation of pollution control equipment, remediation, environmental monitoring, emissions fees, and permits at many of our facilities. Furthermore, if we fail to comply with environmental laws and regulations or are found to have caused damage to the environment or persons, that failure or harm may result in the assessment of civil or criminal penalties and damages against us, injunctions to remedy the failure or harm, and the inability to operate facilities as designed and intended. Existing environmental laws and regulations may be revised and new laws and regulations may be adopted or become applicable to us, with an increasing focus on the impact of coal and natural gas facilities that may result in significant additional expense and operating restrictions on our facilities, which may not be fully recoverable from customers and could materially affect the continued economic viability of our facilities. An area of significant uncertainty and risk are potential changes to the laws concerning emission of GHG. While we continue to execute our plan to reduce our Scope 1 GHG emissions through the retirement of coal-fired electric generation, increased sourcing of renewable energy, priority pipeline replacement, leak detection and repair, and other methods, and while we have set a Net Zero Goal, GHG emissions are anticipated to be associated with energy delivery for many years. Future GHG legislation and/or regulation related to the generation of electricity or the extraction, production, distribution, transmission, storage and end use of natural gas could materially impact our gas supply, financial position, financial results and cash flows. Another area of significant uncertainty and risk are the regulations concerning CCR. The EPA has issued regulations and plans to promulgate additional regulations concerning the management, transformation, transportation and storage of CCRs. NIPSCO is also incurring or will incur costs associated with closing, corrective action, and ongoing monitoring of certain CCR impoundments. We have two pending petitions at the Indiana Utility Regulatory Commission (IURC) seeking recovery of ash pond closure costs related to federal regulations governing CCRs at the Michigan City and R.M. Schahfer Generating Stations and believe there is supportive Indiana law authorizing such recovery. Further, a release of CCR to the environment could result in remediation costs, penalties, claims, litigation, increased compliance costs, and reputational damage. We currently have a pending application with the EPA to continue operation of a CCR impoundment that is tied to operation of R.M. Schahfer Generating Station Units 17 and 18 to the end of 2025, with the CCR impoundment closing by October 2028. In ITEM 1A. RISK FACTORS N I S OURCE I NC . proposed and final EPA actions denying continued operation of CCR impoundments at other utilities, EPA said that CCR impoundments should cease receipt of CCRs within 135 days of final EPA action unless certain conditions are demonstrated, such as potential reliability issues. In the event that approval is not obtained, future operations could be impacted. The actual future expenditures to achieve environmental compliance depends on many factors, including the nature and extent of impact, the method of improvement, the cost of raw materials, contractor costs, and requirements established by environmental authorities. Changes in costs and the ability to recover under regulatory mechanisms could affect our financial position, financial results and cash flows. Changes in taxation and the ability to quantify such changes as well as challenges to tax positions could adversely affect our financial results. We are subject to taxation by the various taxing authorities at the federal, state and local levels where we do business. Legislation or regulation which could affect our tax burden could be enacted by any of these governmental authorities. The IRA imposed a 15 percent minimum tax rate on book earnings for corporations with higher than $1 billion of annual income, along with a 1 percent excise tax on corporate stock repurchases while providing tax incentives to promote various clean energy initiatives. We are currently assessing the potential impact of these legislative changes. The outcome of regulatory proceedings regarding the extent to which the effect of a change in corporate tax rate will impact customers and the time period over which the impact will occur could significantly impact future earnings and cash flows. Separately, a challenge by a taxing authority, changes in taxing authorities administrative interpretations, decisions, policies and positions, our ability to utilize tax benefits such as carryforwards or tax credits, or a deviation from other tax-related assumptions may cause actual financial results to deviate from previous estimates. s

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ITEM 1. BUSINESS OVERVIEW ##TABLE_START ##TABLE_ENDNW Holdings is a holding company headquartered in Portland, Oregon and owns NW Natural, NW Natural Water Company, LLC (NWN Water), NW Natural Renewables Holdings, LLC, a non-regulated subsidiary established to pursue non-regulated renewable natural gas activities, and other businesses and activities. NW Natural is NW Holdings largest subsidiary. NW Natural distributes natural gas to residential, commercial, and industrial customers in Oregon and southwest Washington. NW Natural and its predecessors have supplied gas service to the public since 1859, was incorporated in Oregon in 1910, and began doing business as NW Natural in 1997. NW Natural's natural gas distribution activities are reported in the natural gas distribution (NGD) segment. All other business activities, including certain gas storage activities, water and wastewater businesses, non-regulated renewable natural gas activities and other investments and activities are aggregated and reported as "other" at their respective registrant. NATURAL GAS DISTRIBUTION (NGD) SEGMENT ##TABLE_START ##TABLE_ENDBoth NW Holdings and NW Natural have one reportable segment, the NGD segment, which is operated by NW Natural. NGD provides natural gas service through approximately 795,000 meters in Oregon and southwest Washington. Approximately 88% of customers are located in Oregon and 12% are located in southwest Washington. NW Natural has been allocated an exclusive service territory by the Oregon Public Utility Commission (OPUC) and Washington Utilities and Transportation Commission (WUTC), which includes the major population centers in western Oregon, including the Portland metropolitan area, most of the Willamette Valley, the Coastal area from Astoria to Coos Bay, and portions of Washington along the Columbia River. Major businesses located in NW Natural's service territory include retail, manufacturing, and high-technology industries. Customers The NGD business serves residential, commercial, and industrial customers with no individual customer accounting for more than 10% of NW Natural's or NW Holdings' revenues. On an annual basis, residential and commercial customers typically account for approximately 60% of NGD volumes delivered and approximately 90% of NGD margin. Industrial and other customers largely account for the remaining volumes and margin. The following table presents summary meter information for the NGD segment as of December 31, 2022: ##TABLE_START Number of Meters % of Volumes % of Margin Residential 724,287 38 % 65 % Commercial 69,139 23 % 25 % Industrial 1,071 39 % 7 % Other (1) N/A N/A 3 % Total 794,497 100 % 100 % ##TABLE_END(1) NGD margin is also affected by other items, including miscellaneous revenues, gains or losses from NW Natural's gas cost incentive sharing mechanism, other margin adjustments, and other regulated services. Generally, residential and commercial customers purchase both their natural gas commodity (gas sales) and natural gas delivery services (transportation services) from the NGD business. Industrial customers also purchase transportation services, but may buy the gas commodity either from NW Natural or directly from a third-party gas marketer or supplier. Gas commodity cost is primarily a pass-through cost to customers; therefore, profit margins are not significantly affected by an industrial customer's decision to purchase gas from NW Natural or from third parties. Industrial and large commercial customers may also select between firm and interruptible service levels, with firm services generally providing higher profit margins compared to interruptible services. To help manage gas supplies, industrial tariffs are designed to provide some certainty regarding industrial customers' volumes by requiring an annual service election, special rates or possible restrictions for changes between elections, and in some cases, a minimum or maximum volume requirement before changing options. We estimate natural gas was in approximately 63% of single-family residential homes in NW Natural's service territory in 2022. Customer growth in our region comes mainly from the following sources: single-family housing, both new construction and conversions; multifamily housing new construction; and commercial buildings, both new construction and conversions. Single-family new construction has consistently been our largest source of growth. Continued customer growth is closely tied to consumer preference for natural gas, the comparative price of natural gas to electricity and fuel oil, regulations and building codes permitting the use of natural gas in new construction and conversions, and the economic health of our service territory. Competitive Conditions In its service areas, the NGD business has no direct competition from other natural gas distributors. However, it competes with other forms of energy in each customer class. This competition among energy suppliers is based on price, efficiency, reliability, performance, preference, market conditions, building codes, technology, federal, state, and local energy policy, and environmental impacts. For residential and small to mid-size commercial customers, the NGD business competes primarily with providers of electricity, fuel oil, and propane. In the industrial and large commercial markets, the NGD business competes with all forms of energy, including competition from wholesale natural gas marketers. In addition, large industrial customers could bypass NW Natural's natural gas distribution system by installing their own direct pipeline connection to the interstate pipeline system. NW Natural has designed custom transportation service agreements with several large industrial customers to provide transportation service rates that are competitive with the customers costs of installing their own pipeline. Seasonality of Business The NGD business is seasonal in nature due to higher gas usage by residential and commercial customers during the cold winter heating months. Other categories of customers experience similar seasonality in their usage but to a lesser extent. Regulation and Rates The NGD business is subject to regulation by the OPUC and WUTC. These regulatory agencies authorize rates and allow recovery mechanisms to provide the opportunity to recover prudently incurred capital and operating costs from customers, while also earning a reasonable return on investment for investors. In addition, the OPUC and WUTC also regulate the system of accounts and issuance of securities by NW Natural. NW Natural files general rate cases and rate tariff requests periodically with the OPUC and WUTC to establish approved rates, an authorized return on equity (ROE), an overall rate of return (ROR) on rate base, an authorized capital structure, and other revenue/cost deferral and recovery mechanisms. NW Natural is also regulated by the Federal Energy Regulatory Commission (FERC). Under NW Natural's Mist interstate storage certificate with FERC, NW Natural is required to file either a petition for rate approval or a cost and revenue study every five years to change or justify maintaining the existing rates for the interstate storage service. For further discussion on our most recent general rate cases, see Part II, Item 7, "Results of OperationsRegulatory Matters Regulation and Rates ." Gas Supply NW Natural strives to secure sufficient, reliable supplies of natural gas to meet the needs of customers at the lowest reasonable cost, while maintaining price stability, managing gas purchase costs prudently and supporting our core value of environmental stewardship. This is accomplished through a comprehensive strategy focused on the following items: Reliability - ensuring gas resource portfolios are sufficient to satisfy customer requirements under extreme cold weather conditions; Diverse Supply - providing diversity of supply sources; Diverse Contracts - maintaining a variety of contract durations, types, and counterparties; Cost Management and Recovery - employing prudent gas cost management strategies; and Environmental Stewardship - striving to reduce the carbon content and environmental impacts of the energy we deliver. Reliability To support system reliability, the NGD business has developed a risk-based methodology in which it uses a planning standard to serve the highest firm sales demand day in any year with 99% certainty. The projected maximum design day firm NGD customer sales is approximately 10 million therms. Of this total, the NGD business is currently capable of meeting approximately 50% of the requirements with gas from storage located within or adjacent to its service territory, while the remaining supply requirements would come from gas purchases under firm gas purchase contracts and recall agreements. NW Natural segments transportation capacity, which is a natural gas transportation mechanism under which a shipper can leverage its firm pipeline transportation capacity by separating it into multiple segments with alternate delivery routes. The reliability of service on these alternate routes will vary depending on the constraints of the pipeline system. For those segments with acceptable reliability, segmentation provides a shipper with increased flexibility and potential cost savings compared to traditional pipeline service. The NGD business relies on segmentation of firm pipeline transportation capacity that flows from Stanfield, Oregon to various points south of Molalla, Oregon. We believe gas supplies would be sufficient to meet existing NGD firm customer demand in the event of maximum design day weather conditions. The following table shows the sources of supply projected to be used to satisfy the design day sales for the 2022-23 winter heating season: ##TABLE_START Therms in millions Therms Percent Sources of NGD supply: Firm supply purchases 3.4 34 % Mist underground storage (NGD only) 3.1 30 % Company-owned LNG storage 1.9 19 % Off-system storage contract 0.5 5 % Pipeline segmentation capacity 0.6 6 % Recall agreements 0.4 4 % Peak day citygate deliveries 0.2 2 % Total 10.1 100 % ##TABLE_ENDThe OPUC and WUTC have Integrated Resource Planning (IRP) processes in which utilities define different future scenarios and corresponding resource and compliance strategies in an effort to evaluate supply and demand resource and compliance requirements, consider uncertainties in the planning process and the need for flexibility to respond to changes, and establish a plan for providing reliable service while meeting carbon compliance obligations within frameworks that emphasize least cost and risk. NW Natural generally files a full IRP biennially for Oregon and Washington with the OPUC and the WUTC, respectively, and files updates in Oregon between filings. The OPUC acknowledges NW Natural's action plan, whereas the WUTC provides notice that the IRP has met the requirements of the Washington Administrative Code. OPUC acknowledgment of the IRP does not constitute ratemaking approval of any specific resource acquisition strategy or expenditure. For additional information see Part II, Item 7, "Results of Operations Regulatory Matters ." Diversity of Supply Sources NW Natural purchases gas supplies primarily from the Alberta and British Columbia provinces of Canada and multiple receipt points in the U.S. Rocky Mountains to protect against regional supply disruptions and to take advantage of price differentials. For 2022, 60% of gas supply came from Canada, with the balance primarily coming from the U.S. Rocky Mountain region. The extraction of shale gas has increased the availability of gas supplies throughout North America. We believe gas supplies available in the western United States and Canada are adequate to serve NGD customer requirements for the foreseeable future. NW

Natural continues to evaluate the long-term supply mix based on projections of gas production and pricing in the U.S. Rocky Mountain region as well as other regions in North America. NW Natural supplements firm gas supply purchases with gas withdrawals from gas storage facilities, including underground reservoirs and LNG storage facilities. Storage facilities are generally injected with natural gas during the off-peak months in the spring and summer, and the gas is withdrawn for use during peak demand months in the winter. The following table presents the storage facilities available for NGD business supply: ##TABLE_START Maximum Daily Deliverability (therms in millions) Designed Storage Capacity (Bcf) Gas Storage Facilities Owned Facility Mist, Oregon (Mist Facility) (1) 3.1 11.7 Mist, Oregon (North Mist Facility) (2) 1.3 4.1 Contracted Facility Jackson Prairie, Washington (3) 0.5 1.1 LNG Facilities Owned Facilities Newport, Oregon 0.6 1.0 Portland, Oregon 1.3 0.6 Total 6.8 18.5 ##TABLE_END(1) The Mist gas storage facility has a total maximum daily deliverability of 5.1 million therms and a total designed storage capacity of about 17.5 Bcf, of which 3.1 million therms of daily deliverability and 11.7 Bcf of storage capacity are reserved for NGD business customers. (2) The North Mist facility is contracted to exclusively serve Portland General Electric, a local electric utility, and may not be used to serve other NGD customers. See " North Mist Gas Storage Facility " below for more information. (3) The storage facility is located near Chehalis, Washington and is contracted from Northwest Pipeline, a subsidiary of The Williams Companies. The Mist facility serves NGD segment customers and is also used for non-NGD purposes, primarily for contracts with gas storage customers, including utilities and third-party marketers. Under regulatory agreements with the OPUC and WUTC, gas storage at Mist can be developed in advance of NGD customer needs but is subject to recall when needed to serve such customers as their demand increases. When storage capacity is recalled for NGD purposes it becomes part of the NGD segment. In 2022, the NGD business did not recall additional deliverability or associated storage capacity to serve customer needs. The North Mist facility is contracted for the exclusive use of Portland General Electric, a local electric utility, and may not be used to serve other NGD customers. See " North Mist Gas Storage Facility " below. Diverse Contract Durations and Types NW Natural has a diverse portfolio of short-, medium-, and long-term firm gas supply contracts and a variety of contract types including firm and interruptible supplies as well as supplemental supplies from gas storage facilities. The portfolio of firm gas supply contracts typically includes the following gas purchase contracts: year-round and winter-only baseload supplies; seasonal supply with an option to call on additional daily supplies during the winter heating season; and daily or monthly spot purchases. During 2022, a total of 886 million therms were purchased under contracts with durations as follows: ##TABLE_START Contract Duration (primary term) Percent of Purchases Long-term (one year or longer) 29 % Short-term (more than one month, less than one year) 34 Spot (one month or less) 37 Total 100 % ##TABLE_ENDGas supply contracts are renewed or replaced as they expire. During 2022, there was one supplier that provided 10% of the NGD business gas supply requirements. No other individual supplier provided 10% or more of the NGD business gas supply requirements. Gas Cost Management The cost of gas sold to NGD customers primarily consists of the following items, which are included in annual Purchased Gas Adjustment (PGA) rates: gas purchases from suppliers; charges from pipeline companies to transport gas to our distribution system; gas storage costs; gas reserves contracts; gas commodity derivative contracts; and renewable natural gas and its attributes, including renewable thermal certificates (RTCs). We expect that costs to comply with Oregon's Climate Protection Program (CPP) and Washington's Climate Commitment Act (CCA) programs will be included in the cost of gas. The NGD business employs a number of strategies to mitigate the cost of gas sold to customers. The primary strategies for managing gas commodity price risk include: negotiating fixed prices directly with gas suppliers; negotiating financial derivative contracts that: (1) effectively convert floating index prices in physical gas supply contracts to fixed prices (referred to as commodity price swaps); or (2) effectively set a ceiling or floor price, or both, on floating index priced physical supply contracts (referred to as commodity price options such as calls, puts, and collars); buying physical gas supplies at a set price and injecting the gas into storage for price stability and to minimize pipeline capacity demand costs; and investing in gas reserves for longer term price stability. See Note 13 for additional information about our gas reserves. NW Natural also contracts with an independent energy marketing company to capture opportunities regarding storage and pipeline capacity when those assets are not serving the needs of NGD business customers. Asset management activities provide opportunities for cost of gas savings for customers and incremental revenues for NW Natural through regulatory incentive-sharing mechanisms. These activities, net of the amount shared, are included in other for segment reporting purposes. Gas Cost Recovery Mechanisms for gas cost recovery are designed to be fair and reasonable, with an appropriate balance between the interests of customers and NW Natural. In general, natural gas distribution rates are designed to recover the costs of, but not to earn a return on, the gas commodity sold. Risks associated with gas cost recovery are minimized by resetting customer rates annually through the PGA and aligning customer and shareholder interests through the use of sharing, weather normalization, and conservation mechanisms in Oregon. See Part II, Item 7, "Results of Operations Regulatory Matters " and "Results of OperationsBusiness SegmentsNatural Gas Distribution Operations Cost of Gas " . Environmental Stewardship Part of our gas supply strategy is working to reduce the carbon content and the environmental impacts of the energy we deliver. To that end, NW Natural developed and implemented an emissions screening tool that uses Environmental Protection Agency (EPA) data to calculate the relative emissions intensity of gas producer operations and prioritize purchases from lower emitting producers. In 2019, we began using this emissions intensity screening tool alongside other purchasing criteria such as price, credit worthiness and geographic diversity. The result has been a cost-neutral way to reduce carbon emissions associated with our natural gas supply. NW Natural is focused on taking steps to lower its emissions on behalf of customers by purchasing environmental attributes that are generated by the production of renewable natural gas (RNG). Under Oregon Senate Bill 98, NW Natural can purchase or invest in RNG facilities, which generate these environmental attributes known as Renewable Thermal Certificates (RTCs). The RTCs work like renewable energy certificates, or RECs, used in electricity markets. RTCs are verified and certified by the Midwest Renewable Energy Tracking System (M-RETS). The M-RETS Renewable Thermal Tracking System issues one RTC for every dekatherm of RNG injected into the gas system. NW Natural enters into contracts for the purchase of RNG and RTCs either through periodic request for proposals or through formal offerings or informal requests. See Part II, Item 7, "Results of Operations Regulatory Matters ". In addition to purchases of RNG, NW Natural is subject to the carbon-reduction requirements of the Oregon CPP and the Washington CCA programs. NW Natural has modeled pathways to compliance with the CPP and CCA in its most recent IRP, which are currently under review by the OPUC and WUTC. While costs associated with each possible compliance pathway differ, we intend to pursue recovery of the costs associated with these programs in rates. Transportation of Gas Supplies NW Natural's gas distribution system is reliant on a single, bi-directional interstate transmission pipeline to bring gas supplies into the natural gas distribution system. Although dependent on a single pipeline, the pipeline s gas flows into the Portland metropolitan market from two directions: (1) the north, which brings supplies from the British Columbia and Alberta supply basins; and (2) the east, which brings supplies from Alberta as well as the U.S. Rocky Mountain supply basins. NW Natural incurs monthly demand charges related to firm pipeline transportation contracts. These contracts have expiration dates ranging from 2023 to 2061. The largest pipeline agreements are with Northwest Pipeline. NW Natural actively works with Northwest Pipeline and others to renew contracts in advance of expiration to ensure gas transportation capacity is sufficient to meet customer needs. Rates for interstate pipeline transportation services are established by FERC within the U.S. and by Canadian authorities for services on Canadian pipelines. Gas Distribution Safety and the protection of employees, customers, and our communities are, and will remain, top priorities. NW Natural constructs, operates, and maintains its pipeline distribution system and storage operations with the goal of ensuring natural gas is delivered and stored safely, reliably, and efficiently. NW Natural has one of the most modern distribution systems in the country with no identified cast iron pipe or bare steel main. Since the 1980s, NW Natural has taken a proactive approach to replacement programs and partnered with the OPUC and WUTC on progressive regulation to further safety and reliability efforts for the distribution system. In the past, NW Natural had a cost recovery program in Oregon that encompassed programs for cast iron replacement, bare steel replacement, transmission integrity management, and distribution integrity management programs as appropriate. Natural gas distribution businesses are likely to be subject to greater federal and state regulation in the future. Additional operating and safety regulations from the U.S. Department of Transportations Pipeline and Hazardous Materials Safety Administration (PHMSA) are currently under development. In 2016,

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PHMSA issued a notice of proposed rulemaking titled the "Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments." In 2019, PHMSA issued the first of three portions of the rulemaking which went into effect on July 1, 2020 and includes up to a 15-year timeline for compliance. The second portion of the rule known as the gas gathering rule was issued in late 2021, and final rulemaking titled "The Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments" was issued in August 2022. A Gas Pipeline Leak Detection rule is expected to be issued in 2023. NW Natural intends to continue to work diligently with industry associations as well as federal and state regulators to support the safety of the system and compliance with new laws and regulations. We expect the costs associated with compliance with federal, state, and local laws and regulations to be recovered in rates. North Mist Gas Storage Facility In May 2019, NW Natural completed an expansion of its existing gas storage facility near Mist, Oregon. The North Mist facility provides long-term, no-notice underground gas storage service and is dedicated solely to Portland General Electric (PGE) under a 30-year contract with options to extend up to an additional 50 years upon mutual agreement of the parties. PGE uses the facility to fuel its gas-fired electric power generation facilities, which backs up PGE's variable load of renewable energy on the electric grid. North Mist includes a reservoir providing 4.1 Bcf of available storage, an additional compressor station with a contractual capacity of 120,000 dekatherms of gas deliverability per day, no-notice service that can be drawn on rapidly, and a 13-mile pipeline to connect to PGE's Port Westward gas plants in Clatskanie, Oregon. Upon placement into service in May 2019, the facility was included in rate base under an established tariff schedule with revenues recognized consistent with the schedule. Billing rates are updated annually to the forecasted depreciable asset level and forecasted operating expenses. While there are additional expansion opportunities in the Mist storage field, any expansion would be based on market demand, cost effectiveness, available financing, receipt of future permits, and other rights. OTHER ##TABLE_START ##TABLE_ENDCertain businesses and activities of NW Holdings and NW Natural are aggregated and reported as other for segment reporting purposes. NW Natural The following businesses and activities are aggregated and reported as other under NW Natural, a wholly-owned subsidiary of NW Holdings: 5.8 Bcf of the Mist gas storage facility contracted to other utilities and third-party marketers; natural gas asset management activities; and appliance retail center operations. Mist Gas Storage The Mist gas storage facility began operations in 1989. It is a 17.5 Bcf facility with 11.7 Bcf used to provide gas storage for the NGD business. The remaining 5.8 Bcf of the facility is contracted with other utilities and third-party marketers with these results reported in other. In 2022, NW Natural utilized 0.5 Bcf of increased storage capacity realized through reservoir expansion during more than 15 years of delta pressure operations. This change increased the working gas capacity from 17.0 Bcf in 2021 to 17.5 Bcf in 2022. The overall facility consists of seven depleted natural gas reservoirs, 22 injection and withdrawal wells, a compressor station, dehydration and control equipment, gathering lines, and other related facilities. The capacity at Mist serving other utilities and third-party marketers provides multi-cycle gas storage services to customers in the interstate and intrastate markets. The interstate storage services are offered under a limited jurisdiction blanket certificate issued by FERC. Under NW Natural's interstate storage certificate with FERC, NW Natural is required to file either a petition for rate approval or a cost and revenue study every five years to change or justify maintaining the existing rates for the interstate storage service. Intrastate firm storage services in Oregon are offered under an OPUC-approved rate schedule as an optional service to certain eligible customers. Gas storage revenues from the 5.8 Bcf are derived primarily from firm service customers who provide energy-related services, including natural gas distribution, electric generation, and energy marketing. The Mist facility benefits from limited competition as there are few storage facilities in the Pacific Northwest region. Therefore, NW Natural is able to acquire high-value, multi-year contracts. Asset Management Activities NW Natural contracts with an independent energy marketing company to provide asset management services, primarily through the use of natural gas commodity exchange agreements and natural gas pipeline capacity release transactions. The results of these activities are included in other, except for the asset management revenues allocated to NGD business customers pursuant to regulatory agreements, which are reported in the NGD segment. NW Holdings These include the following businesses and activities aggregated under NW Holdings: NW Natural Water Company, LLC (NWN Water) and its water and wastewater utility operations; NWN Water's equity investment in Avion Water Company, Inc.; NW Natural Renewables Holdings, LLC and its non-regulated renewable natural gas activities; a minority interest in the Kelso-Beaver Pipeline held by our wholly-owned subsidiary NNG Financial Corporation (NNG Financial); and holding company and corporate activities, including business development activities, as well as adjustments made in consolidation. NW Natural Water NWN Water currently serves an estimated 155,000 people through approximately 62,500 water and wastewater connections across five states. NWN Water continues to grow though customer additions within or near its service territories, and continues to pursue acquisitions. For recently acquired water utilities, see further discussion about the status of water general rate cases in Part II, Item 7, "Results of OperationsRegulatory Matters Water General Rate Cases ." The water and wastewater utilities primarily serve residential and commercial customers. Water distribution operations are seasonal in nature with peak demand during warmer summer months, while wastewater is less seasonally affected. Entities generally operate in exclusive service territories with no direct competitors. Water distribution customer rates are regulated by state utility commissions while the wastewater businesses we own consist of some state regulated systems and some systems that are not rate regulated by utility commissions. NW Natural Renewables NW Natural Renewables is a newly formed non-regulated subsidiary of NW Natural Holdings established to invest in renewable energy through the production and supply of

lower-carbon fuels. NW Natural Renewables' first project is with a subsidiary of EDL, a global producer of sustainable distributed energy. In September 2021, a subsidiary of NW Natural Renewables and a subsidiary of EDL executed agreements, whereby the subsidiary of NW Natural Renewables committed $50 million toward the development of two production facilities that are designed to convert landfill waste gases to RNG and connect gas production to existing regional pipeline networks. Testing and commissioning of the production facilities is expected to occur in the spring of 2023. Alongside these development agreements, a subsidiary of NW Natural Renewables and a subsidiary of EDL executed agreements designed to secure a 20-year supply of RNG produced from the facilities for NW Natural Renewables. In 2022, NW Natural Renewables executed a four-year off-take agreement with a counterparty for the near-term RNG production. NW Natural Renewables is currently in discussions with other counterparties to contract the remaining RNG production under long-term contracts. ENVIRONMENTAL MATTERS ##TABLE_START ##TABLE_ENDProperties and Facilities NW Natural owns, or previously owned, properties and facilities that are currently being investigated that may require environmental remediation and are subject to federal, state, and local laws and regulations related to environmental matters. These laws and regulations may require expenditures over a long time frame to address certain environmental impacts. Estimates of liabilities for environmental costs are difficult to determine with precision because of the various factors that can affect their ultimate disposition. These factors include, but are not limited to, the following: the complexity of the site; changes in environmental laws and regulations at the federal, state, and local levels; the number of regulatory agencies or other parties involved; new technology that renders previous technology obsolete, or experience with existing technology that proves ineffective; the level of remediation required; variations between the estimated and actual period of time that must be dedicated to respond to an environmentally-contaminated site; and the application of environmental laws that impose joint and several liabilities on all potentially responsible parties. NW Natural has received recovery of a portion of such environmental costs through insurance proceeds, seeks the remainder of such costs through customer rates, and believes recovery of these costs is probable. In both Oregon and Washington, NW Natural has mechanisms to recover expenses. Oregon recoveries are subject to an earnings test. See Part II, Item 7, "Results of OperationsRegulatory MattersRate Mechanisms Environmental Cost Deferral and Recovery ", and Note 2 and Note 17 of the Consolidated Financial Statements in Item 8 of this report for more information. Greenhouse Gas Matters For information concerning greenhouse gas matters, see Part II, Item 7, Results of OperationsEnvironmental Regulation and Legislation Matters. HUMAN CAPITAL ##TABLE_START ##TABLE_ENDOur core values of integrity, safety, caring, service ethic, and environmental stewardship guide how we engage with customers, stakeholders, shareholders, and communities. We actively work to foster these values in our employee culture and to nurture an inclusive and equitable environment that provides opportunities, prioritizes health and safety, encourages respect and trust, and supports growth and learning. We aim to recruit and retain employees who share our core values and reect our communities. Employees At December 31, 2022, our workforce consisted of the following: ##TABLE_START NW Natural: Unionized employees (1) 575 Non-unionized employees 574 Total NW Natural 1,149 Other Entities: Water and wastewater company employees 105 Other 4 Total other entities 109 Total Employees 1,258 ##TABLE_END(1) Members of the Office and Professional Employees International Union (OPEIU) Local No. 11, AFL-CIO. NW Natural's labor agreement with members of OPEIU covers wages, benefits, and working conditions. In November 2019, NW Natural's unionized employees ratified a collective bargaining agreement that took effect on December 1, 2019 and extends to May 31, 2024, and thereafter from year to year unless either party serves notice of its intent to negotiate modifications to the collective bargaining agreement. During calendar year 2022, NW Natural did not incur any work stoppages (strikes or lockouts), and therefore, experienced zero idle days for the year. Certain subsidiaries may receive services from employees of other subsidiaries. When such services involve regulated entities, those entities receiving services reimburse the entity providing services pursuant to shared services agreements, as applicable. Safety Safety is one of our greatest responsibilities to employees. In managing the business, we strive to foster a safety culture focused on prevention, open communication, collaboration, and a strong service and safety ethic. We believe employee safety is critical to our success. A portion of executives compensation is tied to achieving our safety metrics, and our Board of Directors regularly reviews company safety metrics. NW Naturals health and safety policies and procedures are designed to comply with all applicable regulations, but we also work to go beyond compliance by striving to incorporate industry best practices and benchmarking. As part of our commitment to employee health and safety, we maintain regular training programs, emergency preparedness procedures, and specic training and procedures to identify hazards and handle high-risk emergency situations. Employees complete classroom instruction and hands-on, scenario-based training at our training facility in Oregon that allows employees to experience realistic situations in a controlled environment. We also host natural gas safety training events for rst responders, which are designed to prepare those first responders and NW Natural field employees to deliver an integrated, seamless response in the event of an emergency that involves or affects the natural gas system. We navigated, and continue to navigate, the COVID-19 pandemic to help keep people safe. We also implemented a new learning management system that went live in early 2021 and provides more efficiency and flexibility in how we train. Employee Benefits and Support To attract employees and meet the needs of our workforce, NW Natural strives to offer competitive compensation and benefits packages to employees. The benefits package options vary depending on type of employee and date of hire. NW Natural continuously looks for ways to support employees work-life balance and well-being and this is reflected in physical, mental and financial wellness programs to meet the needs of our employees and help them care for their families. Benefits available to employees during 2022 included, among others:

healthcare and other insurance coverages, wellness resources, retirement and savings plans, paid time off programs, and flexible and hybrid work schedules, where possible, employee resource groups, and culture and community-focused resources and opportunities, and employee recognition programs and discounts. Talent Attraction and Development In order to implement our business strategy and serve our customers, we depend upon our continuing ability to attract and retain diverse, talented professionals and a technically skilled workforce, and being able to transfer the knowledge and expertise of our workforce to new and increasingly diverse employees as our largely older workforce retires. A significant portion of our workforce is currently eligible or will reach retirement eligibility within the next five years, and therefore, we are focused on efforts to attract, train, and retain appropriately qualified and skilled workers to prevent loss of institutional knowledge or skills gaps. NW Natural seeks to provide its employees with growth and development opportunities through programs designed to build skills and relationships. These programs currently include: (i) a culturally relevant mentoring program that creates opportunities for career growth by building relationships; (ii) a tuition assistance program for qualified educational pursuits; (iii) an internal class that provides participants with a big-picture understanding of the industry and company operations, equipping them to see how they contribute to NW Naturals success and identify opportunities for career growth; (iv) internal and external continuing educational courses relevant to areas of expertise; and (v) ongoing management and leadership training programs. We regularly monitor employee engagement and satisfaction through a variety of tools, including our annual engagement survey that is designed to enable company leaders to gather valuable feedback and guidance from employees. Diversity, Equity and Inclusion We have a longstanding commitment to creating a diverse and inclusive culture that reflects and supports the communities we serve, and believe a diverse, equitable, and inclusive workforce at all levels contributes to long-term success. Our efforts in recruiting, promoting, and retaining diverse talent, building inclusive teams, and creating a culture that embraces differences are at the core of our workforce strategy. To attract diverse candidates, we work with community partners to help promote awareness of job opportunities within diverse communities. We have employee-led groups that develop programs and activities that build awareness around issues important to their co-workers, families, customers, and our community. Groups include the Diversity, Equity Inclusion Council, Women's Network, African American, Rainbow Alliance (LGBTQ+), Veterans, Somos Unidos (Latinx), Asian American, and Neurodiversity employee resource groups, Wellness Advisory Committee, and Sustainability and Equity Engagement Team. We also continue to emphasize diversity, equity and inclusion values through employee training and education, including expanded diversity training as part of new hire onboarding and other diversity, equity, and inclusion education that occurs throughout the year. An area of focus going forward is to understand and increase awareness of internal systems and structures that could limit representation and equity for underrepresented employees. To that end, we are working toward revising and refocusing new manager and new hire training to include implicit bias, diversity, equity and inclusion, and anti-racism education. INFORMATION ABOUT OUR EXECUTIVE OFFICERS ##TABLE_START ##TABLE_ENDFor information concerning executive officers, see Part III, Item 10. AVAILABLE INFORMATION ##TABLE_START ##TABLE_ENDNW Holdings and NW Natural file annual, quarterly and current reports and other information with the Securities and Exchange Commission (SEC). The SEC maintains an Internet site where reports, proxy statements, and other information filed can be read, copied, and requested online at its website (www.sec.gov). In addition, we make available, free of charge, on our website (www.nwnaturalholdings.com), our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) and proxy materials filed under Section 14 of the Securities Exchange Act of 1934, as amended (Exchange Act), as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. We intend to use our website as a means of disclosing material non-public information and for complying with our disclosure obligations under Regulation FD. Accordingly, investors should monitor our website, in addition to following our press releases, SEC filings and public conference calls and webcasts. We have included our website address as an inactive textual reference only. Information contained on our website is not incorporated by reference into this annual report on Form 10-K. NW Holdings and NW Natural have adopted a Code of Ethics for all employees, officers, and directors that is available on our website. We intend to disclose revisions and amendments to, and any waivers from, the Code of Ethics for officers and directors on our website. Our Corporate Governance Standards, Director Independence Standards, charters of each of the committees of the Board of Directors, and additional information about NW Holdings and NW Natural are also available at the website. Copies of these documents may be requested, at no cost, by writing or calling Shareholder Services, Northwest Natural Holding Company, 250 S.W. Taylor Street, Portland, Oregon 97204, telephone 503-220-2402. ITEM 1A. RISK FACTORS NW Holdings and NW Naturals business and financial results are subject to a number of risks and uncertainties, many of which are not within our control, which could adversely affect our business, financial condition, and results of operations. Additional risks and uncertainties that are not currently known to us or that are not currently believed by us to be material may also harm our businesses, financial condition, and results of operations. When considering any investment in NW Holdings or NW Naturals securities, investors should carefully consider the following information, as well as information contained in the caption "Forward-Looking Statements", Item 7A, and our other documents filed with the SEC. This list is not exhaustive and the order of presentation does not reflect managements determination of priority or likelihood. Additionally, our listing of risk factors that primarily affects one of our businesses does not mean that such risk factor is inapplicable to our other businesses. Legal, Regulatory and Legislative Risks REGULATORY RISK. Regulation of NW Holdings and NW Naturals regulated businesses, including changes in the regulatory environment, failure of regulatory authorities to approve rates which provide for timely recovery of costs and an adequate return on invested capital, or an unfavorable outcome in regulatory proceedings may adversely impact NW Holdings and NW Naturals financial condition and results of operations. The OPUC and WUTC have general regulatory authority over NW Naturals gas business in Oregon and Washington. NW Holdings regulated water utility businesses are generally regulated by the public utility commission in the state in which a water business is located. These public utility commissions have broad regulatory authority, including: the rates charged to customers; authorized rates of return on rate base, including ROE; the amounts and types of securities that may be issued by our regulated utility companies, like NW Natural; services our regulated utility companies provide and the manner in which they provide them; the nature of investments our utility companies make; deferral and recovery of various expenses, including, but not limited to, pipeline replacement, environmental remediation costs, capital and information technology investments, commodity hedging expense, and certain employee benefit expenses such as pension costs; transactions with affiliated interests; regulatory adjustment mechanisms such as weather adjustment mechanisms, and other matters. The OPUC also regulates actions investors may take with respect to our utility companies, NW Natural and NW Holdings. Similarly, FERC has regulatory authority over NW Naturals interstate storage services. Expansion of our businesses generally results in regulation by other regulatory authorities. For example, certain of NW Holdings water companies are regulated in Idaho, Texas and Arizona. The costs that are deemed recoverable in rates and prices regulators allow us to charge for regulated utility service, and the maximum FERC-approved rates FERC authorizes us to charge for interstate storage and related transportation services, are the most significant factors affecting both NW Naturals and NW Holdings financial position, results of operations and liquidity. State utility regulators have the authority to disallow recovery of costs they find imprudently incurred or otherwise disallowed, and rates that regulators allow may be insufficient for recovery of costs we incur. We expect to continue to make expenditures to expand, improve and safely operate our gas and water utility distribution and gas storage systems, and to work toward decarbonizing our gas systems. Regulators can deny recovery of those costs. Furthermore, while each applicable state regulator has established an authorized rate of return for our regulated utility businesses, we may not be able to achieve the earnings level authorized. Moreover, in the normal course of business we may place assets in service or incur higher than expected levels of operating expense before rate cases can be filed to recover those costs (this is commonly referred to as regulatory lag). The failure of any regulatory commission to approve requested rate increases on a timely basis to recover costs or to allow an adequate return could adversely impact NW Holdings or NW Naturals financial condition, results of operations and liquidity. As companies with regulated utility businesses, we frequently have dockets open with our regulators. The regulatory proceedings for these dockets typically involve multiple parties, including governmental agencies, consumer, environmental, and other advocacy groups, and other third parties. Each party advocates for the interests that they represent, which may include lower rates, additional regulatory oversight over the company, limitations on growth or phasing out of the gas system, decisions that favor electrification, or advancing other interests. We cannot predict the timing or outcome of these proceedings, or the effects of those outcomes on NW Holdings and NW Naturals results of operations and financial condition. REGULATION, COMPLIANCE AND TAXING AUTHORITY RISK. NW Holdings and NW Natural are subject to governmental regulation, and compliance with local, state and federal requirements, including taxing requirements, and unforeseen changes in or interpretations of such requirements could affect NW Holdings or NW Naturals financial condition and results of operations. NW Holdings and NW Natural are subject to regulation by federal, state and local governmental authorities. We are required to comply with a variety of laws and regulations and to obtain authorizations, permits, approvals and certificates from governmental agencies in various aspects of our business. Significant changes in federal, state, or local governmental leadership can accelerate or amplify changes in existing laws or regulations, or the manner in which they are interpreted or enforced. For instance, the 2020 United States Presidential election resulted in leadership changes in many federal administrative agencies and resulted in a wide range of new policies, executive orders, rules, initiatives and other changes to fiscal, tax, regulation, environmental, climate and other federal policies, many of which have components that affect the energy sector. Similarly, although party leadership in Oregon and Washington did not significantly change in the most recent election, we could continue to face significant legislative, regulatory and other policy changes in the jurisdictions in which we operate. In addition, foreign governments may implement changes to their policies, in response to changes to U.S. policy or otherwise. Although we cannot predict the impact, if any, of these changes to our businesses, they could adversely affect NW Holdings or NW Naturals financial condition and results of operations. Until we know what policy changes are made and how those changes impact our businesses and the business of our competitors over the long term, we will not know if, overall, we will benefit from them or will be negatively affected by them. We cannot predict changes in laws, regulations, interpretations or enforcement or the impact of such changes. Additionally, any failure to comply with existing or new laws and regulations could result in fines, penalties or injunctive measures. For example, under the Energy Policy Act of 2005, the FERC has civil authority under the Natural Gas Act to impose penalties for current violations of nearly $1.5 million per day for each violation. In addition, as the regulatory environment for our businesses increases in complexity, the risk of inadvertent noncompliance may also increase. Changes in regulations, the imposition of additional regulations, and the failure to comply with laws and regulations could negatively influence NW Holdings or NW Naturals operating environment and results of operations. Additionally, changes in federal, state, local or foreign tax laws and their related regulations, or differing interpretations or enforcement of applicable law by a federal, state, local or foreign taxing authority, could result in substantial cost to us and negatively affect our results of operations. Tax law and its related regulations and case law are inherently complex and dynamic. Disputes over interpretations of tax laws may be settled with the taxing authority in examination, through programs like the Compliance Assurance Process (CAP), upon appeal or through litigation. Our judgments may include reserves for potential adverse outcomes regarding tax positions that have been or plan to be taken that may be subject to challenge by taxing authorities. Changes in laws, regulations or adverse judgments and the inherent difficulty in quantifying potential tax effects of business decisions may negatively affect NW Holdings or NW Naturals financial condition and results of operations. Furthermore, certain tax assets and liabilities, such as deferred tax assets and regulatory tax assets and liabilities, are recognized or recorded by NW Holdings or NW Natural based on certain assumptions and determinations made based on available evidence, such as projected future taxable income, tax-planning strategies, and results of recent operations. If these assumptions and determinations prove to be incorrect, the recorded results may not be realized, which may negatively impact the financial results of NW Holdings and NW Natural. There is uncertainty as to how our regulators will reflect the impact of the legislation and other government regulation in rates. The resulting ratemaking treatment may negatively affect NW Holdings or NW Naturals financial condition and results of operations. REPUTATIONAL RISKS. Customers', legislators', regulators' and other third parties opinions of NW Holdings and NW Natural are affected by many factors, including system and fuel reliability and safety, protection of customer information, rates, actual or perceived effects of our products, media coverage, and public sentiment. To the extent that customers, legislators, or regulators have or develop a negative opinion of our businesses, NW Holdings and NW Naturals financial position, results of operations and cash flows could be adversely affected. A number of factors can affect customers, legislators, regulators, and other third parties perception of us or our business including: service interruptions or safety concerns due to failures of equipment or facilities or from other causes, and our ability to promptly respond to such failures; our ability to safeguard sensitive customer information; the timing and magnitude of rate increases; and volatility of rates. Customers', legislators', and regulators' opinions of us can also be affected by media coverage, including the proliferation of social media, which may include information, whether factual or not, that could damage the perception of natural gas, our brand, or our reputation. Although we believe that natural gas serves an important role in helping our region reduce GHG emissions and move to a resilient lower-carbon energy system, certain advocacy groups have opposed the use of natural gas as a fuel source altogether and have pursued policies that limit, restrict, or impose additional costs on, the use of natural gas in a variety of contexts. Concerns raised about the use of natural gas include the potential for natural gas explosions or delivery disruptions, methane leakage along production, transportation and delivery systems, and end-use equipment, and contribution of natural gas energy use to GHG emission levels and global warming. Similarly, concerns have also been raised regarding the use of RNG or hydrogen in place of natural gas. In addition, studies and claims by advocacy groups contend that there are detrimental indoor public health effects associated with the use of natural gas, which may also impact public perception. Shifts in public sentiment due to these concerns or others that may be raised may impact further legislative initiatives, regulatory actions, and litigation, as well as behaviors and perceptions of customers, investors, lawmakers, and regulators. If customers, legislators, regulators, or other third parties have or develop a negative opinion of us and our services, or of natural gas as an energy source generally, this could make it more difficult for us to achieve policy, legislative or regulatory outcomes supportive of our business. Negative opinions could also result in reduced customer growth, sales volumes reductions, increased use of other sources of energy, or difficulties in accessing capital markets. Any of these consequences could adversely affect NW Holdings or NW Naturals financial position, results of operations and cash flows. REGULATORY ACCOUNTING RISK. In the future, NW Holdings or NW Natural may no longer meet the criteria for continued application of regulatory accounting practices for all or a portion of our regulated operations. If we can no longer apply regulatory accounting, we could be required to write off our regulatory assets and precluded from the future deferral of costs not recovered through rates at the time such amounts are incurred, even if we are expected to recover these amounts from customers in the future. COVID-19 Risk PUBLIC HEALTH RISK . The continuation of the novel coronavirus (COVID-19) and the resulting economic conditions, or the emergence of other epidemic or pandemic crises, could materially and adversely affect NW Holdings and NW Naturals business, results of operations, or financial condition. The novel coronavirus (COVID-19), which was declared a pandemic by the World Health Organization in March 2020, has resulted in widespread and severe global, national and local economic and societal disruptions. As recovery from the COVID-19 pandemic continues, resurgences or mutations of the virus, could ultimately adversely affect our business by, among other things: impacting the health, safety, productivity and availability of our employees and contractors; disrupting our access to capital markets or increasing costs of capital affecting our liquidity in the future; reducing demand for natural gas, particularly from commercial and industrial customers that are suffering slow-downs or ultimately close completely due to pandemic effects; reducing customer growth and new meter additions due to less economic, construction or conversion activity; limiting our ability to collect on overdue accounts or disconnect gas service for nonpayment, beyond an amount or period of time acceptable to us; increasing our operating costs for emergency supplies, personal protective equipment, cleaning services and supplies, remote technology and other specific needs; impacting our capital expenditures if construction activities are suspended or delayed; sickening or causing a mandatory quarantine of a large percentage of our workforce, or key workgroups with specialized skill sets, impairing our ability to perform key business functions or execute our business continuity plans; impacting our or our contractors or suppliers ability to recruit and retain qualified personnel or otherwise impairing the functioning of our supply chain or ability to rely on third parties or business partners; adversely affecting the asset values of NW Naturals defined benefit pension plan or causing a failure to maintain sustained growth in pension investments over time, increasing our contribution requirements; limiting, delaying or curtailing entirely, public utility commissions ability to approve or authorize applications or other requests we may make with respect to our regulated businesses; increasing volatility in the price of natural gas; and creating additional cybersecurity vulnerabilities due to ongoing heavy reliance on remote working. Additionally, the long-term effects of COVID-19 or other pandemics could create prolonged unfavorable economic conditions, slowed economic growth, inflation, which may continue to rise, or an economic recession that may result in or be accompanied by unprecedented unemployment rates and declines in the value of certain assets, adversely affecting the income and financial resources of many domestic households and businesses. It is unclear whether governmental responses to these conditions will lessen the severity or duration of any economic effects. Our operational and financial results would likely be affected by such economic conditions. Less new housing construction, fewer conversions to natural gas, higher levels of residential foreclosures and vacancies, and personal and business bankruptcies or reduced spending could all negatively affect our financial condition and results of operations. The ultimate long-term impact of COVID-19 on our business cannot be predicted and will depend on factors beyond our knowledge or control, including resurgences of the pandemic and residual economic effects, actions taken to mitigate its effects, and the extent to which normal economic and operating conditions can continue. Any of these factors could have an adverse effect on our business, outlook, financial condition, and results of operations and cash flows, which could be significant. Growth and Strategic Risks STRATEGIC TRANSACTION RISK. NW Holdings and NW Naturals ability to successfully complete strategic transactions, including mergers, acquisitions, combinations, divestitures, joint ventures, business development projects or other strategic transactions is subject to significant risks, including the risk that required regulatory or governmental approvals may not be obtained, risks relating to unknown problems or liabilities or problems or liabilities undisclosed to us, and the risk that for these or other reasons, we may be unable to achieve some or all of the benefits that we anticipate from such transactions, which could adversely affect NW Holdings or NW Naturals financial condition, results of operations, and cash flows. From time to time, NW Holdings and NW Natural have pursued and may continue to pursue strategic transactions including mergers, acquisitions, combinations, divestitures, joint ventures, business development projects or other strategic transactions, including, but not limited to, investments in RNG projects on a regulated basis by NW Natural and on a non-regulated basis by NW Holdings, as well as acquisitions by NW Holdings in the water and wastewater sectors. Any such transactions involve substantial risks, including the following: such transactions that are contracted for may fail to close for a variety of reasons; the result of such transactions may not produce revenues, earnings or cash flow at anticipated levels, which could, among other things, result in the impairment of any investments or goodwill associated with such transactions; acquired businesses or assets could have environmental, permitting, or other problems for which contractual protections prove inadequate; there may be difficulties in integration or operation costs of new businesses; there may exist liabilities that were not disclosed to us, that exceed our estimates, or for which our rights to indemnification from the seller are limited; we may be unable to obtain the necessary regulatory or governmental approvals to close a transaction or receive approvals granted subject to terms that are unacceptable to us; we may be unable to achieve the anticipated regulatory treatment of any such transaction as part of the transaction approval or subsequent to closing the transaction; or we may be unable to avoid a disposition of assets for a price that is less than the book value of those assets. One or more of these risks could affect NW Holdings and NW Naturals financial condition, results of operations, and cash flows. BUSINESS DEVELOPMENT RISK. NW Holdings and NW Naturals business development projects may not be successful or may encounter unanticipated obstacles, costs, changes or delays that could result in a project being unsuccessful or becoming impaired, which could negatively impact NW Holdings or NW Naturals financial condition, results of operations and cash flows. Business development projects involve many risks. We are currently engaged in several business development projects, including, but not limited to, several water, wastewater and RNG projects. We may also engage in other business development projects such as investments in additional long-term gas reserves, non-regulated investments in RNG projects, and purchasing, marketing and reselling of RNG and its associated attributes, CNG refueling stations, power to gas or hydrogen projects or other similar projects. Our business development activities are subject to uncertainties and changed circumstances and may not reach the scale expected, be successful or perform as anticipated. Additionally, we may not be able to obtain required governmental permits and approvals to complete our projects in a cost-efficient or timely manner, potentially resulting in delays or abandonment of the projects. We could also experience issues such as: technological challenges; ineffective scalability;failure to achieve expected outcomes; unsuccessful business models; startup and construction delays; construction cost overruns; disputes with contractors; the inability to negotiate acceptable agreements such as rights-of-way, easements, construction, gas supply or other material contracts; changes in customer demand, perception or commitment; public opposition to projects; marketing risk and changes in market regulation, behavior or prices, market volatility or unavailability,including markets for RNG and its associated attributes or other environmental attributes; the inability to receive expected tax or regulatory treatment; and operating cost increases. Additionally, we may be unable to finance our business development projects at acceptable costs or within a scheduled time frame necessary for completing the project. Any of the foregoing risks, if realized, could result in business development efforts failing to produce expected financial results and the project investment becoming impaired, and such failure or impairment could have an adverse effect on NW Holdings or NW Naturals financial condition and results of operations. JOINT PARTNER RISK. Investing in business development projects through partnerships, joint ventures or other business arrangements affects our ability to manage certain risks and could adversely impact NW Holdings or NW Naturals financial condition, results of operations and cash flows. We use joint ventures and other business arrangements to manage and diversify the risks of certain development projects, including NW Naturals gas reserves agreements and certain RNG projects. NW Holdings or NW Natural currently has and may further acquire or develop part-ownership interests in other projects in the future, including but not limited to, natural gas, water, wastewater, RNG, or hydrogen projects. Under these arrangements, we may not be able to fully direct the management and policies of the business relationships, and other participants in those relationships may act contrary to our interests, including making operational decisions that could negatively affect our costs and liabilities. In addition, other participants may withdraw from the project, divest important assets, become financially distressed or bankrupt, or have economic or other business interests or goals that are inconsistent with ours. We have in the past and may in the future become involved in disputes with our business partners, which could result in additional cost or divert managements attention. NW Naturals gas reserves arrangements, which operate as a hedge backed by physical gas supplies, involve a number of risks, including: gas production that is significantly less than the expected volumes, or no gas volumes; operating costs that are higher than expected; inherent risks of gas production, including disruption to operations or a complete shut-in of the field; and one or more participants in one of these gas reserves arrangements becoming financially insolvent or acting contrary to NW Naturals interests. For example, while Jonah Energy, the counterparty in NW Naturals gas reserves arrangement, has recently issued asset-backed notes that are rated by credit agencies, Jonah Energy has previously experienced several credit rating downgrades and did not maintain any credit ratings for much of 2022. Although NW Natural intends to continue monitoring Jonah Energys financial condition and take appropriate actions to preserve NW Naturals interests, it does not control Jonah Energys financial condition or continued performance under the gas reserves arrangement. The cost of the original gas reserves venture is currently included in customer rates and additional wells under that arrangement are recovered at specific costs, the occurrence of one or more of these risks could affect NW Naturals ability to recover this hedge in rates. Further, new gas reserves arrangements have not been approved for inclusion in rates, and regulators may ultimately determine to not include all or a portion of future transactions in rates. The realization of any of these situations could adversely impact NW Holdings or NW Naturals financial condition, results of operations and cash flows. CUSTOMER GROWTH RISK. NW Holdings and NW Naturals NGD margin, earnings and cash flow may be negatively affected if we are unable to sustain customer growth rates in our NGD segment. NW Naturals NGD margins and earnings growth have largely depended upon the sustained growth of its residential and commercial customer base due, in part, to the new construction housing market, conversions of customers to natural gas from other energy sources and growing commercial use of natural gas. Building codes recently enacted and others under consideration in our territory may have the effect of reducing our natural gas customer growth rate. For example, effective February 1, 2021, building codes in Washington state require new residential homes to achieve higher levels of energy efficiency based on specified carbon emissions assumptions, which calculate electric appliances to have lower on-site GHG emissions than comparable gas appliances. This increases the cost of new home construction incorporating natural gas depending on a number of factors including home size, equipment configurations, and building envelope measures. Additionally, the Washington State Building Code Council (SBCC) voted in April 2022 to include updates in the state commercial building energy code that are expected to restrict or eliminate the use of gas space and water heating in new commercial construction. In early November, the SBCC voted to include updates to the state residential building energy code that restrict the use of gas space and water heating in residential construction, with certain exceptions including for natural gas-fired heat pumps and hybrid fuel systems.The SBBC commercial and residential rules are expected to become effective July 1, 2023. Certain jurisdictions in Oregon and the State of Oregon are considering similar measures. While we expect these types of codes to be subject to legal challenge, we cannot predict the outcome of any such challenge. Insufficient customer growth, for economic, political, public perception, policy, or other reasons could adversely affect NW Holdings or NW Naturals utility margin, earnings and cash flows. RISK OF COMPETITION. Our NGD business is subject to increased competition which could negatively affect NW Holdings or NW Naturals results of operations. In the residential and commercial markets, NW Naturals NGD business competes primarily with suppliers of electricity, fuel oil, and propane. In the industrial market, NW Natural competes with suppliers of all forms of energy. Competition among these forms of energy is based on price, efficiency, reliability, performance, market conditions, technology, federal, state and local governmental regulation, actual and perceived environmental impacts, and public perception. Technological improvements such as electric heat pumps, batteries or other alternative technologies, or building code restrictions affecting the ability to use certain gas appliances, could erode NW Naturals competitive advantage. If natural gas prices are high relative to other energy sources, or if the cost, environmental impact or public perception of such other energy sources improves relative to natural gas, it may negatively affect NW Naturals ability to secure new customers or retain our existing residential, commercial and industrial customers, which could have a negative impact on our customer growth rate and NW Holdings and NW Naturals results of operations. Our natural gas storage operations compete primarily with other storage facilities and pipelines. Increased competition in the natural gas storage business could reduce the demand for our natural gas storage services, drive prices down for our storage business, and adversely affect our ability to renew or replace existing contracts at rates sufficient to maintain current revenues and cash flows, which could adversely affect NW Holdings and NW Naturals financial condition, results of operations and cash flows. Operational Risks OPERATING RISK. Transporting and storing natural gas and distributing natural gas and water involves numerous risks that may result in accidents and other operating risks and costs, some or all of which may not be fully covered by insurance, and which could adversely affect NW Holdings or NW Naturals financial condition, results of operations and cash flows. NW Holdings and NW Natural are subject to all of the risks and hazards inherent in the businesses of gas and RNG transmission, distribution and storage, water distribution, and wastewater services including: earthquakes, wildfires, floods, storms, landslides and other severe weather incidents and natural hazards; leaks or losses of natural gas or RNG, water or wastewater, or contamination of natural gas, RNG or water by chemicals or compounds, as a result of the malfunction of equipment or facilities or otherwise; damages from third parties; operator errors; negative performance by our storage reservoirs, facilities, or wells that could cause us to fail to meet expected or forecasted operational levels or contractual commitments to our customers or other third parties; problems maintaining, or the malfunction of, pipelines, biodigester facilities, wellbores and related equipment and facilities that form a part of the infrastructure that is critical to the operation of our gas and water distribution, wastewater services, RNG and gas storage facilities; presence of chemicals or other compounds in RNG or natural gas that could adversely affect the performance of the system or end-use equipment; collapse of underground storage reservoirs; inadequate supplies of RNG, natural gas or water or contamination of water supplies; operating costs that are substantially higher than expected; supply chain disruptions, including unexpected price increases, or supply restrictions beyond the control of our suppliers; migration of gas through faults in the rock or to some area of the reservoir where existing wells cannot drain the gas effectively, resulting in loss of the gas; blowouts (uncontrolled escapes of gas from a pipeline or well) or other accidents, fires and explosions; and risks and hazards inherent in the drilling operations associated with the development of gas storage facilities, and wells. For example, TC Pipelines, LP (TC Pipelines) has identified the presence of a chemical substance, dithiazine, at several facilities on the system of its subsidiary, Gas Transmission Northwest (GTN), and those of some upstream and downstream connecting pipeline facilities. A portion of NW Naturals gas supplies from Canada are transported on GTNs pipelines. TC Pipelines reports that dithiazine can drop out of gas streams in a powdery form at some points of pressure reduction (for example, at a regulator), and that in incidents where a sufficient quantity of the material accumulates in certain places, improper functioning of equipment can occur, which can result in increased preventative and corrective action costs. While NW Natural has not detected significant quantities of dithiazine on its system to date, we continue to monitor and could discover increased levels of dithiazine or other compounds on NW Naturals system that could affect the performance of the system or end-use equipment. These and other operational risks could result in disruption of service, personal injury or loss of human life, damage to and destruction of property and equipment, pollution or other environmental damage, breaches of our contractual commitments, and may result in curtailment or suspension of operations, which in turn could lead to significant costs and lost revenues. Further, because our pipeline, storage and distribution facilities are in or near populated areas, including residential areas, commercial business centers, and industrial sites, any loss of human life or adverse financial outcomes resulting from such events could be significant. We could be subject to lawsuits, claims, and criminal and civil enforcement actions. Additionally, we may not be able to maintain the level or types of insurance we desire, and the insurance coverage we do obtain may contain large deductibles or fail to cover certain hazards or cover all potential losses. The occurrence of any operating risks not covered by insurance could adversely affect NW Holdings or NW Naturals financial condition, results of operations and cash flows. SAFETY REGULATION RISK. NW Holdings and NW Natural may experience increased federal, state and local regulation of the safety of our systems and operations, which could adversely affect NW Holdings or NW Naturals operating costs and financial results. The safety and protection of the public, our customers and our employees is and will remain our top priority. We are committed to consistently monitoring, maintaining, and upgrading our distribution systems and storage operations to ensure that RNG, natural gas and water is acquired, stored and delivered safely, reliably and efficiently. Natural gas operators are subject to robust, ongoing federal, state and local regulatory oversight, which intensifies in response to incidents. For example, the 2020 Protecting our Infrastructure of Pipelines and Enhancing Safety Act (PIPES Act) prompted PHSMA to issue three new rulemakings impacting transmission lines, gathering lines, and valve automation in response to past incidents in other parts of the country. Proposed rulemakings planned for 2023 by the Pipeline and Hazardous Materials Safety Administration (PHMSA), include regulations related to the detection and repair of leaks and safety of gas distribution pipelines. In addition, our workplaces are subject to the requirements of the Department of Transportation, through the Federal Motor Carrier Safety Administration, and the Occupational Safety and Health Administration, as well as state and local statutes and regulations that regulate the protection of the health and safety of workers. The failure to comply with these requirements or general industry standards, including keeping adequate records or preventing occupational injuries or exposure, could expose us to civil or criminal liability, enforcement actions, and regulatory fines and penalties that may not be recoverable through our rates and could have a material adverse effect on our business, financial condition, results of operations and cash flows. We intend to work diligently with industry associations and federal and state regulators to comply with these regulations and other new laws. We expect there to be increased costs associated with compliance, and those costs could be significant. If these costs are not recoverable in our customer rates, they could have a negative impact on NW Holdings and NW Naturals operating costs and financial results. RELIANCE ON THIRD PARTIES TO SUPPLY NATURAL GAS, RNG AND ENVIRONMENTAL ATTRIBUTES OR CREDITS RISK. NW Natural relies on third parties to supply the natural gas, RNG and environmental attributes or credits in its NGD segment, and limitations on NW Naturals ability to obtain supplies, or failure to receive expected supplies, could have an adverse impact on NW Holdings or NW Naturals financial results. NW Naturals ability to secure natural gas, RNG and environmental attributes or credits depends upon its ability to purchase and receive delivery of them from third parties. NW Natural, and in some cases its suppliers, does not have control over the availability of natural gas, RNG or environmental attributes or credits, competition for those supplies, disruptions in those supplies, priority allocations on transmission pipelines, markets for those supplies, or pricing and other terms related to such supplies. Additionally, third parties on whom NW Natural relies may fail to deliver supplies for which it has contracted. For example, in October, 2018, a 36-inch pipeline near Prince George, British Columbia owned by Enbridge ruptured, disrupting natural gas flows from Canada into Washington while the ruptured pipeline and an adjacent pipeline were assessed and the ruptured pipeline was repaired. Once repaired, pressurization levels for those pipelines were reduced for a significant period of time for assessment and testing. If NW Natural is unable or limited in its ability to obtain natural gas, RNG or environmental attributes or credits from its current suppliers or new sources, it may not be able to meet customers' gas requirements or regulatory or compliance requirements, and would likely incur costs associated with actions necessary to mitigate service disruptions or regulatory compliance, which could significantly and negatively impact NW Holdings and NW Naturals results of operations. SINGLE TRANSPORTATION PIPELINE RISK. NW Natural relies on a single pipeline company for the transportation of gas to its service territory, a disruption, limitation, or inadequacy of which could adversely impact its ability to meet customers gas requirements, which could significantly and negatively impact NW Holdings and NW Naturals results of operations. NW Naturals distribution system is directly connected to a single interstate pipeline, which is owned and operated by Northwest Pipeline. The pipelines gas flows are bi-directional, transporting gas into the Portland metropolitan market from two directions: (1) the north, which brings supplies from the British Columbia and Alberta supply basins; and (2) the east, which brings supplies from the Alberta and the U.S. Rocky Mountain supply basins. If there is a rupture or inadequate capacity in, or supplies to maintain adequate pressures in, the pipeline, NW Natural may not be able to meet its customers gas requirements and we would likely incur costs associated with actions necessary to mitigate service disruptions, both of which could significantly and negatively impact NW Holdings and NW Naturals results of operations. THIRD PARTY PIPELINE RISK. NW Naturals gas storage business depends on third-party pipelines that connect our storage facilities to interstate pipelines, the failure or unavailability of which could adversely affect NW Holdings or NW Naturals financial condition, results of operations and cash flows. Our gas storage facilities are reliant on the continued operation of a third-party pipeline and other facilities that provide delivery options to and from our storage facilities. Because we do not own all of these pipelines, their operations are not within our control. If the third-party pipeline to which we are connected were to become unavailable for current or future withdrawals or injections of natural gas due to repairs, damage to the infrastructure, lack of capacity or other reasons, our ability to operate efficiently and satisfy our customers needs could be compromised, thereby potentially having an adverse impact on NW Holdings or NW

Naturals financial condition, results of operations and cash flows. WORKFORCE RISK. NW Holdings and NW Naturals businesses are heavily dependent on being able to attract and retain qualified employees and maintain a competitive cost structure with market-based salaries and employee benefits, and workforce disruptions could adversely affect NW Holdings or NW Naturals operations and results. NW Holdings and NW Naturals ability to implement our business strategy and serve our customers is dependent upon our continuing ability to attract and retain diverse, talented professionals and a technically skilled workforce, and being able to transfer the knowledge and expertise of our workforce to new and increasingly diverse employees as our largely older workforce retires. A significant portion of our workforce is currently eligible or will reach retirement eligibility within the next five years, which will require that we attract, train and retain skilled workers to prevent loss of institutional knowledge or skills gaps. We face competition for qualified personnel with specific skillsets. This competition is elevated by the record low unemployment in Oregon and may result in increased pressure on wages or other challenges in recruiting or retaining personnel. Without an appropriately skilled workforce, our ability to provide quality service and meet our regulatory requirements will be challenged and this could negatively impact NW Holdings' and NW Naturals earnings. Additionally, approximately half of NW Natural workers are represented by the OPEIU Local No. 11 AFL-CIO and are covered by a collective bargaining agreement that extends to May 31, 2024. Disputes with the union representing NW Natural employees over terms and conditions of their agreement, or failure to timely and effectively renegotiate the agreement upon its expiration, could result in instability in our labor relationship or other labor disruptions that could impact the timely delivery of gas and other services from our utility and storage facilities, which could strain relationships with customers and state regulators and cause a loss of revenues. The collective bargaining agreements may also limit our flexibility in dealing with NW Naturals workforce, and the ability to change work rules and practices and implement other efficiency-related improvements to successfully compete in todays challenging marketplace, which may negatively affect NW Holdings and NW Naturals financial condition and results of operations. Environmental Risks ENVIRONMENTAL LIABILITY RISK. Certain of NW Naturals, and possibly NW Holdings, properties and facilities may pose environmental risks requiring remediation, the costs of which are difficult to estimate and which could adversely affect NW Holdings and NW Naturals financial condition, results of operations, and cash flows. NW Natural owns, or previously owned, properties that require environmental remediation or other action. NW Holdings or NW Natural may now, or in the future, own other properties that require environmental remediation or other action. NW Natural and NW Holdings accrue all material loss contingencies relating to these properties. A regulatory asset at NW Natural has been recorded for estimated costs pursuant to a deferral order from the OPUC and WUTC. In addition to maintaining regulatory deferrals, NW Natural settled with most of its historical liability insurers for only a portion of the costs it has incurred to date and expects to incur in the future. To the extent amounts NW Natural recovered from insurance are inadequate and it is unable to recover these deferred costs in utility customer rates, NW Natural would be required to reduce its regulatory assets which would result in a charge to earnings in the year in which regulatory assets are reduced. In addition, in Oregon, the OPUC approved the SRRM, which limits recovery of deferred amounts to those amounts which satisfy an annual prudence review and an earnings test that requires NW Natural to contribute additional amounts toward environmental remediation costs above approximately $10 million in years in which NW Natural earns above its authorized ROE. To the extent NW Natural earns more than its authorized ROE in a year, it would be required to cover environmental expenses greater than the $10 million with those earnings that exceed its authorized ROE. The OPUC ordered a review of the SRRM in 2018 or when we obtain greater certainty of environmental costs, whichever occurred first. We submitted information for review in 2018, and believe we could be subject to further review. Similarly, in October 2019, the WUTC authorized an ECRM, which allows for recovery of certain past deferred and future prudently incurred remediation costs allocable to Washington through application of insurance proceeds and collections from customers, subject to an annual prudence determination. These ongoing prudence reviews, or with respect to the SRRM, the earnings test, or the periodic review could reduce the amounts NW Natural is allowed to recover, and could adversely affect NW Holdings or NW Naturals financial condition, results of operations and cash flows. Moreover, we may have disputes with regulators and other parties as to the severity of particular environmental matters, what remediation efforts are appropriate, whether natural resources were damaged, and the portion of the costs or claims NW Natural or NW Holdings should bear. We cannot predict with certainty the amount or timing of future expenditures related to environmental investigations, remediation or other action, the portions of these costs allocable to NW Natural or NW Holdings, or disputes or litigation arising in relation thereto. Environmental liability estimates are based on current remediation technology, industry experience gained at similar sites, an assessment of probable level of responsibility, and the financial condition of other potentially responsible parties. However, it is difficult to estimate such costs due to uncertainties surrounding the course of environmental remediation, the preliminary nature of certain site investigations, natural recovery of the site, unavoidable limitations associated with environmental investigations and remedial technologies, evolving science, and the application of environmental laws that impose joint and several liabilities on all potentially responsible parties. These uncertainties and disputes arising therefrom could lead to further adversarial administrative proceedings or litigation, with associated costs and uncertain outcomes, all of which could adversely affect NW Holdings or NW Naturals financial condition, results of operations and cash flows. ENVIRONMENTAL REGULATION COMPLIANCE RISK. NW Holdings and NW Natural are subject to environmental regulations for our ongoing businesses, compliance with which or failure to comply with, could adversely affect our operations or financial results. NW Holdings and NW Natural are subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local governmental authorities relating to protection of the environment, including those legal requirements that govern discharges of substances into the air and water, the management and disposal of hazardous substances and waste, groundwater quality and availability, plant and wildlife protection, the emitting of greenhouse gases, and other aspects of environmental regulation. For example, our natural gas operations are subject to reporting requirements to a number of governmental authorities including, but not limited to, the Environmental Protection Agency (EPA), the Oregon Department of Environmental Quality (ODEQ), and the Washington State Department of Ecology regarding greenhouse gas emissions. We are also required to reduce emissions of GHGs over time in accordance with the Oregon Climate Protection Program and the Washington Climate Commitment Act. These and other current and future additional environmental regulations at the local, state or national level could result in increased compliance costs or additional operating restrictions, which may or may not be recoverable in customer rates, through insurance or otherwise. If these costs are not recoverable, or if these regulations reduce the desirability, availability, or cost-competitiveness of natural gas, they could have an adverse effect on NW Holdings or NW Naturals operations or financial condition. Furthermore, failure to comply with such laws or regulations could subject us to possible enforcement actions, financial liability or litigation, any of which could adversely affect NW Holdings or NW Naturals financial condition and results of operations. GLOBAL CLIMATE CHANGE RISK. Our businesses may be subject to physical risks associated with climate change, all of which could adversely affect NW Holdings or NW Naturals financial condition, results of operations and cash flows. Climate change may cause physical risks, including an increase in sea level, intensified storms, water scarcity, wildfire susceptibility and intensity and changes in weather conditions, such as changes in precipitation, average temperatures and extreme wind or other extreme weather events or climate conditions. Moreover, a significant portion of the nations gas infrastructure is located in areas susceptible to storm damage that could be aggravated by wetland and barrier island erosion, which could give rise to gas supply interruptions and price spikes. These and other physical changes could result in disruptions to natural gas production and transportation systems potentially increasing the cost of gas and affecting our natural gas businesses ability to procure or transport gas to meet customer demand. These changes could also affect our distribution systems resulting in increased maintenance and capital costs, disruption of service, regulatory actions and lower customer satisfaction. Similar disruptions could occur in NW Holdings water utility businesses. Additionally, to the extent that climate change adversely impacts the economic health or weather conditions of our service territory directly, it could adversely impact customer demand or our customers ability to pay. Such physical risks could have an adverse effect on NW Holdings or NW Naturals financial condition, results of operations, and cash flows. PUBLIC PERCEPTION AND POLICY RISK. Changes in public sentiment or public policy with respect to natural gas, including through local, state or federal laws or legislation or other regulation (including ballot initiatives, executive orders or regulatory codes) or litigation, could adversely affect NW Holdings or NW Naturals financial condition, results of operations and cash flows. There are a number of international, federal, state, and local legislative, legal, regulatory and other initiatives being proposed and adopted in an attempt to measure, control or limit the effects of global warming and climate change, including greenhouse gas (GHG) emissions such as carbon dioxide, nitrous oxide, and methane. Legislation or other forms of public policy or regulation that aim to reduce GHG emissions at the federal, state, or local level have and could continue to take a variety of forms including, but not limited to, GHG emissions limits, reporting requirements, carbon taxes, requirements to purchase carbon credits, building codes, increased efficiency standards, additional charges to fund energy efficiency activities or other regulatory actions, and incentives or mandates to conserve energy, or use renewable energy sources. Federal, state, or local governments may provide tax advantages and other subsidies to support alternative energy sources, withdraw funding from fossil fuel sources, mandate the use of specific fuels or technologies, prohibit the use of natural gas, or promote research into new technologies to reduce the cost and increase the scalability of alternative energy sources. In 2021, the United States rejoined the Paris Agreement on Climate Change, and the United States Presidential administration has issued executive orders aimed at reducing GHG emissions, has declared climate change a national security priority, and continues to consider a wide range of policies, executive orders, rules, legislation and other initiatives to address climate change. For example, the Inflation Reduction Act of 2022 (IRA), was signed into law in August 2022 and includes a number of energy and climate related provisions including funding for the EPA to improve GHG reporting and enforcement, as well as a methane fee applicable to activities associated with gas production and processing facilities, transmission pipelines and certain storage facilities. The U.S. Congress may also pass federal climate change legislation in the future. Additionally, other federal agencies have taken or are expected to take actions related to climate change. For example, in March 2022, the Securities and Exchange Commission (SEC) proposed new rules relating to the disclosure of a range of climate-related matters, PHMSA is expected to prepare regulations and other actions to limit methane emissions and the Commodities Futures Trading Commission (CFTC) has indicated it intends to take actions related to oversight of climate-related financial risks as pertinent to the derivatives and underlying commodities markets. Similarly, other federal agencies and regulations, including but not limited to the Consumer Products Safety Commission, the U.S. Department of Treasury, Federal Acquisitions Regulations, and others have indicated impending actions related to regulation related to climate change. At the state level, the State of Washington has enacted the Climate Commitment Act (CCA), which establishes a comprehensive program that provides an overall limit for GHG emissions from major sources in the state that begins on January 1, 2023 and declines yearly to 95% below 1990 levels by 2050. Similarly, in Oregon, in March 2020, the Oregon Governor issued an executive order (EO) establishing GHG emissions reduction goals and directing state agencies and commissions (including the ODEQ and the OPUC) to facilitate such GHG emission goals. In December 2021, the ODEQ concluded its process and issued final cap and reduce rules for the Climate Protection Program (CPP), which became effective January 1, 2022. The CPP outlines GHG emissions reduction goals of 50% by 2035 and 90% by 2050 from a 1990 baseline. NW Natural is subject to both the CCA and CPP. We expect that there will be additional efforts to address climate change in the 2023 legislative sessions in both Oregon and Washington and we cannot predict whether the legislatures will pass any climate related legislation and the potential impact any such legislation may have on the Company. In addition, the State of Washington has enacted and the State of Oregon and some local jurisdictions are considering building codes that could have the effect of disfavoring or disallowing natural gas in residential or commercial new construction or conversions, including locations within our service territory, such as the recent actions by the City of Eugene to disallow gas in new residential construction beginning with permits issued in mid-2023. A number of local and county jurisdictions are also proposing or passing renewable energy resolutions or other measures in an effort to accelerate renewable energy goals. Such current or future legislation, regulation or other initiatives (including executive orders, ballot initiatives or ordinances) could impose on our natural gas businesses operational requirements or restrictions, additional charges to fund energy efficiency initiatives, or levy a tax based on carbon content. In addition, certain jurisdictions, including San Francisco, Seattle, and New York have enacted measures to ban or discourage the use of new natural gas hookups in residential or other buildings. Other jurisdictions, including several in our service territory, such as the city of Milwaukie, have considered or are currently considering similar restrictions or other measures discouraging the use of natural gas, such as limitations or bans on the use of natural gas in new construction, requiring the conversion of buildings to electric heat, or adopting policies or incentives to encourage the use of electricity in lieu of natural gas. Such restrictions could adversely impact customer growth or usage and could adversely impact our ability to recover costs and maintain reasonable customer rates. In addition, certain cities, local jurisdictions and private parties have initiated lawsuits against companies related to climate change impacts, GHG emissions or climate-related disclosures. While NW Natural has not been subject to such litigation to date, such climate-related claims or actions could be costly to defend and could negatively impact our business, reputation, financial condition, and results of operations. NW Natural believes natural gas has an important role in moving the Pacific Northwest to a low carbon future, and to that end is developing programs and measures to reduce carbon emissions. However, NW Naturals efforts may not happen quickly enough to keep pace with legislation or other regulation, legal changes or public sentiment, or may be more costly or not be as effective as expected. Any of these initiatives, or our unsuccessful response to them, could result in us incurring additional costs to comply with the imposed policies, regulations, restrictions or programs, provide a cost or other competitive advantage to energy sources other than natural gas, reduce demand for natural gas, restrict our customer growth, impose costs or restrictions on end users of natural gas, impact the prices we charge our customers, increase the likelihood of litigation, impose increased costs on us associated with the adoption of new infrastructure and technology to respond to such requirements which may or may not be recoverable in customer rates, and could negatively impact public perception of our services or products that negatively diminishes the value of our brand, all of which could adversely affect NW Holdings or NW Naturals business operations, financial condition and results of operations. Business Continuity and Technology Risks BUSINESS CONTINUITY RISK. NW Holdings and NW Natural may be adversely impacted by local or national disasters, political unrest, terrorist activities, cyber-attacks or data breaches, and other extreme events to which we may not be able to promptly respond, which could adversely affect NW Holdings or NW Naturals operations or financial condition. Local or national disasters, political unrest, terrorist activities, cyber-attacks and data breaches, and other extreme events are a threat to our assets and operations. Companies in critical infrastructure industries may face a heightened risk due to being the target of, and having heightened exposure to, acts of terrorism or sabotage, including physical and security breaches of our physical infrastructure and information technology systems in the form of cyber-attacks or other forms of attacks. These attacks could, among other things, target or impact our technology or mechanical systems that operate our distribution, transmission or storage facilities and result in a disruption in our operations, damage to our system and inability to meet customer requirements. In addition, the threat of terrorist activities could lead to increased economic instability and volatility in the price of RNG, natural gas or other necessary commodities that could affect our operations. Threatened or actual national disasters or terrorist activities may also disrupt capital or bank markets and our ability to raise capital or obtain debt financing, or impact our suppliers or our customers directly. Local disaster or civil unrest could result in disruption of our infrastructure or part of our workforce being unable to operate or maintain our infrastructure or perform other tasks necessary to conduct our business. A slow or inadequate response to events may have an adverse impact on our operations and earnings. We may not be able to maintain sufficient insurance to cover all risks associated with local and national disasters, terrorist activities, cyber-attacks and other attacks or events. Additionally, large scale natural disasters or terrorist attacks could destabilize the insurance industry making the insurance we do have unavailable, which could increase the risk that an event could adversely affect NW Holdings or NW Naturals operations or financial results. RELIANCE ON TECHNOLOGY RISK. NW Holdings and NW Naturals efforts to integrate, consolidate and streamline each of their operations has resulted in increased reliance on technology, the failure of which could adversely affect NW Holdings or NW Naturals financial condition and results of operations. NW Holdings and NW Natural have undertaken a variety of initiatives to integrate, standardize, centralize and streamline operations. These efforts have resulted in greater reliance on technological tools such as, at NW Natural: an enterprise resource planning system, a digital dispatch system, an automated meter reading system, a web-based ordering and tracking system, and other similar

technological tools and initiatives. Our future success will depend, in part, on our ability to anticipate and adapt to technological changes in a cost-effective manner and to offer, on a timely basis, services that meet customer demands and evolving industry standards. New technologies may emerge that could be superior to, or may not be compatible with, some of our existing technologies, and may require us to make significant expenditures to remain competitive. We continue to implement technology to improve our business processes and customer interactions. In addition, our various existing information technology systems require periodic modifications, upgrades and/or replacement. For example, NW Natural has recently implemented upgrades to its SAP system and intends to replace its customer information system in the near future. There are various risks associated with these systems in addition to upgrades and replacements, including hardware and software failure, communications failure, data distortion or destruction, unauthorized access to data, misuse of proprietary or confidential data, unauthorized control through electronic means, programming mistakes and other inadvertent errors or deliberate human acts. In addition, we are dependent on a continuing flow of important components and appropriately skilled individuals to maintain and upgrade our information technology systems. Our suppliers have faced disruptions due to COVID-19 and may face additional production or import delays due to natural disasters, strikes, lock-outs, political unrest, pandemics (including COVID-19) or other such circumstances. Technology services provided by third-parties also could be disrupted due to events and circumstances beyond our control which could adversely impact our business, financial condition and results of operations. Any modifications, upgrades, system maintenance or replacements subject us to inherent costs and risks, including potential disruption of our internal control structure, substantial capital expenditures, additional administrative and operating expenses, retention of sufficiently skilled personnel to implement and operate the new systems, and other risks and costs of delays or difficulties in transitioning to new systems or of integrating new systems into our current systems. In addition, the difficulties with implementing new technology systems may cause disruptions in our business operations and have an adverse effect on our business and operations, if not anticipated and appropriately mitigated. There is also risk that we may not be able to recover all costs associated with projects to improve our technological capabilities, which may adversely affect NW Holdings or NW Naturals financial condition and results of operations.
CYBERSECURITY RISK. NW Holdings and NW Naturals status as an infrastructure services provider coupled with its reliance on technology could result in a security breach which could adversely affect NW Holdings or NW Naturals financial condition and results of operations. Although we take precautions to protect our technology systems and are not aware of any material security breaches to date, there is no guarantee that the procedures we have implemented to protect against unauthorized access to secured data and systems, including our industrial controls and other information technology systems, are adequate to safeguard against all security breaches or other cyberattacks. Additionally, the facilities and systems of clients,

suppliers and third party service providers also could be vulnerable to cyber risks and attacks, and such third party systems may be interconnected to our systems. Therefore, an event caused by cyberattacks or other malicious act at an interconnected third party could impact our business and facilities similarly. As these potential cyber security attacks become more common and sophisticated, we could be required to incur costs to strengthen our systems or maintain insurance coverage against potential losses. Moreover, a variety of regulatory agencies are increasingly focused on cybersecurity risks, and specifically in critical infrastructure sectors. For example, the Transportation Security Administration (TSA) has published multiple security directives and is currently in the process of implementing formal rules mandating cybersecurity actions for critical pipeline owners and operators. Failure to timely and effectively meet the requirements of these directives or other cybersecurity regulations could result in fines or other penalties. We are continuing to evaluate the potential costs of implementation of these directives, and there is no assurance that we will be able to continue to recover in rates costs associated with such compliance. In addition, our businesses could experience breaches of security pertaining to sensitive customer, employee, and vendor information maintained by us in the normal course of business, which could adversely affect our reputation, diminish customer confidence, disrupt operations, materially increase the costs we incur to protect against these risks, and subject us to possible financial liability or increased regulation or litigation. All of these risks could adversely affect NW Holdings or NW Naturals financial condition and results of operations. Financial and Economic Risks HOLDING COMPANY DIVIDEND RISK. As a holding company, NW Holdings depends on its operating subsidiaries, including NW Natural, to meet financial obligations and the ability of NW Holdings to pay dividends on its common stock is dependent on the receipt of dividends and other payments from its subsidiaries, including NW Natural. As a holding company, NW Holdings only significant assets are the stock and membership interests of its operating subsidiaries, which at this time is primarily NW Natural. NW Holdings direct and indirect subsidiaries are separate and distinct legal entities, managed by their own boards of directors, and have no obligation to pay any amounts to their respective shareholders, whether through dividends, loans or other payments. The ability of these companies to pay dividends or make other distributions on their common stock is subject to, among other things: their results of operations, net income, cash flows and financial condition, as well as the success of their business strategies and general economic and competitive conditions; the prior rights of holders of existing and future debt securities and any future preferred stock issued by those companies; and any applicable legal restrictions. In addition, the ability of NW Holdings subsidiaries to pay upstream dividends and make other distributions is subject to applicable state law and regulatory restrictions. Under the OPUC and WUTC regulatory approvals for the holding company formation, if NW Natural ceases to comply with credit and capital structure requirements approved by the OPUC and WUTC, it will not, with limited exceptions, be permitted to pay dividends to NW Holdings. Under the OPUC and WUTC orders authorizing the holding company reorganization, NW Natural may not pay dividends or make distributions to NW Holdings if NW Naturals credit ratings and common equity levels fall below specified ratings and levels. If NW Naturals long-term secured credit ratings are below A- for SP and A3 for Moodys, dividends may be issued so long as NW Naturals common equity is 45% or above. If NW Naturals long-term secured credit ratings are below BBB for SP and Baa2 for Moodys, dividends may be issued so long as NW Naturals common equity is 46% or above. Dividends may not be issued if NW Naturals long-term secured credit ratings fall to BB+ or below for SP or Ba1 or below for Moodys, or if NW Naturals common equity is below 44%. The ratio is measured using common equity and long-term debt excluding imputed debt or debt-like lease obligations, and is determined on a preceding or projected 13-month basis. EMPLOYEE BENEFIT RISK. The cost of providing pension and postretirement healthcare benefits is subject to changes in pension assets and liabilities, changing employee demographics and changing actuarial assumptions, which may have an adverse effect on NW Holdings or NW Naturals financial condition, results of operations and cash flows. Until NW Natural closed the pension plans to new hires, which for non-union employees was in 2006 and for union employees was in 2009, it provided pension plans and postretirement healthcare benefits to eligible full-time utility employees and retirees. Approximately 30% of NW Naturals current utility employees were hired prior to these dates, and therefore remain eligible for these plans. Other businesses we acquire may also have pension plans. The costs to NW Natural, or the other applicable businesses we may acquire, for providing such benefits is subject to change in the market value of the pension assets, changes in employee demographics including longer life expectancies, increases in healthcare costs, current and future legislative changes, and various actuarial calculations and assumptions. The actuarial assumptions used to calculate our future pension and postretirement healthcare expenses may differ materially from actual results due to significant market fluctuations and changing withdrawal rates, wage rates, interest rates and other factors. These differences may result in an adverse impact on the amount of pension contributions, pension expense or other postretirement benefit costs recorded in future periods. Sustained declines in equity markets and reductions in bond rates may have a material adverse effect on the value of the pension fund assets and liabilities. In these circumstances, NW Natural may be required to recognize increased contributions and pension expense earlier than it had planned to the extent that the value of pension assets is less than the total anticipated liability under the plans, which could have a negative impact on NW Holdings and NW Naturals financial condition, results of operations and cash flows. HEDGING RISK. NW Holdings and NW Naturals risk management policies and hedging activities cannot eliminate the risk of commodity price movements and other financial market risks, and hedging activities may expose us to additional liabilities for which rate recovery may be disallowed, which could result in an adverse impact on NW Holdings and NW Naturals operating revenues, costs, derivative assets and liabilities and operating cash flows. NW Naturals gas purchasing requirements expose us to risks of commodity price movements, while NW Holdings and NW Naturals use of debt and equity financing exposes us to interest rate, liquidity and other financial market risks. We attempt to manage these exposures with both financial and physical hedging mechanisms, including NW Naturals gas reserves transactions which are hedges backed by physical gas supplies and interest rate hedging arrangements at NW Holdings and NWN Water. While we have risk management procedures for hedging in place, they may not always work as planned and cannot entirely eliminate the risks associated with hedging. Additionally, our hedging activities may cause us to incur additional expenses to obtain the hedge. We do not hedge our entire interest rate or commodity cost exposure, and the unhedged exposure will vary over time. Gains or losses experienced through NW Naturals hedging activities, including carrying costs, generally flow through NW Naturals PGA mechanism or are recovered in future general rate cases. However, the hedge transactions NW Natural enters into for utility purposes are subject to a prudence review by the OPUC and WUTC, and, if found imprudent, those expenses may be, and have been previously, disallowed, which could have an adverse effect on NW Holdings or NW Naturals financial condition and results of operations. In addition, our actual business requirements and available resources may vary from forecasts, which are used as the basis for hedging decisions and could cause our exposure to be more or less than anticipated. Moreover, if NW Naturals derivative instruments and hedging transactions do not qualify for regulatory deferral and it does not elect hedge accounting treatment under U.S. GAAP, NW Holdings or NW Naturals results of operations and financial condition could be adversely affected. NW Holdings and NW Natural also have credit-related exposure to derivative counterparties. Counterparties owing NW Holdings, NW Natural or their respective subsidiaries money or physical natural gas commodities could breach their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements to meet our normal business requirements. In that event, NW Holdings or NW Naturals financial results could be adversely affected. Additionally, under most of NW Naturals hedging arrangements, any downgrade of its senior unsecured long-term debt credit rating could allow its counterparties to require NW Natural to post cash, a letter of credit or other form of collateral, which would expose NW Natural to additional costs and may trigger significant increases in borrowing from its credit facilities or equity contribution needs from NW Holdings, if the credit rating downgrade is below investment grade. Further, based on current interpretations, each of NW Holdings, NW Natural and NWN Water is not considered a "swap dealer" or "major swap participant" in 2022, so we are exempt from certain requirements under the Dodd-Frank Act. If we are unable to claim this exemption, we could be subject to higher costs for our derivatives activities, and such higher costs could have a negative impact on NW Holdings and NW Naturals operating costs and financial results. GAS PRICE RISK. Higher natural gas commodity prices and volatility in the price of gas may adversely affect NW Naturals NGD business, whereas lower gas price volatility may adversely affect NW Naturals gas storage business, negatively affecting NW Holdings and NW Naturals results of operations and cash flows. The cost of natural gas is affected by a variety of factors, including weather, changes in demand, the level of production and availability of natural gas supplies, transportation constraints, availability and cost of pipeline capacity, federal, state and local energy and environmental policy, regulation and legislation, natural disasters and other catastrophic events, national and worldwide economic and political conditions, and the price and availability of alternative fuels. In 2021 and 2022 there was increased pricing and volatility in the current and forward gas markets. At NW Natural, the cost we pay for natural gas is generally passed through to customers through an annual PGA rate adjustment. If gas prices were to increase significantly and remain higher, it could raise the cost of energy to NW Naturals customers, potentially causing those customers to conserve or switch to alternate sources of energy. Sustained significant price increases could also cause new home builders and commercial developers to select alternative energy sources. Decreases in the volume of gas NW Natural sells could reduce NW Holdings or NW Naturals earnings, and a decline in customers could slow growth in future earnings. Additionally, notwithstanding NW Naturals current rate structure, higher gas costs could result in increased pressure on the OPUC or the WUTC to seek other means to reduce NW Naturals rates, which also could adversely affect NW Holdings and NW Naturals results of operations and cash flows. Temporary gas price increases can also adversely affect NW Holdings and NW Naturals operating cash flows, liquidity and results of operations because a portion (10% or 20%) of any difference between the estimated average PGA gas cost in rates and the actual average gas cost incurred is recognized as current income or expense. Temporary or sustained higher gas prices may also cause NW Natural to experience an increase in short-term debt and temporarily reduce liquidity because it pays suppliers for gas when it is purchased, which can be in advance of when these costs are recovered through rates. Significant increases in the price of gas can also slow collection efforts as customers experience increased difficulty in paying their higher energy bills, leading to higher than normal delinquent accounts receivable resulting in greater expense associated with collection efforts and increased bad debt expense. INABILITY TO ACCESS CAPITAL MARKET RISK. NW Holdings or NW Naturals inability to access capital, or significant increases in the cost of capital, could adversely affect NW Holdings or NW Naturals financial condition and results of operations. NW Holdings and NW Naturals ability to obtain adequate and cost effective short-term and long-term financing depends on maintaining investment grade credit profiles, perceptions of our business in capital markets, and the existence of liquid and stable financial markets. NW Holdings relies on access to equity and bank markets to finance equity contributions to subsidiaries and other business requirements. NW Natural relies on access to capital and bank markets, including commercial paper and bond markets, to finance its operations, construction expenditures and other business requirements, and to refinance maturing debt that cannot be funded entirely by internal cash flows. Disruptions in capital markets, including but not limited to, pandemics, political unrest, inflationary pressures, recessionary pressures, or rising interest rates could adversely affect our ability to access short-term and long-term financing or refinance maturing indebtedness. Our access to funds under committed credit facilities, which are currently provided by a number of banks, is dependent on the ability of the participating banks to meet their funding commitments. Those banks may not be able to meet their funding commitments if they experience shortages of capital and liquidity. Disruptions in the bank or capital financing markets as a result of economic uncertainty, changing or increased regulation of the financial sector, or failure of major financial institutions, or disruptions in credit markets, could adversely affect NW Holdings and NW Naturals access to capital and negatively impact our ability to run our businesses, achieve NW Naturals authorized rate of return, and make strategic investments. Furthermore, recent trends toward investments that are perceived to be green or sustainable could shift capital away from, or increase the cost of capital for, our natural gas business. We believe our business is an important component of a low carbon future and are striving to decarbonize our systems. Nevertheless, perceptions in the financial markets could differ or outpace our decarbonization progress and result in a shift funding away from, or limit or restrict certain forms of funding for, natural gas businesses. NW Natural is currently rated by SP and Moodys and a negative change in its credit ratings, particularly below investment grade, could adversely affect its cost of borrowing and access to sources of liquidity and capital. Such a downgrade could further limit its access to borrowing under available credit lines. Additionally, downgrades in its current credit ratings below investment grade could cause additional delays in NW Natural's ability to access the capital markets while it seeks supplemental state regulatory approval, which could hamper its ability to access credit markets on a timely basis. NW Holdings' credit profile is largely supported by NW Naturals credit ratings and any negative change in NW Naturals credit ratings would likely negatively impact NW Holdings access to sources of liquidity and capital and cost of borrowing. A credit downgrade to NW Natural, or resulting negative impact on NW Holdings, could also require additional support in the form of letters of credit, cash or other forms of collateral and otherwise adversely affect NW Holdings' or NW Naturals financial condition and results of operations. IMPAIRMENT OF LONG-LIVED ASSETS OR GOODWILL RISK . Impairments of the value of long-lived assets or goodwill could have a material effect on NW Holdings or NW Naturals financial condition, or results of operations. NW Holdings and NW Natural review the carrying value of long-lived assets other than goodwill whenever events or changes in circumstances indicate the carrying amount of the assets might not be recoverable. The determination of recoverability is based on the undiscounted net cash flows expected to result from the operation of such assets. Projected cash flows depend on the future operating costs and projected revenues associated with the asset. We review the carrying value of goodwill annually or whenever events or changes in circumstances indicate that such carrying value may not be recoverable. A goodwill impairment analysis begins with a qualitative analysis of events and circumstances. If the qualitative assessment indicates that the carrying value may be at risk, we will perform a quantitative assessment and recognize a goodwill impairment for any amount in which the fair value of a reporting unit exceeds its fair value. NW Holdings' total goodwill was $149.3 million as of December 31, 2022 and $70.6 million as of December 31, 2021. All of our goodwill is related to water and wastewater acquisitions. There have been no impairments recognized for the water and wastewater acquisitions to date. Any impairment charge taken with respect to our long-lived assets or goodwill could be material and could have a material effect on NW Holdings or NW Naturals financial condition and results of operations. CUSTOMER CONSERVATION RISK. Customers conservation efforts may have a negative impact on NW Holdings and NW Naturals revenues. An increasing national focus on energy conservation, including improved building practices and appliance efficiencies may result in increased energy conservation by customers. This can decrease NW Naturals sales of natural gas and adversely affect NW Holdings or NW Naturals results of operations because revenues are collected mostly through volumetric rates, based on the amount of gas sold. In Oregon, NW Natural has a conservation tariff which is designed to recover lost utility margin due to declines in residential and small commercial customers consumption. However, NW Natural does not have a conservation tariff in Washington that provides it this margin protection on sales to customers in that state. Similar conservation risks exist for water utilities. Customers conservation efforts may have a negative impact on NW Holdings' and NW Naturals financial condition, revenues and results of operations. WEATHER RISK. Warmer than average weather may have a negative impact on our revenues and results of operations. We are exposed to weather risk in our natural gas business, primarily at NW Natural. A majority of NW Naturals gas volume is driven by gas sales to space heating residential and small commercial customers during the winter heating season. Current NW Natural rates are based on an assumption of average weather. Warmer than average weather typically results in lower gas sales. Colder weather typically results in higher gas sales. Although the effects of warmer or colder weather on utility margin in Oregon are expected to be mitigated through the operation of NW Naturals weather normalization mechanism, weather variations from normal could adversely affect utility margin because NW Natural may be required to purchase more or less gas at spot rates, which may be higher or lower than the rates assumed in its PGA. Also, a portion of NW Naturals Oregon residential and commercial customers (usually less than 10%) have opted out of the weather normalization mechanism, and approximately 12% of its customers are located in Washington where it does not have a weather normalization mechanism. These effects could have an adverse effect on NW Holdings and NW Naturals financial condition, results of operations and cash flows. Water Business Risks WATER SECTOR BUSINESS. NW Holdings has entered the water sector through the acquisition of a number of water and wastewater companies. Water and wastewater businesses are subject to a number of risks in addition to the risks described above. Although the water businesses are not currently expected to materially contribute to the results of operations of NW Holdings, these businesses are subject to risks, in addition to those described above that could adversely affect their results of operations, including: contamination of water supplies, including water provided to customers with naturally occurring or human-made substances or other hazardous materials; interruptions in water supplies and service, natural disasters and droughts; insufficient water supplies, limitations on or disputes with respect to water rights or supplies, or the inability to secure water rights or supplies at a reasonable cost; disruptions to the wastewater collection and treatment process; reliance on third parties for water supplies and transportation of such water supplies; conservation efforts by customers; regulatory and legal requirements, including environmental, health and safety laws and regulations; operational risks, including customer and employee safety; the outcome of rate cases and other regulatory proceedings; and weather conditions. Significant losses, liabilities or impairments arising from these businesses may adversely affect NW Holdings' financial position or results of operations. INVESTMENT RISK. NW Holdings expectations with respect to the financial results of its investments in water operations are based on various assumptions and beliefs that may not prove accurate, resulting in failures or delays in achieving expected returns or performance. NW Holdings expansion into the water sector is an important component of its growth strategy. Although NW Holdings expects its water and wastewater utility operations will result in various benefits, including expanding customer bases, providing investment opportunities through infrastructure development and enhancing regulatory relationships within the local communities served, NW Holdings may not be able to realize these or other benefits. Achieving the anticipated benefits is subject to a number of uncertainties, including whether the businesses acquired can be operated in the manner intended and whether costs to finance the acquisitions and investments will be consistent with expectations, as well as whether investments in the water sector can reach scale in a reasonable period of time. Events outside of our control, including but not limited to regulatory changes or developments, could adversely affect our ability to realize the anticipated benefits from building NW Holdings water platform. The integration of newly acquired water businesses, particularly over a noncontiguous geographic regions, may be unpredictable, subject to delays or changed circumstances, and such businesses may not perform in accordance with our expectations. In addition, anticipated costs, level of managements attention and internal resources to achieve the integration of or operate the acquired businesses may differ significantly from our current estimates resulting in failures or delays in achieving expected returns or performance. If NW Holdings' expectations regarding the financial results of its investments in water operations prove to be inaccurate, it may adversely affect NW Holdings' financial position or results of operations. Non-Regulated RNG Risks INVESTMENT RISK. NW Holdings expectations with respect to the financial results of its investments in non-regulated RNG investments are based on various assumptions and beliefs that may not prove accurate, resulting in failures or delays in achieving expected returns. NW Holdings expansion into the non-regulated RNG business is an important component of its growth strategy. Although NW Holdings expects this expansion will result in various benefits, including providing cost-effective solutions to decarbonize the utility, commercial, industrial and transportation sectors, NW Holdings may not be able to realize these or other benefits. Achieving the anticipated benefits is subject to a number of uncertainties, including whether the investments can be made at an expected scale, whether the investments can be monetized in the manner intended, and whether costs to finance the investments will be consistent with expectations. Events outside of our control, including but not limited to market or regulatory changes or developments, could adversely affect our ability to realize the anticipated benefits from building NW Holdings non-regulated RNG platform. The establishment and growth of a non-regulated RNG business may be unpredictable, subject to uncertainties or changed circumstances, and such business may not perform in accordance with our expectations. In addition, anticipated costs, level of managements attention and internal resources to achieve the integration of the acquired investments may differ significantly from our current estimates resulting in failures or delays in achieving expected returns or performance. We could additionally experience unsuccessful business models; technological challenges; ineffective scalability or inability to achieve production volumes consistent with our expectations and marketing arrangements; construction delays or cost overruns; disputes with third party business partners; risks related to markets for RNG and its associated attributes (including changes in market regulation, behavior, or prices); the inability to receive expected tax or regulatory treatment; or unexpected operating costs. If NW Holdings' expectations regarding the financial results of its investments in non-regulated RNG prove to be inaccurate, it may adversely affect NW Holdings' financial position or results of operations.

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ITEM 1. BUSINESS OVERVIEW ##TABLE_START ##TABLE_ENDNW Holdings is a holding company headquartered in Portland, Oregon and owns NW Natural, NW Natural Water Company, LLC (NWN Water), NW Natural Renewables Holdings, LLC, a non-regulated subsidiary established to pursue non-regulated renewable natural gas activities, and other businesses and activities. NW Natural is NW Holdings largest subsidiary. NW Natural distributes natural gas to residential, commercial, and industrial customers in Oregon and southwest Washington. NW Natural and its predecessors have supplied gas service to the public since 1859, was incorporated in Oregon in 1910, and began doing business as NW Natural in 1997. NW Natural's natural gas distribution activities are reported in the natural gas distribution (NGD) segment. All other business activities, including certain gas storage activities, water and wastewater businesses, non-regulated renewable natural gas activities and other investments and activities are aggregated and reported as "other" at their respective registrant. NATURAL GAS DISTRIBUTION (NGD) SEGMENT ##TABLE_START ##TABLE_ENDBoth NW Holdings and NW Natural have one reportable segment, the NGD segment, which is operated by NW Natural. NGD provides natural gas service through approximately 795,000 meters in Oregon and southwest Washington. Approximately 88% of customers are located in Oregon and 12% are located in southwest Washington. NW Natural has been allocated an exclusive service territory by the Oregon Public Utility Commission (OPUC) and Washington Utilities and Transportation Commission (WUTC), which includes the major population centers in western Oregon, including the Portland metropolitan area, most of the Willamette Valley, the Coastal area from Astoria to Coos Bay, and portions of Washington along the Columbia River. Major businesses located in NW Natural's service territory include retail, manufacturing, and high-technology industries. Customers The NGD business serves residential, commercial, and industrial customers with no individual customer accounting for more than 10% of NW Natural's or NW Holdings' revenues. On an annual basis, residential and commercial customers typically account for approximately 60% of NGD volumes delivered and approximately 90% of NGD margin. Industrial and other customers largely account for the remaining volumes and margin. The following table presents summary meter information for the NGD segment as of December 31, 2022: ##TABLE_START Number of Meters % of Volumes % of Margin Residential 724,287 38 % 65 % Commercial 69,139 23 % 25 % Industrial 1,071 39 % 7 % Other (1) N/A N/A 3 % Total 794,497 100 % 100 % ##TABLE_END(1) NGD margin is also affected by other items, including miscellaneous revenues, gains or losses from NW Natural's gas cost incentive sharing mechanism, other margin adjustments, and other regulated services. Generally, residential and commercial customers purchase both their natural gas commodity (gas sales) and natural gas delivery services (transportation services) from the NGD business. Industrial customers also purchase transportation services, but may buy the gas commodity either from NW Natural or directly from a third-party gas marketer or supplier. Gas commodity cost is primarily a pass-through cost to customers; therefore, profit margins are not significantly affected by an industrial customer's decision to purchase gas from NW Natural or from third parties. Industrial and large commercial customers may also select between firm and interruptible service levels, with firm services generally providing higher profit margins compared to interruptible services. To help manage gas supplies, industrial tariffs are designed to provide some certainty regarding industrial customers' volumes by requiring an annual service election, special rates or possible restrictions for changes between elections, and in some cases, a minimum or maximum volume requirement before changing options. We estimate natural gas was in approximately 63% of single-family residential homes in NW Natural's service territory in 2022. Customer growth in our region comes mainly from the following sources: single-family housing, both new construction and conversions; multifamily housing new construction; and commercial buildings, both new construction and conversions. Single-family new construction has consistently been our largest source of growth. Continued customer growth is closely tied to consumer preference for natural gas, the comparative price of natural gas to electricity and fuel oil, regulations and building codes permitting the use of natural gas in new construction and conversions, and the economic health of our service territory. Competitive Conditions In its service areas, the NGD business has no direct competition from other natural gas distributors. However, it competes with other forms of energy in each customer class. This competition among energy suppliers is based on price, efficiency, reliability, performance, preference, market conditions, building codes, technology, federal, state, and local energy policy, and environmental impacts. For residential and small to mid-size commercial customers, the NGD business competes primarily with providers of electricity, fuel oil, and propane. In the industrial and large commercial markets, the NGD business competes with all forms of energy, including competition from wholesale natural gas marketers. In addition, large industrial customers could bypass NW Natural's natural gas distribution system by installing their own direct pipeline connection to the interstate pipeline system. NW Natural has designed custom transportation service agreements with several large industrial customers to provide transportation service rates that are competitive with the customers costs of installing their own pipeline. Seasonality of Business The NGD business is seasonal in nature due to higher gas usage by residential and commercial customers during the cold winter heating months. Other categories of customers experience similar seasonality in their usage but to a lesser extent. Regulation and Rates The NGD business is subject to regulation by the OPUC and WUTC. These regulatory agencies authorize rates and allow recovery mechanisms to provide the opportunity to recover prudently incurred capital and operating costs from customers, while also earning a reasonable return on investment for investors. In addition, the OPUC and WUTC also regulate the system of accounts and issuance of securities by NW Natural. NW Natural files general rate cases and rate tariff requests periodically with the OPUC and WUTC to establish approved rates, an authorized return on equity (ROE), an overall rate of return (ROR) on rate base, an authorized capital structure, and other revenue/cost deferral and recovery mechanisms. NW Natural is also regulated by the Federal Energy Regulatory Commission (FERC). Under NW Natural's Mist interstate storage certificate with FERC, NW Natural is required to file either a petition for rate approval or a cost and revenue study every five years to change or justify maintaining the existing rates for the interstate storage service. For further discussion on our most recent general rate cases, see Part II, Item 7, "Results of OperationsRegulatory Matters Regulation and Rates ." Gas Supply NW Natural strives to secure sufficient, reliable supplies of natural gas to meet the needs of customers at the lowest reasonable cost, while maintaining price stability, managing gas purchase costs prudently and supporting our core value of environmental stewardship. This is accomplished through a comprehensive strategy focused on the following items: Reliability - ensuring gas resource portfolios are sufficient to satisfy customer requirements under extreme cold weather conditions; Diverse Supply - providing diversity of supply sources; Diverse Contracts - maintaining a variety of contract durations, types, and counterparties; Cost Management and Recovery - employing prudent gas cost management strategies; and Environmental Stewardship - striving to reduce the carbon content and environmental impacts of the energy we deliver. Reliability To support system reliability, the NGD business has developed a risk-based methodology in which it uses a planning standard to serve the highest firm sales demand day in any year with 99% certainty. The projected maximum design day firm NGD customer sales is approximately 10 million therms. Of this total, the NGD business is currently capable of meeting approximately 50% of the requirements with gas from storage located within or adjacent to its service territory, while the remaining supply requirements would come from gas purchases under firm gas purchase contracts and recall agreements. NW Natural segments transportation capacity, which is a natural gas transportation mechanism under which a shipper can leverage its firm pipeline transportation capacity by separating it into multiple segments with alternate delivery routes. The reliability of service on these alternate routes will vary depending on the constraints of the pipeline system. For those segments with acceptable reliability, segmentation provides a shipper with increased flexibility and potential cost savings compared to traditional pipeline service. The NGD business relies on segmentation of firm pipeline transportation capacity that flows from Stanfield, Oregon to various points south of Molalla, Oregon. We believe gas supplies would be sufficient to meet existing NGD firm customer demand in the event of maximum design day weather conditions. The following table shows the sources of supply projected to be used to satisfy the design day sales for the 2022-23 winter heating season: ##TABLE_START Therms in millions Therms Percent Sources of NGD supply: Firm supply purchases 3.4 34 % Mist underground storage (NGD only) 3.1 30 % Company-owned LNG storage 1.9 19 % Off-system storage contract 0.5 5 % Pipeline segmentation capacity 0.6 6 % Recall agreements 0.4 4 % Peak day citygate deliveries 0.2 2 % Total 10.1 100 % ##TABLE_ENDThe OPUC and WUTC have Integrated Resource Planning (IRP) processes in which utilities define different future scenarios and corresponding resource and compliance strategies in an effort to evaluate supply and demand resource and compliance requirements, consider uncertainties in the planning process and the need for flexibility to respond to changes, and establish a plan for providing reliable service while meeting carbon compliance obligations within frameworks that emphasize least cost and risk. NW Natural generally files a full IRP biennially for Oregon and Washington with the OPUC and the WUTC, respectively, and files updates in Oregon between filings. The OPUC acknowledges NW Natural's action plan, whereas the WUTC provides notice that the IRP has met the requirements of the Washington Administrative Code. OPUC acknowledgment of the IRP does not constitute ratemaking approval of any specific resource acquisition strategy or expenditure. For additional information see Part II, Item 7, "Results of Operations Regulatory Matters ." Diversity of Supply Sources NW Natural purchases gas supplies primarily from the Alberta and British Columbia provinces of Canada and multiple receipt points in the U.S. Rocky Mountains to protect against regional supply disruptions and to take advantage of price differentials. For 2022, 60% of gas supply came from Canada, with the balance primarily coming from the U.S. Rocky Mountain region. The extraction of shale gas has increased the availability of gas supplies throughout North America. We believe gas supplies available in the western United States and Canada are adequate to serve NGD customer requirements for the foreseeable future. NW

Natural continues to evaluate the long-term supply mix based on projections of gas production and pricing in the U.S. Rocky Mountain region as well as other regions in North America. NW Natural supplements firm gas supply purchases with gas withdrawals from gas storage facilities, including underground reservoirs and LNG storage facilities. Storage facilities are generally injected with natural gas during the off-peak months in the spring and summer, and the gas is withdrawn for use during peak demand months in the winter. The following table presents the storage facilities available for NGD business supply: ##TABLE_START Maximum Daily Deliverability (therms in millions) Designed Storage Capacity (Bcf) Gas Storage Facilities Owned Facility Mist, Oregon (Mist Facility) (1) 3.1 11.7 Mist, Oregon (North Mist Facility) (2) 1.3 4.1 Contracted Facility Jackson Prairie, Washington (3) 0.5 1.1 LNG Facilities Owned Facilities Newport, Oregon 0.6 1.0 Portland, Oregon 1.3 0.6 Total 6.8 18.5 ##TABLE_END(1) The Mist gas storage facility has a total maximum daily deliverability of 5.1 million therms and a total designed storage capacity of about 17.5 Bcf, of which 3.1 million therms of daily deliverability and 11.7 Bcf of storage capacity are reserved for NGD business customers. (2) The North Mist facility is contracted to exclusively serve Portland General Electric, a local electric utility, and may not be used to serve other NGD customers. See " North Mist Gas Storage Facility " below for more information. (3) The storage facility is located near Chehalis, Washington and is contracted from Northwest Pipeline, a subsidiary of The Williams Companies. The Mist facility serves NGD segment customers and is also used for non-NGD purposes, primarily for contracts with gas storage customers, including utilities and third-party marketers. Under regulatory agreements with the OPUC and WUTC, gas storage at Mist can be developed in advance of NGD customer needs but is subject to recall when needed to serve such customers as their demand increases. When storage capacity is recalled for NGD purposes it becomes part of the NGD segment. In 2022, the NGD business did not recall additional deliverability or associated storage capacity to serve customer needs. The North Mist facility is contracted for the exclusive use of Portland General Electric, a local electric utility, and may not be used to serve other NGD customers. See " North Mist Gas Storage Facility " below. Diverse Contract Durations and Types NW Natural has a diverse portfolio of short-, medium-, and long-term firm gas supply contracts and a variety of contract types including firm and interruptible supplies as well as supplemental supplies from gas storage facilities. The portfolio of firm gas supply contracts typically includes the following gas purchase contracts: year-round and winter-only baseload supplies; seasonal supply with an option to call on additional daily supplies during the winter heating season; and daily or monthly spot purchases. During 2022, a total of 886 million therms were purchased under contracts with durations as follows: ##TABLE_START Contract Duration (primary term) Percent of Purchases Long-term (one year or longer) 29 % Short-term (more than one month, less than one year) 34 Spot (one month or less) 37 Total 100 % ##TABLE_ENDGas supply contracts are renewed or replaced as they expire. During 2022, there was one supplier that provided 10% of the NGD business gas supply requirements. No other individual supplier provided 10% or more of the NGD business gas supply requirements. Gas Cost Management The cost of gas sold to NGD customers primarily consists of the following items, which are included in annual Purchased Gas Adjustment (PGA) rates: gas purchases from suppliers; charges from pipeline companies to transport gas to our distribution system; gas storage costs; gas reserves contracts; gas commodity derivative contracts; and renewable natural gas and its attributes, including renewable thermal certificates (RTCs). We expect that costs to comply with Oregon's Climate Protection Program (CPP) and Washington's Climate Commitment Act (CCA) programs will be included in the cost of gas. The NGD business employs a number of strategies to mitigate the cost of gas sold to customers. The primary strategies for managing gas commodity price risk include: negotiating fixed prices directly with gas suppliers; negotiating financial derivative contracts that: (1) effectively convert floating index prices in physical gas supply contracts to fixed prices (referred to as commodity price swaps); or (2) effectively set a ceiling or floor price, or both, on floating index priced physical supply contracts (referred to as commodity price options such as calls, puts, and collars); buying physical gas supplies at a set price and injecting the gas into storage for price stability and to minimize pipeline capacity demand costs; and investing in gas reserves for longer term price stability. See Note 13 for additional information about our gas reserves. NW Natural also contracts with an independent energy marketing company to capture opportunities regarding storage and pipeline capacity when those assets are not serving the needs of NGD business customers. Asset management activities provide opportunities for cost of gas savings for customers and incremental revenues for NW Natural through regulatory incentive-sharing mechanisms. These activities, net of the amount shared, are included in other for segment reporting purposes. Gas Cost Recovery Mechanisms for gas cost recovery are designed to be fair and reasonable, with an appropriate balance between the interests of customers and NW Natural. In general, natural gas distribution rates are designed to recover the costs of, but not to earn a return on, the gas commodity sold. Risks associated with gas cost recovery are minimized by resetting customer rates annually through the PGA and aligning customer and shareholder interests through the use of sharing, weather normalization, and conservation mechanisms in Oregon. See Part II, Item 7, "Results of Operations Regulatory Matters " and "Results of OperationsBusiness SegmentsNatural Gas Distribution Operations Cost of Gas " . Environmental Stewardship Part of our gas supply strategy is working to reduce the carbon content and the environmental impacts of the energy we deliver. To that end, NW Natural developed and implemented an emissions screening tool that uses Environmental Protection Agency (EPA) data to calculate the relative emissions intensity of gas producer operations and prioritize purchases from lower emitting producers. In 2019, we began using this emissions intensity screening tool alongside other purchasing criteria such as price, credit worthiness and geographic diversity. The result has been a cost-neutral way to reduce carbon emissions associated with our natural gas supply. NW Natural is focused on taking steps to lower its emissions on behalf of customers by purchasing environmental attributes that are generated by the production of renewable natural gas (RNG). Under Oregon Senate Bill 98, NW Natural can purchase or invest in RNG facilities, which generate these environmental attributes known as Renewable Thermal Certificates (RTCs). The RTCs work like renewable energy certificates, or RECs, used in electricity markets. RTCs are verified and certified by the Midwest Renewable Energy Tracking System (M-RETS). The M-RETS Renewable Thermal Tracking System issues one RTC for every dekatherm of RNG injected into the gas system. NW Natural enters into contracts for the purchase of RNG and RTCs either through periodic request for proposals or through formal offerings or informal requests. See Part II, Item 7, "Results of Operations Regulatory Matters ". In addition to purchases of RNG, NW Natural is subject to the carbon-reduction requirements of the Oregon CPP and the Washington CCA programs. NW Natural has modeled pathways to compliance with the CPP and CCA in its most recent IRP, which are currently under review by the OPUC and WUTC. While costs associated with each possible compliance pathway differ, we intend to pursue recovery of the costs associated with these programs in rates. Transportation of Gas Supplies NW Natural's gas distribution system is reliant on a single, bi-directional interstate transmission pipeline to bring gas supplies into the natural gas distribution system. Although dependent on a single pipeline, the pipeline s gas flows into the Portland metropolitan market from two directions: (1) the north, which brings supplies from the British Columbia and Alberta supply basins; and (2) the east, which brings supplies from Alberta as well as the U.S. Rocky Mountain supply basins. NW Natural incurs monthly demand charges related to firm pipeline transportation contracts. These contracts have expiration dates ranging from 2023 to 2061. The largest pipeline agreements are with Northwest Pipeline. NW Natural actively works with Northwest Pipeline and others to renew contracts in advance of expiration to ensure gas transportation capacity is sufficient to meet customer needs. Rates for interstate pipeline transportation services are established by FERC within the U.S. and by Canadian authorities for services on Canadian pipelines. Gas Distribution Safety and the protection of employees, customers, and our communities are, and will remain, top priorities. NW Natural constructs, operates, and maintains its pipeline distribution system and storage operations with the goal of ensuring natural gas is delivered and stored safely, reliably, and efficiently. NW Natural has one of the most modern distribution systems in the country with no identified cast iron pipe or bare steel main. Since the 1980s, NW Natural has taken a proactive approach to replacement programs and partnered with the OPUC and WUTC on progressive regulation to further safety and reliability efforts for the distribution system. In the past, NW Natural had a cost recovery program in Oregon that encompassed programs for cast iron replacement, bare steel replacement, transmission integrity management, and distribution integrity management programs as appropriate. Natural gas distribution businesses are likely to be subject to greater federal and state regulation in the future. Additional operating and safety regulations from the U.S. Department of Transportations Pipeline and Hazardous Materials Safety Administration (PHMSA) are currently under development. In 2016, PHMSA issued a notice of proposed rulemaking titled the "Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments." In 2019, PHMSA issued the first of three portions of the rulemaking which went into effect on July 1, 2020 and includes up to a 15-year timeline for compliance. The second portion of the rule known as the gas gathering rule was issued in late 2021, and final rulemaking titled "The Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments" was issued in August 2022. A Gas Pipeline Leak Detection rule is expected to be issued in 2023. NW Natural intends to continue to work diligently with industry associations as well as federal and state regulators to support the safety of the system and compliance with new laws and regulations. We expect the costs associated with compliance with federal, state, and local laws and regulations to be recovered in rates. North Mist Gas Storage Facility In May 2019, NW Natural completed an expansion of its existing gas storage facility near Mist, Oregon. The North Mist facility provides long-term, no-notice underground gas storage service and is dedicated solely to Portland General Electric (PGE) under a 30-year contract with options to extend up to an additional 50 years upon mutual agreement of the parties. PGE uses the facility to fuel its gas-fired electric power generation facilities, which backs up PGE's variable load of renewable energy on the electric grid. North Mist includes a reservoir providing 4.1 Bcf of available storage, an additional compressor station with a contractual capacity of 120,000 dekatherms of gas deliverability per day, no-notice service that can be drawn on rapidly, and a 13-mile pipeline to connect to PGE's Port Westward gas plants in Clatskanie, Oregon. Upon placement into service in May 2019, the facility was included in rate base under an established tariff schedule with revenues recognized consistent with the schedule. Billing rates are updated annually to the forecasted depreciable asset level and forecasted operating expenses. While there are additional expansion opportunities in the Mist storage field, any expansion would be based on market demand, cost effectiveness, available financing, receipt of future permits, and other rights. OTHER ##TABLE_START ##TABLE_ENDCertain businesses and activities of NW Holdings and NW Natural are aggregated and reported as other for segment reporting purposes. NW Natural The following businesses and activities are aggregated and reported as other under NW Natural, a wholly-owned subsidiary of NW Holdings: 5.8 Bcf of the Mist gas storage facility contracted to other utilities and third-party marketers; natural gas asset management activities; and appliance retail center operations. Mist Gas Storage The Mist gas storage facility began operations in 1989. It is a 17.5 Bcf facility with 11.7 Bcf used to provide gas storage for the NGD business. The remaining 5.8 Bcf of the facility is contracted with other utilities and third-party marketers with these results reported in other. In 2022, NW Natural utilized 0.5 Bcf of increased storage capacity realized through reservoir expansion during more than 15 years of delta pressure operations. This change increased the working gas capacity from 17.0 Bcf in 2021 to 17.5 Bcf in 2022. The overall facility consists of seven depleted natural gas reservoirs, 22 injection and withdrawal wells, a compressor station, dehydration and control equipment, gathering lines, and other related facilities. The capacity at Mist serving other utilities and third-party marketers provides multi-cycle gas storage services to customers in the interstate and intrastate markets. The interstate storage services are offered under a limited jurisdiction blanket certificate issued by FERC. Under NW Natural's interstate storage certificate with FERC, NW Natural is required to file either a petition for rate approval or a cost and revenue study every five years to change or justify maintaining the existing rates for the interstate storage service. Intrastate firm storage services in Oregon are offered under an OPUC-approved rate schedule as an optional service to certain eligible customers. Gas storage revenues from the 5.8 Bcf are derived primarily from firm service customers who provide energy-related services, including natural gas distribution, electric generation, and energy marketing. The Mist facility benefits from limited competition as there are few storage facilities in the Pacific Northwest region. Therefore, NW Natural is able to acquire high-value, multi-year contracts. Asset Management Activities NW Natural contracts with an independent energy marketing company to provide asset management services, primarily through the use of natural gas commodity exchange agreements and natural gas pipeline capacity release transactions. The results of these activities are included in other, except for the asset management revenues allocated to NGD business customers pursuant to regulatory agreements, which are reported in the NGD segment. NW Holdings These include the following businesses and activities aggregated under NW Holdings: NW Natural Water Company, LLC (NWN Water) and its water and wastewater utility operations; NWN Water's equity investment in Avion Water Company, Inc.; NW Natural Renewables Holdings, LLC and its non-regulated renewable natural gas activities; a minority interest in the Kelso-Beaver Pipeline held by our wholly-owned subsidiary NNG Financial Corporation (NNG Financial); and holding company and corporate activities, including business development activities, as well as adjustments made in consolidation. NW Natural Water NWN Water currently serves an estimated 155,000 people through approximately 62,500 water and wastewater connections across five states. NWN Water continues to grow though customer additions within or near its service territories, and continues to pursue acquisitions. For recently acquired water utilities, see further discussion about the status of water general rate cases in Part II, Item 7, "Results of OperationsRegulatory Matters Water General Rate Cases ." The water and wastewater utilities primarily serve residential and commercial customers. Water distribution operations are seasonal in nature with peak demand during warmer summer months, while wastewater is less seasonally affected. Entities generally operate in exclusive service territories with no direct competitors. Water distribution customer rates are regulated by state utility commissions while the wastewater businesses we own consist of some state regulated systems and some systems that are not rate regulated by utility commissions. NW Natural Renewables NW Natural Renewables is a newly formed non-regulated subsidiary of NW Natural Holdings established to invest in renewable energy through the production and supply of

lower-carbon fuels. NW Natural Renewables' first project is with a subsidiary of EDL, a global producer of sustainable distributed energy. In September 2021, a subsidiary of NW Natural Renewables and a subsidiary of EDL executed agreements, whereby the subsidiary of NW Natural Renewables committed $50 million toward the development of two production facilities that are designed to convert landfill waste gases to RNG and connect gas production to existing regional pipeline networks. Testing and commissioning of the production facilities is expected to occur in the spring of 2023. Alongside these development agreements, a subsidiary of NW Natural Renewables and a subsidiary of EDL executed agreements designed to secure a 20-year supply of RNG produced from the facilities for NW Natural Renewables. In 2022, NW Natural Renewables executed a four-year off-take agreement with a counterparty for the near-term RNG production. NW Natural Renewables is currently in discussions with other counterparties to contract the remaining RNG production under long-term contracts. ENVIRONMENTAL MATTERS ##TABLE_START ##TABLE_ENDProperties and Facilities NW Natural owns, or previously owned, properties and facilities that are currently being investigated that may require environmental remediation and are subject to federal, state, and local laws and regulations related to environmental matters. These laws and regulations may require expenditures over a long time frame to address certain environmental impacts. Estimates of liabilities for environmental costs are difficult to determine with precision because of the various factors that can affect their ultimate disposition. These factors include, but are not limited to, the following: the complexity of the site; changes in environmental laws and regulations at the federal, state, and local levels; the number of regulatory agencies or other parties involved; new technology that renders previous technology obsolete, or experience with existing technology that proves ineffective; the level of remediation required; variations between the estimated and actual period of time that must be dedicated to respond to an environmentally-contaminated site; and the application of environmental laws that impose joint and several liabilities on all potentially responsible parties. NW Natural has received recovery of a portion of such environmental costs through insurance proceeds, seeks the remainder of such costs through customer rates, and believes recovery of these costs is probable. In both Oregon and Washington, NW Natural has mechanisms to recover expenses. Oregon recoveries are subject to an earnings test. See Part II, Item 7, "Results of OperationsRegulatory MattersRate Mechanisms Environmental Cost Deferral and Recovery ", and Note 2 and Note 17 of the Consolidated Financial Statements in Item 8 of this report for more information. Greenhouse Gas Matters For information concerning greenhouse gas matters, see Part II, Item 7, Results of OperationsEnvironmental Regulation and Legislation Matters. HUMAN CAPITAL ##TABLE_START ##TABLE_ENDOur core values of integrity, safety, caring, service ethic, and environmental stewardship guide how we engage with customers, stakeholders, shareholders, and communities. We actively work to foster these values in our employee culture and to nurture an inclusive and equitable environment that provides opportunities, prioritizes health and safety, encourages respect and trust, and supports growth and learning. We aim to recruit and retain employees who share our core values and reect our communities. Employees At December 31, 2022, our workforce consisted of the following: ##TABLE_START NW Natural: Unionized employees (1) 575 Non-unionized employees 574 Total NW Natural 1,149 Other Entities: Water and wastewater company employees 105 Other 4 Total other entities 109 Total Employees 1,258 ##TABLE_END(1) Members of the Office and Professional Employees International Union (OPEIU) Local No. 11, AFL-CIO. NW Natural's labor agreement with members of OPEIU covers wages, benefits, and working conditions. In November 2019, NW Natural's unionized employees ratified a collective bargaining agreement that took effect on December 1, 2019 and extends to May 31, 2024, and thereafter from year to year unless either party serves notice of its intent to negotiate modifications to the collective bargaining agreement. During calendar year 2022, NW Natural did not incur any work stoppages (strikes or lockouts), and therefore, experienced zero idle days for the year. Certain subsidiaries may receive services from employees of other subsidiaries. When such services involve regulated entities, those entities receiving services reimburse the entity providing services pursuant to shared services agreements, as applicable. Safety Safety is one of our greatest responsibilities to employees. In managing the business, we strive to foster a safety culture focused on prevention, open communication, collaboration, and a strong service and safety ethic. We believe employee safety is critical to our success. A portion of executives compensation is tied to achieving our safety metrics, and our Board of Directors regularly reviews company safety metrics. NW Naturals health and safety policies and procedures are designed to comply with all applicable regulations, but we also work to go beyond compliance by striving to incorporate industry best practices and benchmarking. As part of our commitment to employee health and safety, we maintain regular training programs, emergency preparedness procedures, and specic training and procedures to identify hazards and handle high-risk emergency situations. Employees complete classroom instruction and hands-on, scenario-based training at our training facility in Oregon that allows employees to experience realistic situations in a controlled environment. We also host natural gas safety training events for rst responders, which are designed to prepare those first responders and NW Natural field employees to deliver an integrated, seamless response in the event of an emergency that involves or affects the natural gas system. We navigated, and continue to navigate, the COVID-19 pandemic to help keep people safe. We also implemented a new learning management system that went live in early 2021 and provides more efficiency and flexibility in how we train. Employee Benefits and Support To attract employees and meet the needs of our workforce, NW Natural strives to offer competitive compensation and benefits packages to employees. The benefits package options vary depending on type of employee and date of hire. NW Natural continuously looks for ways to support employees work-life balance and well-being and this is reflected in physical, mental and financial wellness programs to meet the needs of our employees and help them care for their families. Benefits available to employees during 2022 included, among others:

healthcare and other insurance coverages, wellness resources, retirement and savings plans, paid time off programs, and flexible and hybrid work schedules, where possible, employee resource groups, and culture and community-focused resources and opportunities, and employee recognition programs and discounts. Talent Attraction and Development In order to implement our business strategy and serve our customers, we depend upon our continuing ability to attract and retain diverse, talented professionals and a technically skilled workforce, and being able to transfer the knowledge and expertise of our workforce to new and increasingly diverse employees as our largely older workforce retires. A significant portion of our workforce is currently eligible or will reach retirement eligibility within the next five years, and therefore, we are focused on efforts to attract, train, and retain appropriately qualified and skilled workers to prevent loss of institutional knowledge or skills gaps. NW Natural seeks to provide its employees with growth and development opportunities through programs designed to build skills and relationships. These programs currently include: (i) a culturally relevant mentoring program that creates opportunities for career growth by building relationships; (ii) a tuition assistance program for qualified educational pursuits; (iii) an internal class that provides participants with a big-picture understanding of the industry and company operations, equipping them to see how they contribute to NW Naturals success and identify opportunities for career growth; (iv) internal and external continuing educational courses relevant to areas of expertise; and (v) ongoing management and leadership training programs. We regularly monitor employee engagement and satisfaction through a variety of tools, including our annual engagement survey that is designed to enable company leaders to gather valuable feedback and guidance from employees. Diversity, Equity and Inclusion We have a longstanding commitment to creating a diverse and inclusive culture that reflects and supports the communities we serve, and believe a diverse, equitable, and inclusive workforce at all levels contributes to long-term success. Our efforts in recruiting, promoting, and retaining diverse talent, building inclusive teams, and creating a culture that embraces differences are at the core of our workforce strategy. To attract diverse candidates, we work with community partners to help promote awareness of job opportunities within diverse communities. We have employee-led groups that develop programs and activities that build awareness around issues important to their co-workers, families, customers, and our community. Groups include the Diversity, Equity Inclusion Council, Women's Network, African American, Rainbow Alliance (LGBTQ+), Veterans, Somos Unidos (Latinx), Asian American, and Neurodiversity employee resource groups, Wellness Advisory Committee, and Sustainability and Equity Engagement Team. We also continue to emphasize diversity, equity and inclusion values through employee training and education, including expanded diversity training as part of new hire onboarding and other diversity, equity, and inclusion education that occurs throughout the year. An area of focus going forward is to understand and increase awareness of internal systems and structures that could limit representation and equity for underrepresented employees. To that end, we are working toward revising and refocusing new manager and new hire training to include implicit bias, diversity, equity and inclusion, and anti-racism education. INFORMATION ABOUT OUR EXECUTIVE OFFICERS ##TABLE_START ##TABLE_ENDFor information concerning executive officers, see Part III, Item 10. AVAILABLE INFORMATION ##TABLE_START ##TABLE_ENDNW Holdings and NW Natural file annual, quarterly and current reports and other information with the Securities and Exchange Commission (SEC). The SEC maintains an Internet site where reports, proxy statements, and other information filed can be read, copied, and requested online at its website (www.sec.gov). In addition, we make available, free of charge, on our website (www.nwnaturalholdings.com), our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) and proxy materials filed under Section 14 of the Securities Exchange Act of 1934, as amended (Exchange Act), as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. We intend to use our website as a means of disclosing material non-public information and for complying with our disclosure obligations under Regulation FD. Accordingly, investors should monitor our website, in addition to following our press releases, SEC filings and public conference calls and webcasts. We have included our website address as an inactive textual reference only. Information contained on our website is not incorporated by reference into this annual report on Form 10-K. NW Holdings and NW Natural have adopted a Code of Ethics for all employees, officers, and directors that is available on our website. We intend to disclose revisions and amendments to, and any waivers from, the Code of Ethics for officers and directors on our website. Our Corporate Governance Standards, Director Independence Standards, charters of each of the committees of the Board of Directors, and additional information about NW Holdings and NW Natural are also available at the website. Copies of these documents may be requested, at no cost, by writing or calling Shareholder Services, Northwest Natural Holding Company, 250 S.W. Taylor Street, Portland, Oregon 97204, telephone 503-220-2402. ITEM 1A. RISK FACTORS NW Holdings and NW Naturals business and financial results are subject to a number of risks and uncertainties, many of which are not within our control, which could adversely affect our business, financial condition, and results of operations. Additional risks and uncertainties that are not currently known to us or that are not currently believed by us to be material may also harm our businesses, financial condition, and results of operations. When considering any investment in NW Holdings or NW Naturals securities, investors should carefully consider the following information, as well as information contained in the caption "Forward-Looking Statements", Item 7A, and our other documents filed with the SEC. This list is not exhaustive and the order of presentation does not reflect managements determination of priority or likelihood. Additionally, our listing of risk factors that primarily affects one of our businesses does not mean that such risk factor is inapplicable to our other businesses. Legal, Regulatory and Legislative Risks REGULATORY RISK. Regulation of NW Holdings and NW Naturals regulated businesses, including changes in the regulatory environment, failure of regulatory authorities to approve rates which provide for timely recovery of costs and an adequate return on invested capital, or an unfavorable outcome in regulatory proceedings may adversely impact NW Holdings and NW Naturals financial condition and results of operations. The OPUC and WUTC have general regulatory authority over NW Naturals gas business in Oregon and Washington. NW Holdings regulated water utility businesses are generally regulated by the public utility commission in the state in which a water business is located. These public utility commissions have broad regulatory authority, including: the rates charged to customers; authorized rates of return on rate base, including ROE; the amounts and types of securities that may be issued by our regulated utility companies, like NW Natural; services our regulated utility companies provide and the manner in which they provide them; the nature of investments our utility companies make; deferral and recovery of various expenses, including, but not limited to, pipeline replacement, environmental remediation costs, capital and information technology investments, commodity hedging expense, and certain employee benefit expenses such as pension costs; transactions with affiliated interests; regulatory adjustment mechanisms such as weather adjustment mechanisms, and other matters. The OPUC also regulates actions investors may take with respect to our utility companies, NW Natural and NW Holdings. Similarly, FERC has regulatory authority over NW Naturals interstate storage services. Expansion of our businesses generally results in regulation by other regulatory authorities. For example, certain of NW Holdings water companies are regulated in Idaho, Texas and Arizona. The costs that are deemed recoverable in rates and prices regulators allow us to charge for regulated utility service, and the maximum FERC-approved rates FERC authorizes us to charge for interstate storage and related transportation services, are the most significant factors affecting both NW Naturals and NW Holdings financial position, results of operations and liquidity. State utility regulators have the authority to disallow recovery of costs they find imprudently incurred or otherwise disallowed, and rates that regulators allow may be insufficient for recovery of costs we incur. We expect to continue to make expenditures to expand, improve and safely operate our gas and water utility distribution and gas storage systems, and to work toward decarbonizing our gas systems. Regulators can deny recovery of those costs. Furthermore, while each applicable state regulator has established an authorized rate of return for our regulated utility businesses, we may not be able to achieve the earnings level authorized. Moreover, in the normal course of business we may place assets in service or incur higher than expected levels of operating expense before rate cases can be filed to recover those costs (this is commonly referred to as regulatory lag). The failure of any regulatory commission to approve requested rate increases on a timely basis to recover costs or to allow an adequate return could adversely impact NW Holdings or NW Naturals financial condition, results of operations and liquidity. As companies with regulated utility businesses, we frequently have dockets open with our regulators. The regulatory proceedings for these dockets typically involve multiple parties, including governmental agencies, consumer, environmental, and other advocacy groups, and other third parties. Each party advocates for the interests that they represent, which may include lower rates, additional regulatory oversight over the company, limitations on growth or phasing out of the gas system, decisions that favor electrification, or advancing other interests. We cannot predict the timing or outcome of these proceedings, or the effects of those outcomes on NW Holdings and NW Naturals results of operations and financial condition. REGULATION, COMPLIANCE AND TAXING AUTHORITY RISK. NW Holdings and NW Natural are subject to governmental regulation, and compliance with local, state and federal requirements, including taxing requirements, and unforeseen changes in or interpretations of such requirements could affect NW Holdings or NW Naturals financial condition and results of operations. NW Holdings and NW Natural are subject to regulation by federal, state and local governmental authorities. We are required to comply with a variety of laws and regulations and to obtain authorizations, permits, approvals and certificates from governmental agencies in various aspects of our business. Significant changes in federal, state, or local governmental leadership can accelerate or amplify changes in existing laws or regulations, or the manner in which they are interpreted or enforced. For instance, the 2020 United States Presidential election resulted in leadership changes in many federal administrative agencies and resulted in a wide range of new policies, executive orders, rules, initiatives and other changes to fiscal, tax, regulation, environmental, climate and other federal policies, many of which have components that affect the energy sector. Similarly, although party leadership in Oregon and Washington did not significantly change in the most recent election, we could continue to face significant legislative, regulatory and other policy changes in the jurisdictions in which we operate. In addition, foreign governments may implement changes to their policies, in response to changes to U.S. policy or otherwise. Although we cannot predict the impact, if any, of these changes to our businesses, they could adversely affect NW Holdings or NW Naturals financial condition and results of operations. Until we know what policy changes are made and how those changes impact our businesses and the business of our competitors over the long term, we will not know if, overall, we will benefit from them or will be negatively affected by them. We cannot predict changes in laws, regulations, interpretations or enforcement or the impact of such changes. Additionally, any failure to comply with existing or new laws and regulations could result in fines, penalties or injunctive measures. For example, under the Energy Policy Act of 2005, the FERC has civil authority under the Natural Gas Act to impose penalties for current violations of nearly $1.5 million per day for each violation. In addition, as the regulatory environment for our businesses increases in complexity, the risk of inadvertent noncompliance may also increase. Changes in regulations, the imposition of additional regulations, and the failure to comply with laws and regulations could negatively influence NW Holdings or NW Naturals operating environment and results of operations. Additionally, changes in federal, state, local or foreign tax laws and their related regulations, or differing interpretations or enforcement of applicable law by a federal, state, local or foreign taxing authority, could result in substantial cost to us and negatively affect our results of operations. Tax law and its related regulations and case law are inherently complex and dynamic. Disputes over interpretations of tax laws may be settled with the taxing authority in examination, through programs like the Compliance Assurance Process (CAP), upon appeal or through litigation. Our judgments may include reserves for potential adverse outcomes regarding tax positions that have been or plan to be taken that may be subject to challenge by taxing authorities. Changes in laws, regulations or adverse judgments and the inherent difficulty in quantifying potential tax effects of business decisions may negatively affect NW Holdings or NW Naturals financial condition and results of operations. Furthermore, certain tax assets and liabilities, such as deferred tax assets and regulatory tax assets and liabilities, are recognized or recorded by NW Holdings or NW Natural based on certain assumptions and determinations made based on available evidence, such as projected future taxable income, tax-planning strategies, and results of recent operations. If these assumptions and determinations prove to be incorrect, the recorded results may not be realized, which may negatively impact the financial results of NW Holdings and NW Natural. There is uncertainty as to how our regulators will reflect the impact of the legislation and other government regulation in rates. The resulting ratemaking treatment may negatively affect NW Holdings or NW Naturals financial condition and results of operations. REPUTATIONAL RISKS. Customers', legislators', regulators' and other third parties opinions of NW Holdings and NW Natural are affected by many factors, including system and fuel reliability and safety, protection of customer information, rates, actual or perceived effects of our products, media coverage, and public sentiment. To the extent that customers, legislators, or regulators have or develop a negative opinion of our businesses, NW Holdings and NW Naturals financial position, results of operations and cash flows could be adversely affected. A number of factors can affect customers, legislators, regulators, and other third parties perception of us or our business including: service interruptions or safety concerns due to failures of equipment or facilities or from other causes, and our ability to promptly respond to such failures; our ability to safeguard sensitive customer information; the timing and magnitude of rate increases; and volatility of rates. Customers', legislators', and regulators' opinions of us can also be affected by media coverage, including the proliferation of social media, which may include information, whether factual or not, that could damage the perception of natural gas, our brand, or our reputation. Although we believe that natural gas serves an important role in helping our region reduce GHG emissions and move to a resilient lower-carbon energy system, certain advocacy groups have opposed the use of natural gas as a fuel source altogether and have pursued policies that limit, restrict, or impose additional costs on, the use of natural gas in a variety of contexts. Concerns raised about the use of natural gas include the potential for natural gas explosions or delivery disruptions, methane leakage along production, transportation and delivery systems, and end-use equipment, and contribution of natural gas energy use to GHG emission levels and global warming. Similarly, concerns have also been raised regarding the use of RNG or hydrogen in place of natural gas. In addition, studies and claims by advocacy groups contend that there are detrimental indoor public health effects associated with the use of natural gas, which may also impact public perception. Shifts in public sentiment due to these concerns or others that may be raised may impact further legislative initiatives, regulatory actions, and litigation, as well as behaviors and perceptions of customers, investors, lawmakers, and regulators. If customers, legislators, regulators, or other third parties have or develop a negative opinion of us and our services, or of natural gas as an energy source generally, this could make it more difficult for us to achieve policy, legislative or regulatory outcomes supportive of our business. Negative opinions could also result in reduced customer growth, sales volumes reductions, increased use of other sources of energy, or difficulties in accessing capital markets. Any of these consequences could adversely affect NW Holdings or NW Naturals financial position, results of operations and cash flows. REGULATORY ACCOUNTING RISK. In the future, NW Holdings or NW Natural may no longer meet the criteria for continued application of regulatory accounting practices for all or a portion of our regulated operations. If we can no longer apply regulatory accounting, we could be required to write off our regulatory assets and precluded from the future deferral of costs not recovered through rates at the time such amounts are incurred, even if we are expected to recover these amounts from customers in the future. COVID-19 Risk PUBLIC HEALTH RISK . The continuation of the novel coronavirus (COVID-19) and the resulting economic conditions, or the emergence of other epidemic or pandemic crises, could materially and adversely affect NW Holdings and NW Naturals business, results of operations, or financial condition. The novel coronavirus (COVID-19), which was declared a pandemic by the World Health Organization in March 2020, has resulted in widespread and severe global, national and local economic and societal disruptions. As recovery from the COVID-19 pandemic continues, resurgences or mutations of the virus, could ultimately adversely affect our business by, among other things: impacting the health, safety, productivity and availability of our employees and contractors; disrupting our access to capital markets or increasing costs of capital affecting our liquidity in the future; reducing demand for natural gas, particularly from commercial and industrial customers that are suffering slow-downs or ultimately close completely due to pandemic effects; reducing customer growth and new meter additions due to less economic, construction or conversion activity; limiting our ability to collect on overdue accounts or disconnect gas service for nonpayment, beyond an amount or period of time acceptable to us; increasing our operating costs for emergency supplies, personal protective equipment, cleaning services and supplies, remote technology and other specific needs; impacting our capital expenditures if construction activities are suspended or delayed; sickening or causing a mandatory quarantine of a large percentage of our workforce, or key workgroups with specialized skill sets, impairing our ability to perform key business functions or execute our business continuity plans; impacting our or our contractors or suppliers ability to recruit and retain qualified personnel or otherwise impairing the functioning of our supply chain or ability to rely on third parties or business partners; adversely affecting the asset values of NW Naturals defined benefit pension plan or causing a failure to maintain sustained growth in pension investments over time, increasing our contribution requirements; limiting, delaying or curtailing entirely, public utility commissions ability to approve or authorize applications or other requests we may make with respect to our regulated businesses; increasing volatility in the price of natural gas; and creating additional cybersecurity vulnerabilities due to ongoing heavy reliance on remote working. Additionally, the long-term effects of COVID-19 or other pandemics could create prolonged unfavorable economic conditions, slowed economic growth, inflation, which may continue to rise, or an economic recession that may result in or be accompanied by unprecedented unemployment rates and declines in the value of certain assets, adversely affecting the income and financial resources of many domestic households and businesses. It is unclear whether governmental responses to these conditions will lessen the severity or duration of any economic effects. Our operational and financial results would likely be affected by such economic conditions. Less new housing construction, fewer conversions to natural gas, higher levels of residential foreclosures and vacancies, and personal and business bankruptcies or reduced spending could all negatively affect our financial condition and results of operations. The ultimate long-term impact of COVID-19 on our business cannot be predicted and will depend on factors beyond our knowledge or control, including resurgences of the pandemic and residual economic effects, actions taken to mitigate its effects, and the extent to which normal economic and operating conditions can continue. Any of these factors could have an adverse effect on our business, outlook, financial condition, and results of operations and cash flows, which could be significant. Growth and Strategic Risks STRATEGIC TRANSACTION RISK. NW Holdings and NW Naturals ability to successfully complete strategic transactions, including mergers, acquisitions, combinations, divestitures, joint ventures, business development projects or other strategic transactions is subject to significant risks, including the risk that required regulatory or governmental approvals may not be obtained, risks relating to unknown problems or liabilities or problems or liabilities undisclosed to us, and the risk that for these or other reasons, we may be unable to achieve some or all of the benefits that we anticipate from such transactions, which could adversely affect NW Holdings or NW Naturals financial condition, results of operations, and cash flows. From time to time, NW Holdings and NW Natural have pursued and may continue to pursue strategic transactions including mergers, acquisitions, combinations, divestitures, joint ventures, business development projects or other strategic transactions, including, but not limited to, investments in RNG projects on a regulated basis by NW Natural and on a non-regulated basis by NW Holdings, as well as acquisitions by NW Holdings in the water and wastewater sectors. Any such transactions involve substantial risks, including the following: such transactions that are contracted for may fail to close for a variety of reasons; the result of such transactions may not produce revenues, earnings or cash flow at anticipated levels, which could, among other things, result in the impairment of any investments or goodwill associated with such transactions; acquired businesses or assets could have environmental, permitting, or other problems for which contractual protections prove inadequate; there may be difficulties in integration or operation costs of new businesses; there may exist liabilities that were not disclosed to us, that exceed our estimates, or for which our rights to indemnification from the seller are limited; we may be unable to obtain the necessary regulatory or governmental approvals to close a transaction or receive approvals granted subject to terms that are unacceptable to us; we may be unable to achieve the anticipated regulatory treatment of any such transaction as part of the transaction approval or subsequent to closing the transaction; or we may be unable to avoid a disposition of assets for a price that is less than the book value of those assets. One or more of these risks could affect NW Holdings and NW Naturals financial condition, results of operations, and cash flows. BUSINESS DEVELOPMENT RISK. NW Holdings and NW Naturals business development projects may not be successful or may encounter unanticipated obstacles, costs, changes or delays that could result in a project being unsuccessful or becoming impaired, which could negatively impact NW Holdings or NW Naturals financial condition, results of operations and cash flows. Business development projects involve many risks. We are currently engaged in several business development projects, including, but not limited to, several water, wastewater and RNG projects. We may also engage in other business development projects such as investments in additional long-term gas reserves, non-regulated investments in RNG projects, and purchasing, marketing and reselling of RNG and its associated attributes, CNG refueling stations, power to gas or hydrogen projects or other similar projects. Our business development activities are subject to uncertainties and changed circumstances and may not reach the scale expected, be successful or perform as anticipated. Additionally, we may not be able to obtain required governmental permits and approvals to complete our projects in a cost-efficient or timely manner, potentially resulting in delays or abandonment of the projects. We could also experience issues such as: technological challenges; ineffective scalability;failure to achieve expected outcomes; unsuccessful business models; startup and construction delays; construction cost overruns; disputes with contractors; the inability to negotiate acceptable agreements such as rights-of-way, easements, construction, gas supply or other material contracts; changes in customer demand, perception or commitment; public opposition to projects; marketing risk and changes in market regulation, behavior or prices, market volatility or unavailability,including markets for RNG and its associated attributes or other environmental attributes; the inability to receive expected tax or regulatory treatment; and operating cost increases. Additionally, we may be unable to finance our business development projects at acceptable costs or within a scheduled time frame necessary for completing the project. Any of the foregoing risks, if realized, could result in business development efforts failing to produce expected financial results and the project investment becoming impaired, and such failure or impairment could have an adverse effect on NW Holdings or NW Naturals financial condition and results of operations. JOINT PARTNER RISK. Investing in business development projects through partnerships, joint ventures or other business arrangements affects our ability to manage certain risks and could adversely impact NW Holdings or NW Naturals financial condition, results of operations and cash flows. We use joint ventures and other business arrangements to manage and diversify the risks of certain development projects, including NW Naturals gas reserves agreements and certain RNG projects. NW Holdings or NW Natural currently has and may further acquire or develop part-ownership interests in other projects in the future, including but not limited to, natural gas, water, wastewater, RNG, or hydrogen projects. Under these arrangements, we may not be able to fully direct the management and policies of the business relationships, and other participants in those relationships may act contrary to our interests, including making operational decisions that could negatively affect our costs and liabilities. In addition, other participants may withdraw from the project, divest important assets, become financially distressed or bankrupt, or have economic or other business interests or goals that are inconsistent with ours. We have in the past and may in the future become involved in disputes with our business partners, which could result in additional cost or divert managements attention. NW Naturals gas reserves arrangements, which operate as a hedge backed by physical gas supplies, involve a number of risks, including: gas production that is significantly less than the expected volumes, or no gas volumes; operating costs that are higher than expected; inherent risks of gas production, including disruption to operations or a complete shut-in of the field; and one or more participants in one of these gas reserves arrangements becoming financially insolvent or acting contrary to NW Naturals interests. For example, while Jonah Energy, the counterparty in NW Naturals gas reserves arrangement, has recently issued asset-backed notes that are rated by credit agencies, Jonah Energy has previously experienced several credit rating downgrades and did not maintain any credit ratings for much of 2022. Although NW Natural intends to continue monitoring Jonah Energys financial condition and take appropriate actions to preserve NW Naturals interests, it does not control Jonah Energys financial condition or continued performance under the gas reserves arrangement. The cost of the original gas reserves venture is currently included in customer rates and additional wells under that arrangement are recovered at specific costs, the occurrence of one or more of these risks could affect NW Naturals ability to recover this hedge in rates. Further, new gas reserves arrangements have not been approved for inclusion in rates, and regulators may ultimately determine to not include all or a portion of future transactions in rates. The realization of any of these situations could adversely impact NW Holdings or NW Naturals financial condition, results of operations and cash flows. CUSTOMER GROWTH RISK. NW Holdings and NW Naturals NGD margin, earnings and cash flow may be negatively affected if we are unable to sustain customer growth rates in our NGD segment. NW Naturals NGD margins and earnings growth have largely depended upon the sustained growth of its residential and commercial customer base due, in part, to the new construction housing market, conversions of customers to natural gas from other energy sources and growing commercial use of natural gas. Building codes recently enacted and others under consideration in our territory may have the effect of reducing our natural gas customer growth rate. For example, effective February 1, 2021, building codes in Washington state require new residential homes to achieve higher levels of energy efficiency based on specified carbon emissions assumptions, which calculate electric appliances to have lower on-site GHG emissions than comparable gas appliances. This increases the cost of new home construction incorporating natural gas depending on a number of factors including home size, equipment configurations, and building envelope measures. Additionally, the Washington State Building Code Council (SBCC) voted in April 2022 to include updates in the state commercial building energy code that are expected to restrict or eliminate the use of gas space and water heating in new commercial construction. In early November, the SBCC voted to include updates to the state residential building energy code that restrict the use of gas space and water heating in residential construction, with certain exceptions including for natural gas-fired heat pumps and hybrid fuel systems.The SBBC commercial and residential rules are expected to become effective July 1, 2023. Certain jurisdictions in Oregon and the State of Oregon are considering similar measures. While we expect these types of codes to be subject to legal challenge, we cannot predict the outcome of any such challenge. Insufficient customer growth, for economic, political, public perception, policy, or other reasons could adversely affect NW Holdings or NW Naturals utility margin, earnings and cash flows. RISK OF COMPETITION. Our NGD business is subject to increased competition which could negatively affect NW Holdings or NW Naturals results of operations. In the residential and commercial markets, NW Naturals NGD business competes primarily with suppliers of electricity, fuel oil, and propane. In the industrial market, NW Natural competes with suppliers of all forms of energy. Competition among these forms of energy is based on price, efficiency, reliability, performance, market conditions, technology, federal, state and local governmental regulation, actual and perceived environmental impacts, and public perception. Technological improvements such as electric heat pumps, batteries or other alternative technologies, or building code restrictions affecting the ability to use certain gas appliances, could erode NW Naturals competitive advantage. If natural gas prices are high relative to other energy sources, or if the cost, environmental impact or public perception of such other energy sources improves relative to natural gas, it may negatively affect NW Naturals ability to secure new customers or retain our existing residential, commercial and industrial customers, which could have a negative impact on our customer growth rate and NW Holdings and NW Naturals results of operations. Our natural gas storage operations compete primarily with other storage facilities and pipelines. Increased competition in the natural gas storage business could reduce the demand for our natural gas storage services, drive prices down for our storage business, and adversely affect our ability to renew or replace existing contracts at rates sufficient to maintain current revenues and cash flows, which could adversely affect NW Holdings and NW Naturals financial condition, results of operations and cash flows. Operational Risks OPERATING RISK. Transporting and storing natural gas and distributing natural gas and water involves numerous risks that may result in accidents and other operating risks and costs, some or all of which may not be fully covered by insurance, and which could adversely affect NW Holdings or NW Naturals financial condition, results of operations and cash flows. NW Holdings and NW Natural are subject to all of the risks and hazards inherent in the businesses of gas and RNG transmission, distribution and storage, water distribution, and wastewater services including: earthquakes, wildfires, floods, storms, landslides and other severe weather incidents and natural hazards; leaks or losses of natural gas or RNG, water or wastewater, or contamination of natural gas, RNG or water by chemicals or compounds, as a result of the malfunction of equipment or facilities or otherwise; damages from third parties; operator errors; negative performance by our storage reservoirs, facilities, or wells that could cause us to fail to meet expected or forecasted operational levels or contractual commitments to our customers or other third parties; problems maintaining, or the malfunction of, pipelines, biodigester facilities, wellbores and related equipment and facilities that form a part of the infrastructure that is critical to the operation of our gas and water distribution, wastewater services, RNG and gas storage facilities; presence of chemicals or other compounds in RNG or natural gas that could adversely affect the performance of the system or end-use equipment; collapse of underground storage reservoirs; inadequate supplies of RNG, natural gas or water or contamination of water supplies; operating costs that are substantially higher than expected; supply chain disruptions, including unexpected price increases, or supply restrictions beyond the control of our suppliers; migration of gas through faults in the rock or to some area of the reservoir where existing wells cannot drain the gas effectively, resulting in loss of the gas; blowouts (uncontrolled escapes of gas from a pipeline or well) or other accidents, fires and explosions; and risks and hazards inherent in the drilling operations associated with the development of gas storage facilities, and wells. For example, TC Pipelines, LP (TC Pipelines) has identified the presence of a chemical substance, dithiazine, at several facilities on the system of its subsidiary, Gas Transmission Northwest (GTN), and those of some upstream and downstream connecting pipeline facilities. A portion of NW Naturals gas supplies from Canada are transported on GTNs pipelines. TC Pipelines reports that dithiazine can drop out of gas streams in a powdery form at some points of pressure reduction (for example, at a regulator), and that in incidents where a sufficient quantity of the material accumulates in certain places, improper functioning of equipment can occur, which can result in increased preventative and corrective action costs. While NW Natural has not detected significant quantities of dithiazine on its system to date, we continue to monitor and could discover increased levels of dithiazine or other compounds on NW Naturals system that could affect the performance of the system or end-use equipment. These and other operational risks could result in disruption of service, personal injury or loss of human life, damage to and destruction of property and equipment, pollution or other environmental damage, breaches of our contractual commitments, and may result in curtailment or suspension of operations, which in turn could lead to significant costs and lost revenues. Further, because our pipeline, storage and distribution facilities are in or near populated areas, including residential areas, commercial business centers, and industrial sites, any loss of human life or adverse financial outcomes resulting from such events could be significant. We could be subject to lawsuits, claims, and criminal and civil enforcement actions. Additionally, we may not be able to maintain the level or types of insurance we desire, and the insurance coverage we do obtain may contain large deductibles or fail to cover certain hazards or cover all potential losses. The occurrence of any operating risks not covered by insurance could adversely affect NW Holdings or NW Naturals financial condition, results of operations and cash flows. SAFETY REGULATION RISK. NW Holdings and NW Natural may experience increased federal, state and local regulation of the safety of our systems and operations, which could adversely affect NW Holdings or NW Naturals operating costs and financial results. The safety and protection of the public, our customers and our employees is and will remain our top priority. We are committed to consistently monitoring, maintaining, and upgrading our distribution systems and storage operations to ensure that RNG, natural gas and water is acquired, stored and delivered safely, reliably and efficiently. Natural gas operators are subject to robust, ongoing federal, state and local regulatory oversight, which intensifies in response to incidents. For example, the 2020 Protecting our Infrastructure of Pipelines and Enhancing Safety Act (PIPES Act) prompted PHSMA to issue three new rulemakings impacting transmission lines, gathering lines, and valve automation in response to past incidents in other parts of the country. Proposed rulemakings planned for 2023 by the Pipeline and Hazardous Materials Safety Administration (PHMSA), include regulations related to the detection and repair of leaks and safety of gas distribution pipelines. In addition, our workplaces are subject to the requirements of the Department of Transportation, through the Federal Motor Carrier Safety Administration, and the Occupational Safety and Health Administration, as well as state and local statutes and regulations that regulate the protection of the health and safety of workers. The failure to comply with these requirements or general industry standards, including keeping adequate records or preventing occupational injuries or exposure, could expose us to civil or criminal liability, enforcement actions, and regulatory fines and penalties that may not be recoverable through our rates and could have a material adverse effect on our business, financial condition, results of operations and cash flows. We intend to work diligently with industry associations and federal and state regulators to comply with these regulations and other new laws. We expect there to be increased costs associated with compliance, and those costs could be significant. If these costs are not recoverable in our customer rates, they could have a negative impact on NW Holdings and NW Naturals operating costs and financial results. RELIANCE ON THIRD PARTIES TO SUPPLY NATURAL GAS, RNG AND ENVIRONMENTAL ATTRIBUTES OR CREDITS RISK. NW Natural relies on third parties to supply the natural gas, RNG and environmental attributes or credits in its NGD segment, and limitations on NW Naturals ability to obtain supplies, or failure to receive expected supplies, could have an adverse impact on NW Holdings or NW Naturals financial results. NW Naturals ability to secure natural gas, RNG and environmental attributes or credits depends upon its ability to purchase and receive delivery of them from third parties. NW Natural, and in some cases its suppliers, does not have control over the availability of natural gas, RNG or environmental attributes or credits, competition for those supplies, disruptions in those supplies, priority allocations on transmission pipelines, markets for those supplies, or pricing and other terms related to such supplies. Additionally, third parties on whom NW Natural relies may fail to deliver supplies for which it has contracted. For example, in October, 2018, a 36-inch pipeline near Prince George, British Columbia owned by Enbridge ruptured, disrupting natural gas flows from Canada into Washington while the ruptured pipeline and an adjacent pipeline were assessed and the ruptured pipeline was repaired. Once repaired, pressurization levels for those pipelines were reduced for a significant period of time for assessment and testing. If NW Natural is unable or limited in its ability to obtain natural gas, RNG or environmental attributes or credits from its current suppliers or new sources, it may not be able to meet customers' gas requirements or regulatory or compliance requirements, and would likely incur costs associated with actions necessary to mitigate service disruptions or regulatory compliance, which could significantly and negatively impact NW Holdings and NW Naturals results of operations. SINGLE TRANSPORTATION PIPELINE RISK. NW Natural relies on a single pipeline company for the transportation of gas to its service territory, a disruption, limitation, or inadequacy of which could adversely impact its ability to meet customers gas requirements, which could significantly and negatively impact NW Holdings and NW Naturals results of operations. NW Naturals distribution system is directly connected to a single interstate pipeline, which is owned and operated by Northwest Pipeline. The pipelines gas flows are bi-directional, transporting gas into the Portland metropolitan market from two directions: (1) the north, which brings supplies from the British Columbia and Alberta supply basins; and (2) the east, which brings supplies from the Alberta and the U.S. Rocky Mountain supply basins. If there is a rupture or inadequate capacity in, or supplies to maintain adequate pressures in, the pipeline, NW Natural may not be able to meet its customers gas requirements and we would likely incur costs associated with actions necessary to mitigate service disruptions, both of which could significantly and negatively impact NW Holdings and NW Naturals results of operations. THIRD PARTY PIPELINE RISK. NW Naturals gas storage business depends on third-party pipelines that connect our storage facilities to interstate pipelines, the failure or unavailability of which could adversely affect NW Holdings or NW Naturals financial condition, results of operations and cash flows. Our gas storage facilities are reliant on the continued operation of a third-party pipeline and other facilities that provide delivery options to and from our storage facilities. Because we do not own all of these pipelines, their operations are not within our control. If the third-party pipeline to which we are connected were to become unavailable for current or future withdrawals or injections of natural gas due to repairs, damage to the infrastructure, lack of capacity or other reasons, our ability to operate efficiently and satisfy our customers needs could be compromised, thereby potentially having an adverse impact on NW Holdings or NW

Naturals financial condition, results of operations and cash flows. WORKFORCE RISK. NW Holdings and NW Naturals businesses are heavily dependent on being able to attract and retain qualified employees and maintain a competitive cost structure with market-based salaries and employee benefits, and workforce disruptions could adversely affect NW Holdings or NW Naturals operations and results. NW Holdings and NW Naturals ability to implement our business strategy and serve our customers is dependent upon our continuing ability to attract and retain diverse, talented professionals and a technically skilled workforce, and being able to transfer the knowledge and expertise of our workforce to new and increasingly diverse employees as our largely older workforce retires. A significant portion of our workforce is currently eligible or will reach retirement eligibility within the next five years, which will require that we attract, train and retain skilled workers to prevent loss of institutional knowledge or skills gaps. We face competition for qualified personnel with specific skillsets. This competition is elevated by the record low unemployment in Oregon and may result in increased pressure on wages or other challenges in recruiting or retaining personnel. Without an appropriately skilled workforce, our ability to provide quality service and meet our regulatory requirements will be challenged and this could negatively impact NW Holdings' and NW Naturals earnings. Additionally, approximately half of NW Natural workers are represented by the OPEIU Local No. 11 AFL-CIO and are covered by a collective bargaining agreement that extends to May 31, 2024. Disputes with the union representing NW Natural employees over terms and conditions of their agreement, or failure to timely and effectively renegotiate the agreement upon its expiration, could result in instability in our labor relationship or other labor disruptions that could impact the timely delivery of gas and other services from our utility and storage facilities, which could strain relationships with customers and state regulators and cause a loss of revenues. The collective bargaining agreements may also limit our flexibility in dealing with NW Naturals workforce, and the ability to change work rules and practices and implement other efficiency-related improvements to successfully compete in todays challenging marketplace, which may negatively affect NW Holdings and NW Naturals financial condition and results of operations. Environmental Risks ENVIRONMENTAL LIABILITY RISK. Certain of NW Naturals, and possibly NW Holdings, properties and facilities may pose environmental risks requiring remediation, the costs of which are difficult to estimate and which could adversely affect NW Holdings and NW Naturals financial condition, results of operations, and cash flows. NW Natural owns, or previously owned, properties that require environmental remediation or other action. NW Holdings or NW Natural may now, or in the future, own other properties that require environmental remediation or other action. NW Natural and NW Holdings accrue all material loss contingencies relating to these properties. A regulatory asset at NW Natural has been recorded for estimated costs pursuant to a deferral order from the OPUC and WUTC. In addition to maintaining regulatory deferrals, NW Natural settled with most of its historical liability insurers for only a portion of the costs it has incurred to date and expects to incur in the future. To the extent amounts NW Natural recovered from insurance are inadequate and it is unable to recover these deferred costs in utility customer rates, NW Natural would be required to reduce its regulatory assets which would result in a charge to earnings in the year in which regulatory assets are reduced. In addition, in Oregon, the OPUC approved the SRRM, which limits recovery of deferred amounts to those amounts which satisfy an annual prudence review and an earnings test that requires NW Natural to contribute additional amounts toward environmental remediation costs above approximately $10 million in years in which NW Natural earns above its authorized ROE. To the extent NW Natural earns more than its authorized ROE in a year, it would be required to cover environmental expenses greater than the $10 million with those earnings that exceed its authorized ROE. The OPUC ordered a review of the SRRM in 2018 or when we obtain greater certainty of environmental costs, whichever occurred first. We submitted information for review in 2018, and believe we could be subject to further review. Similarly, in October 2019, the WUTC authorized an ECRM, which allows for recovery of certain past deferred and future prudently incurred remediation costs allocable to Washington through application of insurance proceeds and collections from customers, subject to an annual prudence determination. These ongoing prudence reviews, or with respect to the SRRM, the earnings test, or the periodic review could reduce the amounts NW Natural is allowed to recover, and could adversely affect NW Holdings or NW Naturals financial condition, results of operations and cash flows. Moreover, we may have disputes with regulators and other parties as to the severity of particular environmental matters, what remediation efforts are appropriate, whether natural resources were damaged, and the portion of the costs or claims NW Natural or NW Holdings should bear. We cannot predict with certainty the amount or timing of future expenditures related to environmental investigations, remediation or other action, the portions of these costs allocable to NW Natural or NW Holdings, or disputes or litigation arising in relation thereto. Environmental liability estimates are based on current remediation technology, industry experience gained at similar sites, an assessment of probable level of responsibility, and the financial condition of other potentially responsible parties. However, it is difficult to estimate such costs due to uncertainties surrounding the course of environmental remediation, the preliminary nature of certain site investigations, natural recovery of the site, unavoidable limitations associated with environmental investigations and remedial technologies, evolving science, and the application of environmental laws that impose joint and several liabilities on all potentially responsible parties. These uncertainties and disputes arising therefrom could lead to further adversarial administrative proceedings or litigation, with associated costs and uncertain outcomes, all of which could adversely affect NW Holdings or NW Naturals financial condition, results of operations and cash flows. ENVIRONMENTAL REGULATION COMPLIANCE RISK. NW Holdings and NW Natural are subject to environmental regulations for our ongoing businesses, compliance with which or failure to comply with, could adversely affect our operations or financial results. NW Holdings and NW Natural are subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local governmental authorities relating to protection of the environment, including those legal requirements that govern discharges of substances into the air and water, the management and disposal of hazardous substances and waste, groundwater quality and availability, plant and wildlife protection, the emitting of greenhouse gases, and other aspects of environmental regulation. For example, our natural gas operations are subject to reporting requirements to a number of governmental authorities including, but not limited to, the Environmental Protection Agency (EPA), the Oregon Department of Environmental Quality (ODEQ), and the Washington State Department of Ecology regarding greenhouse gas emissions. We are also required to reduce emissions of GHGs over time in accordance with the Oregon Climate Protection Program and the Washington Climate Commitment Act. These and other current and future additional environmental regulations at the local, state or national level could result in increased compliance costs or additional operating restrictions, which may or may not be recoverable in customer rates, through insurance or otherwise. If these costs are not recoverable, or if these regulations reduce the desirability, availability, or cost-competitiveness of natural gas, they could have an adverse effect on NW Holdings or NW Naturals operations or financial condition. Furthermore, failure to comply with such laws or regulations could subject us to possible enforcement actions, financial liability or litigation, any of which could adversely affect NW Holdings or NW Naturals financial condition and results of operations. GLOBAL CLIMATE CHANGE RISK. Our businesses may be subject to physical risks associated with climate change, all of which could adversely affect NW Holdings or NW Naturals financial condition, results of operations and cash flows. Climate change may cause physical risks, including an increase in sea level, intensified storms, water scarcity, wildfire susceptibility and intensity and changes in weather conditions, such as changes in precipitation, average temperatures and extreme wind or other extreme weather events or climate conditions. Moreover, a significant portion of the nations gas infrastructure is located in areas susceptible to storm damage that could be aggravated by wetland and barrier island erosion, which could give rise to gas supply interruptions and price spikes. These and other physical changes could result in disruptions to natural gas production and transportation systems potentially increasing the cost of gas and affecting our natural gas businesses ability to procure or transport gas to meet customer demand. These changes could also affect our distribution systems resulting in increased maintenance and capital costs, disruption of service, regulatory actions and lower customer satisfaction. Similar disruptions could occur in NW Holdings water utility businesses. Additionally, to the extent that climate change adversely impacts the economic health or weather conditions of our service territory directly, it could adversely impact customer demand or our customers ability to pay. Such physical risks could have an adverse effect on NW Holdings or NW Naturals financial condition, results of operations, and cash flows. PUBLIC PERCEPTION AND POLICY RISK. Changes in public sentiment or public policy with respect to natural gas, including through local, state or federal laws or legislation or other regulation (including ballot initiatives, executive orders or regulatory codes) or litigation, could adversely affect NW Holdings or NW Naturals financial condition, results of operations and cash flows. There are a number of international, federal, state, and local legislative, legal, regulatory and other initiatives being proposed and adopted in an attempt to measure, control or limit the effects of global warming and climate change, including greenhouse gas (GHG) emissions such as carbon dioxide, nitrous oxide, and methane. Legislation or other forms of public policy or regulation that aim to reduce GHG emissions at the federal, state, or local level have and could continue to take a variety of forms including, but not limited to, GHG emissions limits, reporting requirements, carbon taxes, requirements to purchase carbon credits, building codes, increased efficiency standards, additional charges to fund energy efficiency activities or other regulatory actions, and incentives or mandates to conserve energy, or use renewable energy sources. Federal, state, or local governments may provide tax advantages and other subsidies to support alternative energy sources, withdraw funding from fossil fuel sources, mandate the use of specific fuels or technologies, prohibit the use of natural gas, or promote research into new technologies to reduce the cost and increase the scalability of alternative energy sources. In 2021, the United States rejoined the Paris Agreement on Climate Change, and the United States Presidential administration has issued executive orders aimed at reducing GHG emissions, has declared climate change a national security priority, and continues to consider a wide range of policies, executive orders, rules, legislation and other initiatives to address climate change. For example, the Inflation Reduction Act of 2022 (IRA), was signed into law in August 2022 and includes a number of energy and climate related provisions including funding for the EPA to improve GHG reporting and enforcement, as well as a methane fee applicable to activities associated with gas production and processing facilities, transmission pipelines and certain storage facilities. The U.S. Congress may also pass federal climate change legislation in the future. Additionally, other federal agencies have taken or are expected to take actions related to climate change. For example, in March 2022, the Securities and Exchange Commission (SEC) proposed new rules relating to the disclosure of a range of climate-related matters, PHMSA is expected to prepare regulations and other actions to limit methane emissions and the Commodities Futures Trading Commission (CFTC) has indicated it intends to take actions related to oversight of climate-related financial risks as pertinent to the derivatives and underlying commodities markets. Similarly, other federal agencies and regulations, including but not limited to the Consumer Products Safety Commission, the U.S. Department of Treasury, Federal Acquisitions Regulations, and others have indicated impending actions related to regulation related to climate change. At the state level, the State of Washington has enacted the Climate Commitment Act (CCA), which establishes a comprehensive program that provides an overall limit for GHG emissions from major sources in the state that begins on January 1, 2023 and declines yearly to 95% below 1990 levels by 2050. Similarly, in Oregon, in March 2020, the Oregon Governor issued an executive order (EO) establishing GHG emissions reduction goals and directing state agencies and commissions (including the ODEQ and the OPUC) to facilitate such GHG emission goals. In December 2021, the ODEQ concluded its process and issued final cap and reduce rules for the Climate Protection Program (CPP), which became effective January 1, 2022. The CPP outlines GHG emissions reduction goals of 50% by 2035 and 90% by 2050 from a 1990 baseline. NW Natural is subject to both the CCA and CPP. We expect that there will be additional efforts to address climate change in the 2023 legislative sessions in both Oregon and Washington and we cannot predict whether the legislatures will pass any climate related legislation and the potential impact any such legislation may have on the Company. In addition, the State of Washington has enacted and the State of Oregon and some local jurisdictions are considering building codes that could have the effect of disfavoring or disallowing natural gas in residential or commercial new construction or conversions, including locations within our service territory, such as the recent actions by the City of Eugene to disallow gas in new residential construction beginning with permits issued in mid-2023. A number of local and county jurisdictions are also proposing or passing renewable energy resolutions or other measures in an effort to accelerate renewable energy goals. Such current or future legislation, regulation or other initiatives (including executive orders, ballot initiatives or ordinances) could impose on our natural gas businesses operational requirements or restrictions, additional charges to fund energy efficiency initiatives, or levy a tax based on carbon content. In addition, certain jurisdictions, including San Francisco, Seattle, and New York have enacted measures to ban or discourage the use of new natural gas hookups in residential or other buildings. Other jurisdictions, including several in our service territory, such as the city of Milwaukie, have considered or are currently considering similar restrictions or other measures discouraging the use of natural gas, such as limitations or bans on the use of natural gas in new construction, requiring the conversion of buildings to electric heat, or adopting policies or incentives to encourage the use of electricity in lieu of natural gas. Such restrictions could adversely impact customer growth or usage and could adversely impact our ability to recover costs and maintain reasonable customer rates. In addition, certain cities, local jurisdictions and private parties have initiated lawsuits against companies related to climate change impacts, GHG emissions or climate-related disclosures. While NW Natural has not been subject to such litigation to date, such climate-related claims or actions could be costly to defend and could negatively impact our business, reputation, financial condition, and results of operations. NW Natural believes natural gas has an important role in moving the Pacific Northwest to a low carbon future, and to that end is developing programs and measures to reduce carbon emissions. However, NW Naturals efforts may not happen quickly enough to keep pace with legislation or other regulation, legal changes or public sentiment, or may be more costly or not be as effective as expected. Any of these initiatives, or our unsuccessful response to them, could result in us incurring additional costs to comply with the imposed policies, regulations, restrictions or programs, provide a cost or other competitive advantage to energy sources other than natural gas, reduce demand for natural gas, restrict our customer growth, impose costs or restrictions on end users of natural gas, impact the prices we charge our customers, increase the likelihood of litigation, impose increased costs on us associated with the adoption of new infrastructure and technology to respond to such requirements which may or may not be recoverable in customer rates, and could negatively impact public perception of our services or products that negatively diminishes the value of our brand, all of which could adversely affect NW Holdings or NW Naturals business operations, financial condition and results of operations. Business Continuity and Technology Risks BUSINESS CONTINUITY RISK. NW Holdings and NW Natural may be adversely impacted by local or national disasters, political unrest, terrorist activities, cyber-attacks or data breaches, and other extreme events to which we may not be able to promptly respond, which could adversely affect NW Holdings or NW Naturals operations or financial condition. Local or national disasters, political unrest, terrorist activities, cyber-attacks and data breaches, and other extreme events are a threat to our assets and operations. Companies in critical infrastructure industries may face a heightened risk due to being the target of, and having heightened exposure to, acts of terrorism or sabotage, including physical and security breaches of our physical infrastructure and information technology systems in the form of cyber-attacks or other forms of attacks. These attacks could, among other things, target or impact our technology or mechanical systems that operate our distribution, transmission or storage facilities and result in a disruption in our operations, damage to our system and inability to meet customer requirements. In addition, the threat of terrorist activities could lead to increased economic instability and volatility in the price of RNG, natural gas or other necessary commodities that could affect our operations. Threatened or actual national disasters or terrorist activities may also disrupt capital or bank markets and our ability to raise capital or obtain debt financing, or impact our suppliers or our customers directly. Local disaster or civil unrest could result in disruption of our infrastructure or part of our workforce being unable to operate or maintain our infrastructure or perform other tasks necessary to conduct our business. A slow or inadequate response to events may have an adverse impact on our operations and earnings. We may not be able to maintain sufficient insurance to cover all risks associated with local and national disasters, terrorist activities, cyber-attacks and other attacks or events. Additionally, large scale natural disasters or terrorist attacks could destabilize the insurance industry making the insurance we do have unavailable, which could increase the risk that an event could adversely affect NW Holdings or NW Naturals operations or financial results. RELIANCE ON TECHNOLOGY RISK. NW Holdings and NW Naturals efforts to integrate, consolidate and streamline each of their operations has resulted in increased reliance on technology, the failure of which could adversely affect NW Holdings or NW Naturals financial condition and results of operations. NW Holdings and NW Natural have undertaken a variety of initiatives to integrate, standardize, centralize and streamline operations. These efforts have resulted in greater reliance on technological tools such as, at NW Natural: an enterprise resource planning system, a digital dispatch system, an automated meter reading system, a web-based ordering and tracking system, and other similar

technological tools and initiatives. Our future success will depend, in part, on our ability to anticipate and adapt to technological changes in a cost-effective manner and to offer, on a timely basis, services that meet customer demands and evolving industry standards. New technologies may emerge that could be superior to, or may not be compatible with, some of our existing technologies, and may require us to make significant expenditures to remain competitive. We continue to implement technology to improve our business processes and customer interactions. In addition, our various existing information technology systems require periodic modifications, upgrades and/or replacement. For example, NW Natural has recently implemented upgrades to its SAP system and intends to replace its customer information system in the near future. There are various risks associated with these systems in addition to upgrades and replacements, including hardware and software failure, communications failure, data distortion or destruction, unauthorized access to data, misuse of proprietary or confidential data, unauthorized control through electronic means, programming mistakes and other inadvertent errors or deliberate human acts. In addition, we are dependent on a continuing flow of important components and appropriately skilled individuals to maintain and upgrade our information technology systems. Our suppliers have faced disruptions due to COVID-19 and may face additional production or import delays due to natural disasters, strikes, lock-outs, political unrest, pandemics (including COVID-19) or other such circumstances. Technology services provided by third-parties also could be disrupted due to events and circumstances beyond our control which could adversely impact our business, financial condition and results of operations. Any modifications, upgrades, system maintenance or replacements subject us to inherent costs and risks, including potential disruption of our internal control structure, substantial capital expenditures, additional administrative and operating expenses, retention of sufficiently skilled personnel to implement and operate the new systems, and other risks and costs of delays or difficulties in transitioning to new systems or of integrating new systems into our current systems. In addition, the difficulties with implementing new technology systems may cause disruptions in our business operations and have an adverse effect on our business and operations, if not anticipated and appropriately mitigated. There is also risk that we may not be able to recover all costs associated with projects to improve our technological capabilities, which may adversely affect NW Holdings or NW Naturals financial condition and results of operations.
CYBERSECURITY RISK. NW Holdings and NW Naturals status as an infrastructure services provider coupled with its reliance on technology could result in a security breach which could adversely affect NW Holdings or NW Naturals financial condition and results of operations. Although we take precautions to protect our technology systems and are not aware of any material security breaches to date, there is no guarantee that the procedures we have implemented to protect against unauthorized access to secured data and systems, including our industrial controls and other information technology systems, are adequate to safeguard against all security breaches or other cyberattacks. Additionally, the facilities and systems of clients,

suppliers and third party service providers also could be vulnerable to cyber risks and attacks, and such third party systems may be interconnected to our systems. Therefore, an event caused by cyberattacks or other malicious act at an interconnected third party could impact our business and facilities similarly. As these potential cyber security attacks become more common and sophisticated, we could be required to incur costs to strengthen our systems or maintain insurance coverage against potential losses. Moreover, a variety of regulatory agencies are increasingly focused on cybersecurity risks, and specifically in critical infrastructure sectors. For example, the Transportation Security Administration (TSA) has published multiple security directives and is currently in the process of implementing formal rules mandating cybersecurity actions for critical pipeline owners and operators. Failure to timely and effectively meet the requirements of these directives or other cybersecurity regulations could result in fines or other penalties. We are continuing to evaluate the potential costs of implementation of these directives, and there is no assurance that we will be able to continue to recover in rates costs associated with such compliance. In addition, our businesses could experience breaches of security pertaining to sensitive customer, employee, and vendor information maintained by us in the normal course of business, which could adversely affect our reputation, diminish customer confidence, disrupt operations, materially increase the costs we incur to protect against these risks, and subject us to possible financial liability or increased regulation or litigation. All of these risks could adversely affect NW Holdings or NW Naturals financial condition and results of operations. Financial and Economic Risks HOLDING COMPANY DIVIDEND RISK. As a holding company, NW Holdings depends on its operating subsidiaries, including NW Natural, to meet financial obligations and the ability of NW Holdings to pay dividends on its common stock is dependent on the receipt of dividends and other payments from its subsidiaries, including NW Natural. As a holding company, NW Holdings only significant assets are the stock and membership interests of its operating subsidiaries, which at this time is primarily NW Natural. NW Holdings direct and indirect subsidiaries are separate and distinct legal entities, managed by their own boards of directors, and have no obligation to pay any amounts to their respective shareholders, whether through dividends, loans or other payments. The ability of these companies to pay dividends or make other distributions on their common stock is subject to, among other things: their results of operations, net income, cash flows and financial condition, as well as the success of their business strategies and general economic and competitive conditions; the prior rights of holders of existing and future debt securities and any future preferred stock issued by those companies; and any applicable legal restrictions. In addition, the ability of NW Holdings subsidiaries to pay upstream dividends and make other distributions is subject to applicable state law and regulatory restrictions. Under the OPUC and WUTC regulatory approvals for the holding company formation, if NW Natural ceases to comply with credit and capital structure requirements approved by the OPUC and WUTC, it will not, with limited exceptions, be permitted to pay dividends to NW Holdings. Under the OPUC and WUTC orders authorizing the holding company reorganization, NW Natural may not pay dividends or make distributions to NW Holdings if NW Naturals credit ratings and common equity levels fall below specified ratings and levels. If NW Naturals long-term secured credit ratings are below A- for SP and A3 for Moodys, dividends may be issued so long as NW Naturals common equity is 45% or above. If NW Naturals long-term secured credit ratings are below BBB for SP and Baa2 for Moodys, dividends may be issued so long as NW Naturals common equity is 46% or above. Dividends may not be issued if NW Naturals long-term secured credit ratings fall to BB+ or below for SP or Ba1 or below for Moodys, or if NW Naturals common equity is below 44%. The ratio is measured using common equity and long-term debt excluding imputed debt or debt-like lease obligations, and is determined on a preceding or projected 13-month basis. EMPLOYEE BENEFIT RISK. The cost of providing pension and postretirement healthcare benefits is subject to changes in pension assets and liabilities, changing employee demographics and changing actuarial assumptions, which may have an adverse effect on NW Holdings or NW Naturals financial condition, results of operations and cash flows. Until NW Natural closed the pension plans to new hires, which for non-union employees was in 2006 and for union employees was in 2009, it provided pension plans and postretirement healthcare benefits to eligible full-time utility employees and retirees. Approximately 30% of NW Naturals current utility employees were hired prior to these dates, and therefore remain eligible for these plans. Other businesses we acquire may also have pension plans. The costs to NW Natural, or the other applicable businesses we may acquire, for providing such benefits is subject to change in the market value of the pension assets, changes in employee demographics including longer life expectancies, increases in healthcare costs, current and future legislative changes, and various actuarial calculations and assumptions. The actuarial assumptions used to calculate our future pension and postretirement healthcare expenses may differ materially from actual results due to significant market fluctuations and changing withdrawal rates, wage rates, interest rates and other factors. These differences may result in an adverse impact on the amount of pension contributions, pension expense or other postretirement benefit costs recorded in future periods. Sustained declines in equity markets and reductions in bond rates may have a material adverse effect on the value of the pension fund assets and liabilities. In these circumstances, NW Natural may be required to recognize increased contributions and pension expense earlier than it had planned to the extent that the value of pension assets is less than the total anticipated liability under the plans, which could have a negative impact on NW Holdings and NW Naturals financial condition, results of operations and cash flows. HEDGING RISK. NW Holdings and NW Naturals risk management policies and hedging activities cannot eliminate the risk of commodity price movements and other financial market risks, and hedging activities may expose us to additional liabilities for which rate recovery may be disallowed, which could result in an adverse impact on NW Holdings and NW Naturals operating revenues, costs, derivative assets and liabilities and operating cash flows. NW Naturals gas purchasing requirements expose us to risks of commodity price movements, while NW Holdings and NW Naturals use of debt and equity financing exposes us to interest rate, liquidity and other financial market risks. We attempt to manage these exposures with both financial and physical hedging mechanisms, including NW Naturals gas reserves transactions which are hedges backed by physical gas supplies and interest rate hedging arrangements at NW Holdings and NWN Water. While we have risk management procedures for hedging in place, they may not always work as planned and cannot entirely eliminate the risks associated with hedging. Additionally, our hedging activities may cause us to incur additional expenses to obtain the hedge. We do not hedge our entire interest rate or commodity cost exposure, and the unhedged exposure will vary over time. Gains or losses experienced through NW Naturals hedging activities, including carrying costs, generally flow through NW Naturals PGA mechanism or are recovered in future general rate cases. However, the hedge transactions NW Natural enters into for utility purposes are subject to a prudence review by the OPUC and WUTC, and, if found imprudent, those expenses may be, and have been previously, disallowed, which could have an adverse effect on NW Holdings or NW Naturals financial condition and results of operations. In addition, our actual business requirements and available resources may vary from forecasts, which are used as the basis for hedging decisions and could cause our exposure to be more or less than anticipated. Moreover, if NW Naturals derivative instruments and hedging transactions do not qualify for regulatory deferral and it does not elect hedge accounting treatment under U.S. GAAP, NW Holdings or NW Naturals results of operations and financial condition could be adversely affected. NW Holdings and NW Natural also have credit-related exposure to derivative counterparties. Counterparties owing NW Holdings, NW Natural or their respective subsidiaries money or physical natural gas commodities could breach their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements to meet our normal business requirements. In that event, NW Holdings or NW Naturals financial results could be adversely affected. Additionally, under most of NW Naturals hedging arrangements, any downgrade of its senior unsecured long-term debt credit rating could allow its counterparties to require NW Natural to post cash, a letter of credit or other form of collateral, which would expose NW Natural to additional costs and may trigger significant increases in borrowing from its credit facilities or equity contribution needs from NW Holdings, if the credit rating downgrade is below investment grade. Further, based on current interpretations, each of NW Holdings, NW Natural and NWN Water is not considered a "swap dealer" or "major swap participant" in 2022, so we are exempt from certain requirements under the Dodd-Frank Act. If we are unable to claim this exemption, we could be subject to higher costs for our derivatives activities, and such higher costs could have a negative impact on NW Holdings and NW Naturals operating costs and financial results. GAS PRICE RISK. Higher natural gas commodity prices and volatility in the price of gas may adversely affect NW Naturals NGD business, whereas lower gas price volatility may adversely affect NW Naturals gas storage business, negatively affecting NW Holdings and NW Naturals results of operations and cash flows. The cost of natural gas is affected by a variety of factors, including weather, changes in demand, the level of production and availability of natural gas supplies, transportation constraints, availability and cost of pipeline capacity, federal, state and local energy and environmental policy, regulation and legislation, natural disasters and other catastrophic events, national and worldwide economic and political conditions, and the price and availability of alternative fuels. In 2021 and 2022 there was increased pricing and volatility in the current and forward gas markets. At NW Natural, the cost we pay for natural gas is generally passed through to customers through an annual PGA rate adjustment. If gas prices were to increase significantly and remain higher, it could raise the cost of energy to NW Naturals customers, potentially causing those customers to conserve or switch to alternate sources of energy. Sustained significant price increases could also cause new home builders and commercial developers to select alternative energy sources. Decreases in the volume of gas NW Natural sells could reduce NW Holdings or NW Naturals earnings, and a decline in customers could slow growth in future earnings. Additionally, notwithstanding NW Naturals current rate structure, higher gas costs could result in increased pressure on the OPUC or the WUTC to seek other means to reduce NW Naturals rates, which also could adversely affect NW Holdings and NW Naturals results of operations and cash flows. Temporary gas price increases can also adversely affect NW Holdings and NW Naturals operating cash flows, liquidity and results of operations because a portion (10% or 20%) of any difference between the estimated average PGA gas cost in rates and the actual average gas cost incurred is recognized as current income or expense. Temporary or sustained higher gas prices may also cause NW Natural to experience an increase in short-term debt and temporarily reduce liquidity because it pays suppliers for gas when it is purchased, which can be in advance of when these costs are recovered through rates. Significant increases in the price of gas can also slow collection efforts as customers experience increased difficulty in paying their higher energy bills, leading to higher than normal delinquent accounts receivable resulting in greater expense associated with collection efforts and increased bad debt expense. INABILITY TO ACCESS CAPITAL MARKET RISK. NW Holdings or NW Naturals inability to access capital, or significant increases in the cost of capital, could adversely affect NW Holdings or NW Naturals financial condition and results of operations. NW Holdings and NW Naturals ability to obtain adequate and cost effective short-term and long-term financing depends on maintaining investment grade credit profiles, perceptions of our business in capital markets, and the existence of liquid and stable financial markets. NW Holdings relies on access to equity and bank markets to finance equity contributions to subsidiaries and other business requirements. NW Natural relies on access to capital and bank markets, including commercial paper and bond markets, to finance its operations, construction expenditures and other business requirements, and to refinance maturing debt that cannot be funded entirely by internal cash flows. Disruptions in capital markets, including but not limited to, pandemics, political unrest, inflationary pressures, recessionary pressures, or rising interest rates could adversely affect our ability to access short-term and long-term financing or refinance maturing indebtedness. Our access to funds under committed credit facilities, which are currently provided by a number of banks, is dependent on the ability of the participating banks to meet their funding commitments. Those banks may not be able to meet their funding commitments if they experience shortages of capital and liquidity. Disruptions in the bank or capital financing markets as a result of economic uncertainty, changing or increased regulation of the financial sector, or failure of major financial institutions, or disruptions in credit markets, could adversely affect NW Holdings and NW Naturals access to capital and negatively impact our ability to run our businesses, achieve NW Naturals authorized rate of return, and make strategic investments. Furthermore, recent trends toward investments that are perceived to be green or sustainable could shift capital away from, or increase the cost of capital for, our natural gas business. We believe our business is an important component of a low carbon future and are striving to decarbonize our systems. Nevertheless, perceptions in the financial markets could differ or outpace our decarbonization progress and result in a shift funding away from, or limit or restrict certain forms of funding for, natural gas businesses. NW Natural is currently rated by SP and Moodys and a negative change in its credit ratings, particularly below investment grade, could adversely affect its cost of borrowing and access to sources of liquidity and capital. Such a downgrade could further limit its access to borrowing under available credit lines. Additionally, downgrades in its current credit ratings below investment grade could cause additional delays in NW Natural's ability to access the capital markets while it seeks supplemental state regulatory approval, which could hamper its ability to access credit markets on a timely basis. NW Holdings' credit profile is largely supported by NW Naturals credit ratings and any negative change in NW Naturals credit ratings would likely negatively impact NW Holdings access to sources of liquidity and capital and cost of borrowing. A credit downgrade to NW Natural, or resulting negative impact on NW Holdings, could also require additional support in the form of letters of credit, cash or other forms of collateral and otherwise adversely affect NW Holdings' or NW Naturals financial condition and results of operations. IMPAIRMENT OF LONG-LIVED ASSETS OR GOODWILL RISK . Impairments of the value of long-lived assets or goodwill could have a material effect on NW Holdings or NW Naturals financial condition, or results of operations. NW Holdings and NW Natural review the carrying value of long-lived assets other than goodwill whenever events or changes in circumstances indicate the carrying amount of the assets might not be recoverable. The determination of recoverability is based on the undiscounted net cash flows expected to result from the operation of such assets. Projected cash flows depend on the future operating costs and projected revenues associated with the asset. We review the carrying value of goodwill annually or whenever events or changes in circumstances indicate that such carrying value may not be recoverable. A goodwill impairment analysis begins with a qualitative analysis of events and circumstances. If the qualitative assessment indicates that the carrying value may be at risk, we will perform a quantitative assessment and recognize a goodwill impairment for any amount in which the fair value of a reporting unit exceeds its fair value. NW Holdings' total goodwill was $149.3 million as of December 31, 2022 and $70.6 million as of December 31, 2021. All of our goodwill is related to water and wastewater acquisitions. There have been no impairments recognized for the water and wastewater acquisitions to date. Any impairment charge taken with respect to our long-lived assets or goodwill could be material and could have a material effect on NW Holdings or NW Naturals financial condition and results of operations. CUSTOMER CONSERVATION RISK. Customers conservation efforts may have a negative impact on NW Holdings and NW Naturals revenues. An increasing national focus on energy conservation, including improved building practices and appliance efficiencies may result in increased energy conservation by customers. This can decrease NW Naturals sales of natural gas and adversely affect NW Holdings or NW Naturals results of operations because revenues are collected mostly through volumetric rates, based on the amount of gas sold. In Oregon, NW Natural has a conservation tariff which is designed to recover lost utility margin due to declines in residential and small commercial customers consumption. However, NW Natural does not have a conservation tariff in Washington that provides it this margin protection on sales to customers in that state. Similar conservation risks exist for water utilities. Customers conservation efforts may have a negative impact on NW Holdings' and NW Naturals financial condition, revenues and results of operations. WEATHER RISK. Warmer than average weather may have a negative impact on our revenues and results of operations. We are exposed to weather risk in our natural gas business, primarily at NW Natural. A majority of NW Naturals gas volume is driven by gas sales to space heating residential and small commercial customers during the winter heating season. Current NW Natural rates are based on an assumption of average weather. Warmer than average weather typically results in lower gas sales. Colder weather typically results in higher gas sales. Although the effects of warmer or colder weather on utility margin in Oregon are expected to be mitigated through the operation of NW Naturals weather normalization mechanism, weather variations from normal could adversely affect utility margin because NW Natural may be required to purchase more or less gas at spot rates, which may be higher or lower than the rates assumed in its PGA. Also, a portion of NW Naturals Oregon residential and commercial customers (usually less than 10%) have opted out of the weather normalization mechanism, and approximately 12% of its customers are located in Washington where it does not have a weather normalization mechanism. These effects could have an adverse effect on NW Holdings and NW Naturals financial condition, results of operations and cash flows. Water Business Risks WATER SECTOR BUSINESS. NW Holdings has entered the water sector through the acquisition of a number of water and wastewater companies. Water and wastewater businesses are subject to a number of risks in addition to the risks described above. Although the water businesses are not currently expected to materially contribute to the results of operations of NW Holdings, these businesses are subject to risks, in addition to those described above that could adversely affect their results of operations, including: contamination of water supplies, including water provided to customers with naturally occurring or human-made substances or other hazardous materials; interruptions in water supplies and service, natural disasters and droughts; insufficient water supplies, limitations on or disputes with respect to water rights or supplies, or the inability to secure water rights or supplies at a reasonable cost; disruptions to the wastewater collection and treatment process; reliance on third parties for water supplies and transportation of such water supplies; conservation efforts by customers; regulatory and legal requirements, including environmental, health and safety laws and regulations; operational risks, including customer and employee safety; the outcome of rate cases and other regulatory proceedings; and weather conditions. Significant losses, liabilities or impairments arising from these businesses may adversely affect NW Holdings' financial position or results of operations. INVESTMENT RISK. NW Holdings expectations with respect to the financial results of its investments in water operations are based on various assumptions and beliefs that may not prove accurate, resulting in failures or delays in achieving expected returns or performance. NW Holdings expansion into the water sector is an important component of its growth strategy. Although NW Holdings expects its water and wastewater utility operations will result in various benefits, including expanding customer bases, providing investment opportunities through infrastructure development and enhancing regulatory relationships within the local communities served, NW Holdings may not be able to realize these or other benefits. Achieving the anticipated benefits is subject to a number of uncertainties, including whether the businesses acquired can be operated in the manner intended and whether costs to finance the acquisitions and investments will be consistent with expectations, as well as whether investments in the water sector can reach scale in a reasonable period of time. Events outside of our control, including but not limited to regulatory changes or developments, could adversely affect our ability to realize the anticipated benefits from building NW Holdings water platform. The integration of newly acquired water businesses, particularly over a noncontiguous geographic regions, may be unpredictable, subject to delays or changed circumstances, and such businesses may not perform in accordance with our expectations. In addition, anticipated costs, level of managements attention and internal resources to achieve the integration of or operate the acquired businesses may differ significantly from our current estimates resulting in failures or delays in achieving expected returns or performance. If NW Holdings' expectations regarding the financial results of its investments in water operations prove to be inaccurate, it may adversely affect NW Holdings' financial position or results of operations. Non-Regulated RNG Risks INVESTMENT RISK. NW Holdings expectations with respect to the financial results of its investments in non-regulated RNG investments are based on various assumptions and beliefs that may not prove accurate, resulting in failures or delays in achieving expected returns. NW Holdings expansion into the non-regulated RNG business is an important component of its growth strategy. Although NW Holdings expects this expansion will result in various benefits, including providing cost-effective solutions to decarbonize the utility, commercial, industrial and transportation sectors, NW Holdings may not be able to realize these or other benefits. Achieving the anticipated benefits is subject to a number of uncertainties, including whether the investments can be made at an expected scale, whether the investments can be monetized in the manner intended, and whether costs to finance the investments will be consistent with expectations. Events outside of our control, including but not limited to market or regulatory changes or developments, could adversely affect our ability to realize the anticipated benefits from building NW Holdings non-regulated RNG platform. The establishment and growth of a non-regulated RNG business may be unpredictable, subject to uncertainties or changed circumstances, and such business may not perform in accordance with our expectations. In addition, anticipated costs, level of managements attention and internal resources to achieve the integration of the acquired investments may differ significantly from our current estimates resulting in failures or delays in achieving expected returns or performance. We could additionally experience unsuccessful business models; technological challenges; ineffective scalability or inability to achieve production volumes consistent with our expectations and marketing arrangements; construction delays or cost overruns; disputes with third party business partners; risks related to markets for RNG and its associated attributes (including changes in market regulation, behavior, or prices); the inability to receive expected tax or regulatory treatment; or unexpected operating costs. If NW Holdings' expectations regarding the financial results of its investments in non-regulated RNG prove to be inaccurate, it may adversely affect NW Holdings' financial position or results of operations.

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ITEM 1. BUSINESS ##TABLE_START OVERVIEW ##TABLE_END NorthWestern Energy - Delivering a Bright Future NorthWestern Corporation, doing business as NorthWestern Energy, provides essential energy infrastructure and valuable services that enrich lives and empower communities while serving as long-term partners to our customers and communities. We work to deliver safe, reliable, and innovative energy solutions that create value for customers, communities, employees, and investors. We do this by providing low-cost and reliable service performed by highly-adaptable and skilled employees. We provide electricity and / or natural gas to approximately 764,200 customers in Montana, South Dakota, Nebraska, and Yellowstone National Park. We have provided service in South Dakota and Nebraska since 1923 and in Montana since 2002. We manage our businesses by the nature of services provided, and operate principally in three business segments: electric utility operations; natural gas utility operations; and all other, which primarily consists of unallocated corporate costs. Our electric utility operations include the generation, purchase, transmission and distribution of electricity, and our natural gas utility operations include the production, purchase, transmission, storage, and distribution of natural gas. Our customer base consists of a mix of residential, commercial, and diversified industrial customers. Our electric and natural gas utility operations are not dependent on a single customer, or even a few customers, and the loss of any one or even a few of our largest customers is not reasonably likely to have a material adverse effect on our financial condition. Our utility operations are seasonal and weather patterns can have a material impact on operating performance. Consumption of electricity is often greater in the summer and winter months for cooling and heating, respectively. Because natural gas is used primarily for residential and commercial heating, the demand for this product depends heavily upon weather patterns throughout our service territory, and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Environmental, Social and Governance We are focused on meeting current energy infrastructure and service needs at a reasonable and fair cost for todays customers while ensuring the ability to meet the needs of tomorrows customers. Sustainability requires meeting economic, societal, and environmental objectives. As a provider of essential infrastructure and service, a sustainable enterprise is vital to our customers and communities, as well as to our investors and employees. Over the past 100 years, we have maintained our commitment to provide customers with reliable and affordable electric and natural gas services while also being good stewards of the environment. Over time, we have increased our environmental sustainability efforts and our access to carbon-free energy resources. In February 2022, we made a commitment to achieving Net-Zero by the year 2050 for Scope 1 and Scope 2 carbon and methane emissions. Our Scope 1 emissions are primarily from owned electric generation plants, fugitive emissions from our natural gas production, gathering, transmission and distribution systems and company owned transportation fleet. Our Scope 2 emissions are primarily from the electric and natural gas utilized to heat, cool and power our offices, warehouses and other facilities. We currently own a mix of clean and carbon-free energy resources balanced with traditional energy sources that are necessary for us to deliver affordable and reliable electricity to our customers 24/7. In 2022, approximately 55 percent of our retail needs originated from carbon-free resources, compared to approximately 39 percent (Source: U.S. Energy Information Administration, 2022 Annual Energy Review, Electricity Net Generation: Electric Power Sector) for the total U.S. electric power industry in 2021. While we added additional carbon-free resources in 2022, our total output from carbon-free resources decreased from 56 percent in 2021 to 55 percent in 2022 due to our fossil fuel resources being dispatched at a higher percentage than in 2021. We do not receive all of the related Renewable Energy Credits (RECs) from our contracted electric supply resources and periodically sell RECs produced by our own carbon-free energy resources. The owner of the RECs claims the renewable attributes of the energy. Our resource mix does not represent the actual energy delivered to our customers. Market purchases and sales fill the gap between resources and customer demand. We are a fully regulated provider of critical infrastructure and essential services. Therefore, our success in meeting our obligations to our customers and the communities we serve depends on public policy. We believe that policy makers in the states we serve are committed to reliable, adequate, and affordable service, and a strong customer focus. We support policies that enable investment in critical infrastructure and responsible stewardship. We believe that technological advancements, along with decreasing costs of carbon-free generation and the regionalization of intermittent generation, will significantly contribute to our goal of Net-Zero carbon emissions by 2050. The pace of transition to Net-Zero will depend on the timing of technological advancements, costs, and retirement of our existing coal fleet. In South Dakota and Montana, we develop an Integrated Resource Plan (IRP) every two and three years, respectively. These IRPs, which are presented to our state regulatory commissions, identify resource needs, known and expected risks, as well as key variables to be used in evaluating resources. We then undertake a transparent resource solicitation process, run by an independent third party, to evaluate the least cost resources that address key risks and needs identified by the IRP. All generation types have the opportunity to participate in our Request for Proposals (RFP). Therefore, the specific resources that will be acquired to meet future need are dependent upon our current and future IRPs and the RFP process, in conjunction with the actions of our regulators during the regulatory process.. For a more detailed description of our environmental, social, governance and sustainability activities, please visit our company website at https://www.northwesternenergy.com . References to our website in this report are provided as a convenience and do not constitute, and should not be viewed as, an incorporation by reference of the information contained on, or available through, the website. Therefore, such information should not be considered part of this report. ##TABLE_START MONTANA ELECTRIC OPERATIONS ##TABLE_ENDOur regulated electric utility business in Montana includes generation, transmission and distribution. Our service territory covers approximately 107,600 square miles, representing approximately 73 percent of Montana's land area. During 2022, we delivered electricity to approximately 398,200 customers in 221 communities and their surrounding rural areas, 11 rural electric cooperatives and, in Wyoming, to the Yellowstone National Park. In 2022, by category, residential, commercial, industrial, and other sales accounted for approximately 45%, 46%, 5%, and 4%, respectively, of our Montana retail electric utility revenue. Transmission and Distribution Our electric system is composed of high voltage transmission lines and low voltage distribution lines as follows: ##TABLE_START Electric Transmission Lines Miles of 500 kV 497 Miles of 230 kV 987 Miles of 161 kV 1,184 Miles of 115 kV and lower voltage 3,929 Total Miles of Electric Transmission Lines 6,597 Electric Distribution Lines Miles of overhead line 13,276 Miles of underground line 5,258 Total Miles of Electric Distribution Lines 18,534 Total Transmission and Distribution Substations 394 ##TABLE_ENDIn addition to delivering energy to distribution systems to serve customers, we also transmit electricity for nonregulated entities owning generation, and utilities, cooperatives, and power marketers serving the Montana electricity market. Our total control area peak demand reached a new all-time peak of approximately 2,073 MWs on December 22, 2022. Our control area average demand for 2022 was approximately 1,379 MWs per hour, with total energy delivered of more than 12.08 million MWHs. Our transmission system is directly interconnected with Avista Corporation; Idaho Power Company; PacifiCorp; the Bonneville Power Administration; WAPA; and Montana Alberta Tie Ltd. Such interconnections, coupled with transmission line capacity made available under agreements with some of the above entities, permit the interchange, purchase, and sale of power among all major electric systems in the west interconnecting with the winter-peaking northern and summer-peaking southern regions of the western power system. We provide wholesale transmission service and firm and non-firm transmission services for eligible transmission customers pursuant to our FERC Open Access Transmission Tariff. Electric Supply Our annual retail electric supply load requirements average approximately 750 MWs, with a peak load of approximately 1,250 MWs, and are supplied by owned and contracted resources and market purchases with multiple counterparties. Owned generation resources supplied approximately 65 percent of our retail load requirements for 2022. We expect that approximately 65 percent of our retail obligations will be met by owned generation resources in 2023. In addition, we have contracts with QFs totaling 469 MWs of nameplate capacity, including 87 MWs from waste petroleum coke and waste coal, 268 MWs from wind, 17 MWs from hydro, and 97 MWs from solar projects. We have several other long-term power purchase agreements including contracts for 135 MWs nameplate capacity from wind generation, 100 MWs from the British Columbia hydro system, 52 MWs of natural gas generation, and 21 MWs of seasonal base-load hydro supply. On average, our owned and long-term contracted resources are expected to provide enough energy to meet our retail energy load requirements in 2023. Load requirements during peak demand in excess of our owned and long-term contracted resources will be satisfied with market purchases. Owned Generation Facilities Details of these generating facilities are described in the following tables. ##TABLE_START Hydro Facilities COD River Source FERC License Expiration Owned MW Black Eagle 1927 Missouri 2040 23 Cochrane 1958 Missouri 2040 62 Hauser 1911 Missouri 2040 21 Holter 1918 Missouri 2040 50 Madison 1906 Madison 2040 12 Morony 1930 Missouri 2040 49 Mystic 1925 West Rosebud Creek 2050 12 Rainbow 1910/2013 Missouri 2040 64 Ryan 1915 Missouri 2040 72 Thompson Falls 1915/1995 Clark Fork 2025 94 Total (1) 459 ##TABLE_END(1) The Hebgen facility (0 MW net capacity) is excluded from the figures above. These are run-of-river dams except for Mystic, which is storage generation. ##TABLE_START Other Facilities Fuel Source Ownership Interest Owned MW Colstrip Unit 4, located near Colstrip in southeastern Montana Sub-bituminous coal 30% 222 DGGS, located near Anaconda, Montana Natural Gas Liquid Fuel 100% 150 Spion Kop Wind, located in Judith Basin County in Montana Wind 100% 40 Two Dot Wind, located in Wheatland County in Montana Wind 100% 11 ##TABLE_ENDColstrip Unit 4 provides base-load supply and is operated by Talen Montana, LLC (Talen). Talen has a 30 percent ownership interest in Colstrip Unit 3. We have a reciprocal sharing agreement with Talen regarding the operation of Colstrip Units 3 and 4, in which each party receives 15 percent of the respective combined output and is responsible for 15 percent of the respective operating and construction costs, regardless of whether a particular cost is specified to

Colstrip Unit 3 or 4. However, each party is responsible for its own fuel-related costs. Colstrip Unit 4 is supplied with fuel from adjacent coal reserves under a coal supply agreement in effect through 2025. See Item 1A Risk Factors "Regulatory, Legislative and Legal Risks" for further discussion regarding the service life of generation facilities. Resource Planning Resource planning is an important function necessary to meet our customers' future energy needs and is used to guide resource acquisition activities. We filed our latest IRP with the MPSC in August 2019 and supplemented that plan in December 2020. Both filings projected generation capacity deficits and negative reserve margins. Since that time, we have been working to address the deficit with a combination of owned resources and long-term capacity contracts as well as short-and-intermediate term capacity contracts. We expect to file an updated IRP during the first quarter of 2023. We issued an all-source competitive solicitation request in January 2020 for peaking and flexible capacity to be available for commercial operation beginning in 2023. The competitive solicitation resulted in a 100 MW, 5-year purchase of capacity from a market participant and the development of the 175 MW Yellowstone County Generating Station, which is currently under construction. In addition to our responsibility to meet peak demand, national NERC reliability standards increased the need for us to have greater dispatchable generation capacity available and be capable of increasing or decreasing output to address intermittent generation such as wind and solar. Our generation portfolio is a balanced mix of energy and capacity resources having different operating characteristics and fuel sources designed to provide energy at the lowest possible cost to meet our obligation to serve retail customers while maintaining reliability. Western Energy Imbalance Market We entered the Western Energy Imbalance Market (EIM), operated by the California Independent System Operator, on June 16, 2021. We added EIM transfer capability with Bonneville Power Administration, Avista Corp, and Tacoma Power in 2022, in addition to our existing EIM transfer capability with PacifiCorp and Idaho Power Company. ##TABLE_START SOUTH DAKOTA ELECTRIC OPERATIONS ##TABLE_ENDOur South Dakota electric utility business operates as a vertically integrated generation, transmission and distribution utility. We have the exclusive right to serve an area in South Dakota comprised of 25 counties. We provide retail electricity to more than 64,700 customers in 116 communities in South Dakota. In 2022, by category, residential, commercial and other sales accounted for approximately 38%, 60%, and 2%, respectively, of our South Dakota retail electric utility revenue. Transmission and Distribution Our electric system includes high voltage transmission and low voltage distribution lines as follows: ##TABLE_START Electric Transmission Lines Miles of 345 kV 25 Miles of 230 kV 18 Miles of 115 kV and lower voltages 1,265 Total Miles of Electric Transmission Lines 1,308 Electric Distribution Lines Miles of overhead line 1,619 Miles of underground line 723 Total Miles of Electric Distribution Lines 2,342 Total Transmission and Distribution Substations 121 ##TABLE_END Our South Dakota system is interconnected with the transmission facilities of Otter Tail Power Company; Montana-Dakota Utilities Co.; Xcel Energy Inc.; and WAPA. We also have emergency interconnections with the transmission facilities of East River Electric Cooperative, Inc. and West Central Electric Cooperative. We are a transmission-owning member in the SPP, with our transmission facilities residing in zone 19 of the SPP footprint. Each year, we review all new or modified transmission assets and transfer functional control of assets that qualify under the SPP Tariff to the SPP. This annual update goes into effect on April 1 st each year. To date, we have transferred control of 333 line miles of 115 kV facilities and over 158 line miles of 69 kV facilities. Along with SPP, our South Dakota facilities have ties to MISO. We have grandfathered agreements in MISO, which provide us the access to move the power from the Coyote, Big Stone, and Neal power plants to our customers. Along with operating the transmission system, SPP also coordinates regional transmission planning for all of its members on an annual basis through its Integrated Transmission Planning (ITP) process. Our annual participation in the ITP process includes model development, system needs assessment, and solution development to address identified needs. Electric Supply Our annual retail electric supply load requirements average approximately 200 MWs, with a peak load of 340 MWs, and are supplied by owned and contracted resources and market purchases. We use market purchases and peaking generation to provide peak supply in excess of our base-load capacity. We are a member of the SPP. As a market participant in SPP, we buy and sell wholesale energy and reserves in both day-ahead and real-time markets through the operation of a single, consolidated SPP balancing authority. We and other SPP members submit into the SPP market both offers to sell our generation and bids to purchase power to serve our load. SPP optimizes next-day and real-time generation dispatch across the region and provides participants with greater access to economic energy. Marketing activities in SPP are handled for us by a third-party provider acting as our agent. Electric supply resources include 211 MWs from jointly owned coal plants and 138 MWs from two natural gas-fired plants. Additional resources include several peaking units and an 80 MW wind facility. We also purchase the output of four wind projects, three of which are QFs, under power purchase agreements. Actual output for our wind resources varies based upon weather conditions. Owned Generation Facilities Details of our generating facilities are described further in the following chart: ##TABLE_START Generation Facilities Fuel Source Ownership Interest Owned MW Big Stone Plant, located near Big Stone City in northeastern South Dakota Sub-bituminous coal 23.4% 111 Aberdeen Generating Units No. 1 and 2, located near Aberdeen, South Dakota Natural gas Liquid Fuel 100.0% 80 Beethoven Wind Project, located near Tripp, South Dakota Wind 100.0% 80 Bob Glanzer Generating Station, located near Huron, South Dakota Natural Gas 100.0% 58 Neal Electric Generating Unit No. 4, located near Sioux City, Iowa Sub-bituminous coal 8.7% 57 Coyote Electric Generating Station, located near Beulah, North Dakota Lignite coal 10.0% 43 Miscellaneous combustion turbine units and small diesel units (used only during peak periods) Combination of fuel oil and natural gas 100.0% 17 Total 446 ##TABLE_ENDWe completed the construction of the 58 MW Bob Glanzer Generating Station in the summer of 2022. This plant includes flexible reciprocating internal combustion engines near Huron, South Dakota. The Big Stone, Coyote and Neal plants are owned jointly with unaffiliated parties. Each of the jointly owned plants is subject to a joint management structure, and we are not the operator of any of these plants. Based on our ownership interest, we are entitled to a proportionate share of the capacity of our jointly owned plants and are responsible for a proportionate share of the operating costs. The fuel for our jointly owned base-load generating plants is provided through supply contracts of various lengths with several coal companies. Coyote is a mine-mouth generating facility. Neal Unit No. 4 and Big Stone receive their fuel supply via rail. The average delivered cost by type of fuel burned varies between generation facilities due to differences in transportation costs and owner purchasing power for coal supply. Changes in our fuel costs are passed on to customers through the operation of the fuel adjustment clause in our South Dakota tariffs. Resource Planning We have a resource plan that includes estimates of customer usage and programs to provide for the economic, reliable and timely supply of energy. We continue to update our load forecast to identify the future electric energy needs of our customers, and we evaluate additional generating capacity requirements on an ongoing basis. We submitted a plan to the SDPUC in September of 2022 to provide for the modernization of our generating fleet, which is focused on improving reliability and flexibility. ##TABLE_START NATURAL GAS OPERATIONS ##TABLE_ENDMontana Our regulated natural gas utility business in Montana includes production, storage, transmission and distribution. During 2022, we distributed natural gas to approximately 209,100 customers in 118 Montana communities over a system that consists of approximately 5,100 miles of underground distribution pipelines. We also serve several smaller distribution companies that provide service to approximately 37,000 customers. We transmit natural gas in Montana from production receipt points and storage facilities to distribution points and other nonaffiliated transmission systems. We transported natural gas volumes of approximately 47 Bcf during the year ended December 31, 2022. ##TABLE_START Miles of Natural Gas Transmission 2,235 Miles of Natural Gas Distribution 5,099 City Gate Stations 135 ##TABLE_ENDWe have connections in Montana with four major, unaffiliated transmission systems: Williston Basin Interstate Pipeline, NOVA Gas Transmission Ltd., Colorado Interstate Gas, and Spur Energy. Twelve compressor sites provide more than 46,000 horsepower on the transmission line and an additional 15,000 horsepower at our storage fields, capable of moving more than 360,000 dekatherms per day. In addition, we own and operate two transmission pipelines through our subsidiaries, Canadian-Montana Pipe Line Corporation and Havre Pipeline Company, LLC. Natural gas is used primarily for residential and commercial heating, and as fuel for two electric generating facilities. The demand for natural gas largely depends upon weather conditions. Our Montana retail natural gas supply requirements for the year ended December 31, 2022, were approximately 23.2 Bcf. Our Montana natural gas supply requirements for electric generation fuel for the year ended December 31, 2022, were approximately 5.7 Bcf. We have contracted with several major producers and marketers with varying contract durations to provide the anticipated supply to meet ongoing requirements. Our natural gas supply requirements are fulfilled through third-party fixed-term purchase contracts, short-term market purchases and owned production. Our portfolio approach to natural gas supply is intended to enable us to maintain a diversified supply of natural gas sufficient to meet our supply requirements. We benefit from direct access to suppliers in significant natural gas producing regions in the United States, primarily the Rocky Mountains (Colorado), Montana, and Alberta, Canada. Owned Production and Storage - Since 2010, we have acquired gas production and gathering system assets as a part of an overall strategy to provide rate stability and customer value: as we own these assets, which are regulated, our customers are protected from potential price spikes in the market. As of December 31, 2022, these owned reserves totaled approximately 35.1 Bcf and are estimated to provide approximately 3.0 Bcf in 2023, or approximately 13 percent of our expected annual retail natural gas load in Montana. In addition, we own and operate three working natural gas storage fields in Montana with aggregate working gas capacity of approximately 17.85 Bcf and maximum aggregate daily deliverability of approximately 194,000 dekatherms. South Dakota and Nebraska We provide natural gas to approximately 49,200 customers in 80 South Dakota communities and approximately 43,000 customers in 4 Nebraska communities. In South Dakota, we also transport natural gas for nine gas-marketing firms and three large end-user accounts. In Nebraska, we transport natural gas for four gas-marketing firms and one large end-user account. We delivered approximately 31.0 Bcf of third-party transportation volume on our South Dakota distribution system and approximately 3.8 Bcf of third-party transportation volume on our Nebraska distribution system during 2022. ##TABLE_START Miles of Natural Gas Transmission 55 Miles of Natural Gas Distribution 2,545 ##TABLE_ENDOur South Dakota natural gas supply requirements for the year ended December 31, 2022, were approximately 6.3 Bcf. We contract with a third party under an asset management agreement to manage transportation and storage of supply to minimize cost and price volatility to our customers. In Nebraska, our natural gas supply requirements for the year ended December 31, 2022, were approximately 4.4 Bcf. We contract with a third party under an asset management agreement that includes pipeline capacity, supply, and asset optimization activities. To supplement firm gas supplies in South Dakota and Nebraska, we contract for firm natural gas storage services to meet the heating season and peak day requirements of our customers. Municipal Natural Gas Franchise Agreements We have municipal franchises to provide natural gas service in the communities we serve. The terms of the franchises vary by community. Our Montana franchises typically have a fixed 10-year term and continue for additional 10-year terms unless and until canceled, with 5 years notice. The maximum term permitted under Nebraska law for these franchises is 25 years while the maximum term permitted under South Dakota law is 20 years. Our policy generally is to seek renewal or extension of a franchise in the last year of its term. We continue to serve those customers while we obtain formal renewals. During the next five years, nine of our Montana franchises could expire by action taken by the franchises' city or town, which account for approximately 9,077 or four percent of our Montana natural gas customers. Six of our South Dakota franchises and one franchise in Nebraska, which account for approximately 27,104 or 29 percent of our South Dakota and Nebraska natural gas customers, are scheduled to reach the end of their fixed term during the next five years. We do not anticipate termination of any of these franchises. ##TABLE_START GOVERNMENT REGULATION ##TABLE_ENDNorthWesterns provision of utility service is regulated by the MPSC, the SDPUC, the NPSC, and the FERC. NorthWestern is also regulated by many other state and federal agencies. For example, because NorthWesterns operations impact land, waterways and the air, NorthWestern is subject to a wide range of regulations administered by the federal Environmental Protection Agency, the U.S. Fish Wildlife Service, and parallel state agencies regulating environmental and natural resources in Montana, South Dakota and Nebraska. Another example relates to NorthWesterns provision of natural gas service. The U.S. Department of Transportation through the Pipeline and Hazardous Materials Safety Administration, along with its state partners, regulates natural gas pipeline and natural gas storage field safety. As a publicly-traded company, we are subject to the SECs requirements regarding financial reporting, disclosures, and laws and regulations protecting investors. We are subject to the Occupational Safety and Health Administration (OSHA), which regulates workplace safety. We are also subject to local zoning laws and regulations. As detailed below, the rates we charge our utility customers are set through approval by the regulatory commission with jurisdiction in each of our respective service territories. Base rates are the rates that are intended to allow us the opportunity to collect from our customers total revenues (revenue requirements) equal to our cost of providing delivery and rate-based supply services, plus a reasonable rate of return on invested capital. We have both electric and natural gas base rates and cost tracking clauses. We may ask the respective regulatory commission to increase base rates from time to time. Rate increase requests are normally reviewed based on historical data and any resulting approvals may not always keep pace with increasing costs. For more information on current regulatory matters, see Note 3 - Regulatory Matters , to the Consolidated Financial Statements. The following is a summary of our rate base (amounts we earn a return on) and authorized rates of return in each jurisdiction, estimated as of December 31, 2022: ##TABLE_START Jurisdiction and Service Implementation Date Authorized Rate Base (millions) Year-end Estimated Rate Base (millions) Authorized Overall Rate of Return Authorized Return on Equity Authorized Equity Level Montana electric delivery and production (1) April 2019 (4) $2,030.1 $2,675.8 6.92% 9.65% 49.38% Montana - Colstrip Unit 4 April 2019 304.0 271.3 8.25% 10.00% 50.00% Montana natural gas delivery and production (2) September 2017 (4) 430.2 643.3 6.96% 9.55% 46.79% Total Montana $2,764.3 $3,590.4 South Dakota electric (3) December 2015 $557.3 $799.6 7.24% n/a n/a South Dakota natural gas (3) December 2011 65.9 97.8 7.80% n/a n/a Total South Dakota $623.2 $897.4 Nebraska natural gas (3) December 2007 $24.3 $49.9 8.49% 10.40% n/a $3,411.8 $4,537.7 ##TABLE_END(1) The revenue requirement associated with the FERC regulated portion of Montana electric transmission and ancillary services are included as revenue credits to our MPSC jurisdictional customers. Therefore, we do not separately reflect FERC authorized rate base or authorized returns. (2) The Montana gas revenue requirement includes a step down which approximates annual depletion of our natural gas production assets included in rate base. (3) For those items marked as "n/a," the respective settlement and/or order was not specific as to these terms. (4) On August 8, 2022, we filed a Montana electric and natural gas rate review filing (2021 test year) requesting an increase to our authorized rate base, return on equity, and equity level in our capital structure. We expect a final order regarding this rate review in 2023. MPSC Regulation Our Montana operations are subject to the jurisdiction of the MPSC with respect to rates, terms and conditions of service, accounting records, electric service territorial issues and other aspects of our operations, including when we issue, assume, or guarantee securities in Montana, or when we create liens on our regulated Montana properties. We have an obligation to provide service to our customers with an opportunity to earn a regulated rate of return. Electric Supply Tracking Mechanism - The Power Cost and Credit Adjustment Mechanism (PCCAM) tracks, for recovery through utility rates, the cost of power purchased and fuel used to generate electricity. The PCCAM incorporates sharing of a portion of the business risk or benefit associated with the energy supply costs with 90 percent of the variance above or below the established base revenues and actual costs collected from or refunded to customers. Customer prices may be adjusted annually to absorb the difference for the annual tracking period. Annual filings are based on a July through June 12-month tracking period, and are subject to review by the MPSC to determine if electric supply procurement activities were prudent. If the MPSC subsequently determines that a procurement activity was imprudent, recovery of such costs may be disallowed. Natural Gas Supply Tracker - Rates for our Montana natural gas supply are set by the MPSC. Certain supply rates are adjusted on a monthly basis for volumes and costs during each July to June 12-month tracking period based on the established base revenues and actual costs collected from customers or refunded to customers. Customer prices may be adjusted annually to absorb the difference for the annual tracking period. Annual filings are based on a July through June 12-month tracking period, and are subject to review by the MPSC to determine if natural gas supply procurement activities were prudent. If the MPSC subsequently determines that a procurement activity was imprudent, recovery of such costs may be disallowed. Montana Property Tax Tracker - We file an annual property tax tracker (including other state/local taxes and fees) with the MPSC for an automatic rate adjustment, which reflects the incremental property taxes since our last base rate filing adjusted for the associated income tax benefit. Fixed Cost Recovery Mechanism Pilot - In our 2018 Montana electric rate settlement, the MPSC approved a Fixed Cost Recovery Mechanism Pilot (FCRM), intended to decouple our recovery of fixed, test-year based transmission, distribution, and production costs from sales of energy. At our request, the MPSC delayed implementation of the pilot until modifications are considered in our pending 2022 Montana electric and natural gas rate review filing. SDPUC Regulation Our South Dakota operations are subject to SDPUC jurisdiction with respect to rates, terms and conditions of service, accounting records, electric service territorial issues and other aspects of our electric and natural gas operations. Our retail electric rates, approved by the SDPUC, provide several options for residential, commercial and industrial customers, including dual-fuel, interruptible, special all-electric heating, and other special rates. Our retail natural gas tariffs include gas transportation rates for transportation through our distribution systems by customers and natural gas marketers from the interstate pipelines at which our systems take delivery to the end-user. Such transporting customers nominate the amount of natural gas to be delivered daily. On a daily basis, we monitor usage for these customers and balance it against their respective supply agreements. An electric adjustment clause provides for quarterly adjustment based on differences in the delivered cost of energy, delivered cost of fuel, ad valorem taxes paid and commission-approved fuel incentives. The adjustment goes into effect upon filing, and is deemed approved within 10 days after the information filing unless the SDPUC staff requests changes during that period. A purchased gas adjustment provision in our natural gas rate schedules permits the monthly adjustment of charges to customers to reflect increases or decreases in purchased gas, gas transportation and ad valorem taxes. NPSC Regulation Our Nebraska natural gas rates and terms and conditions of service for residential and smaller commercial customers are regulated by the NPSC. High volume customers are not subject to such regulation, but can file complaints if they allege discriminatory treatment. Under the Nebraska State Natural Gas Regulation Act, a regulated natural gas utility may propose a change in rates to its regulated customers, if it files an application for a rate increase with the NPSC and with the communities in which it serves customers. The utility may negotiate with those communities for a settlement with regard to the proposed rate change if the affected communities representing more than 50 percent of the affected ratepayers agree to direct negotiations, or it may proceed to have the NPSC review the filing and make a determination. Our tariffs have been approved by the NPSC, and the NPSC has adopted certain rules governing the terms and conditions of service of regulated natural gas utilities. Our retail natural gas tariffs provide residential, general service and commercial and industrial options, as well as firm and interruptible transportation service. A purchased gas adjustment clause provides for biannual, or more often if needed, adjustments based on changes in gas supply and interstate pipeline transportation costs. FERC Regulation We are subject to FERC's jurisdiction and regulations with respect to rates for electric transmission service and electricity sold at wholesale, hydro licensing and operations, the issuance of certain securities, incurrence of certain long-term debt, and compliance with mandatory reliability standards, among other things. Under FERC's open access transmission policy, as owners of transmission facilities, we are required to provide open access to our transmission facilities under filed tariffs at cost-based rates. In addition, we are required to comply with FERC's Standards of Conduct for Transmission Providers. Our

Montana wholesale transmission customers, such as cooperatives, industrial customers, and other customers that have third-party commodity supply providers, are served under our OATT, which is on file with FERC. The OATT defines the terms, conditions, and rates of our Montana transmission service, including ancillary services. Our South Dakota transmission operations are in the SPP, and transmission service is provided under the SPP OATT. Our natural gas transportation pipelines are generally not subject to FERC's jurisdiction, although we are subject to state regulation. We conduct limited interstate transportation in Montana and South Dakota that is subject to FERC jurisdiction, and FERC has allowed the MPSC and SDPUC to set the rates for this interstate service. We have capacity agreements in South Dakota and Nebraska with interstate pipelines that are also subject to FERC jurisdiction. Our hydroelectric generating facilities are licensed by the FERC and operated under the terms of those licenses and FERC regulations. In connection with the relicensing of these generating facilities, applicable law permits the FERC to issue a new license to the existing licensee, to a new licensee, or alternatively allows the U.S. government to take over the facility. If the existing licensee is not relicensed, it is compensated for its net investment in the facility, not to exceed the fair value of the property taken, plus reasonable severance damages to other property affected by the lack of relicensing. Reliability Standards - We must comply with the standards and requirements that apply to the NERC functions for which we have registered in both the MRO for our South Dakota operations and the WECC for our Montana operations. WECC and the MRO have responsibility for monitoring and enforcing compliance with the FERC-approved mandatory reliability standards within their respective regions. We expect that the reliability standards will continue to evolve and change as a result of modifications, guidance, and clarification following industry implementation and ongoing audits and enforcement. ##TABLE_START COMPETITION ##TABLE_ENDWe are subject to public policies that promote competition and development of energy markets. Our industrial and large commercial customers have the ability to choose their electric supplier and may generate their own electricity. In addition, customers may have the option of substituting other fuels or relocating their facilities to a lower cost region. Customers have the opportunity to supply their own power with distributed generation including solar generation, and in Montana, can currently avoid paying for most of the fixed production, transmission and distribution costs incurred to serve them. These incentives and federal tax subsidies make distributed generating resources viable potential competitors to our electric service business. In addition, the FERC has continued to promote competitive wholesale markets through open access transmission and other means. Our wholesale customers can purchase their output from generation resources of competing suppliers or non-contracted quantities and use the transmission systems to serve their load. There is also competition for available transmission capacity to meet our electric supply needs to serve customers. ##TABLE_START ENVIRONMENTAL ##TABLE_ENDThe operation of electric generating, transmission and distribution facilities, and gas gathering, storage, transportation and distribution facilities, along with the development (involving site selection, environmental assessments, and permitting) and construction of these assets, are subject to extensive federal, state, and local environmental and land use laws and regulations. Our activities involve compliance with diverse laws and regulations that address emissions and impacts to the environment, including air and water, and protection of natural resources and wildlife. We monitor federal, state, and local environmental initiatives to determine potential impacts on our financial results. As new laws or regulations are issued, we assess their applicability and implement the necessary modifications to our facilities or their operation to maintain ongoing compliance. To this end, the Biden Administration set ambitious goals to address climate change, including the goal of a carbon free power sector by 2035 and net zero carbon emissions by 2050. Executive Orders issued by the Biden Administration included initiatives and directives intended to reduce greenhouse gas (GHG) emissions, address climate change and decarbonize the energy sector. These Executive Orders established climate considerations as key components of United States foreign policy and national security, established a White House Office of Domestic Climate policy as well as a National Climate Task Force, called for agency heads to identify any fossil fuel subsidies provided by their agencies and to take steps to ensure that federal funding is not directly subsidizing fossil fuels, and directed agencies to immediately review all regulations proposed or finalized by the Trump Administration that conflict with the Biden Administrations objectives and to take action to rescind or revise those rules. Months later, President Biden officially rejoined the Paris Accord. More recently, President Biden's Infrastructure Investment and Jobs Act and Inflation Reduction Act of 2022 contain significant climate initiatives. These initiatives present opportunities for federal grants and tax incentives intended to hasten the future economy-wide deployment of various GHG reducing technologies and approaches. Implementation of these initiatives and directives has the potential to limit or curtail our operations, including the burning of fossil fuels at our coal-fired power plants. While we strive to comply with all environmental regulations applicable to our operations, it is not possible to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to energy and environmental laws and regulations, or new administrative or judicial interpretations or enforcement decisions regarding them. Estimated capital expenditures for environmental control facilities in 2023 and 2024 are not expected to be material. For more information on environmental regulations and contingencies and related capital expenditures, s e e Note 18 - Commitments and Contingencies , to the Consolidated Financial Statements. ##TABLE_START CORPORATE INFORMATION AND WEBSITE ##TABLE_ENDWe were incorporated in Delaware in November 1923. Our Internet address is https://www.northwesternenergy.com . Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports, along with our annual report to shareholders and other information related to us, are available, free of charge, on our Internet website as soon as reasonably practicable after we electronically file those documents with, or otherwise furnish them to, the SEC. This information is available in print to any shareholder who requests it. Requests should be directed to: Investor Relations, NorthWestern Corporation, 3010 W. 69th Street, Sioux Falls, South Dakota 57108 and our telephone number is (605) 978-2900. References to our website in this report are provided as a convenience and do not constitute, and should not be viewed as, an incorporation by reference of the information contained on, or available through, the website. Therefore, such information should not be considered part of this report. ##TABLE_START HUMAN CAPITAL RESOURCES ##TABLE_ENDOur ability to achieve the objectives of our business strategy and serve our customers within our service territory depends on employing skilled individuals at all levels of our organization. We aspire to be an employer of choice by offering competitive salaries and benefits, providing a safe working environment, valuing diversity, fostering inclusion and encouraging a healthful worklife balance. Our success comes when employees feel empowered to take initiative, voice their opinions, and build on their experiences within our company and our communities. As of December 31, 2022, we had 1,530 employees. Of these, 1,232 employees were in Montana and 298 were in South Dakota or Nebraska. Of our Montana employees, 454, or 37 percent, were covered by seven collective bargaining agreements involving five unions. During 2022, all seven collective bargaining agreements were renegotiated and a 4-year ratified agreement was reached. Each of the Montana collective bargaining agreements will now expire in 2026. Of our South Dakota and Nebraska employees, 165, or 56 percent, are covered by a collective bargaining agreement renegotiated in 2021 that expires in 2025. We consider our relations with employees to be good. Talent Management Attraction and retention of skilled employees is key to our ongoing success. We invest resources in maintaining a culture that supports the ongoing development of our workforce. This includes an integrated learning and performance management system which includes annual performance reviews that link goals and competencies together so that managers are able to provide a holistic view to employees in regards to their performance against goals as well as key competencies as they relate to their role in the organization. This process provides opportunities to develop and enhance skills and knowledge, and enables our employees to grow professionally and perform their duties in a safe and efficient manner. This structured training and development is intended to provide employees a consistent learning experience, and maximizes learning retention and background knowledge. We offer tuition reimbursement to promote continued professional growth for current employees, and a scholarship program for students attending universities, colleges, and technical schools in our service area to assist in developing current and future skills sets needed by our employees. We support annual pre-apprentice scholarships, recruit and hire suitable candidates from the program, serve as industry advisors on the program board and have donated training assets to support the program. Compensation and Benefits Our overarching compensation philosophy is structured to be consistent with our peers, and to align the long term interests of our employees, executives, shareholders, and customers so the pay appropriately reflects performance in achieving financial and non-financial operating objectives. We offer a competitive pay and benefits package, which is benchmarked on an annual basis to external market data. Beyond base pay and incentive compensation, we offer competitive, cost-effective, and well-rounded benefits, which aligns with our desire to be an employer of choice. From considerable employer retirement contributions, to generous paid time off (PTO), to health care and well-being programs, our benefits are designed to meet the varied needs of our employees. We are committed to internal pay equity, and the Human Resources Committee of the Board of Directors monitors the relationship between the pay our executive officers receive and the pay our non-managerial employees receive. During 2022 and 2021, the compensation for our CEO was approximately 26 and 28 times, respectively, the compensation of our median employee. We believe that a significant portion of an executives pay should be at risk in the form of performance-based incentive awards that are only paid if the individual and company performance targets are met. For 2022, approximately 79 percent of the targeted compensation of our CEO and about 65 percent of the targeted compensation of our other named executive officers is at risk in the form of performance-based incentive awards or time-based awards tied to the value of equity. Our Board of Directors establishes the metrics and targets for these incentive awards, based upon advice from the Board of Directors independent compensation consultant. We engage nationally recognized outside compensation and benefits consulting firms to independently evaluate the effectiveness of our compensation and benefits programs and to provide benchmarking against our peers within the industry. Diversity We believe a diverse and inclusive workforce adds value and helps us succeed in an ever-changing environment. By embracing diversity and fostering inclusion, we aim to enable each employee, executive, and director to contribute fully to the company. We believe diversity is important because varied perspectives expand our ability to bring unique professional experiences to our business. Diversity in the workforce will be considered when relevant to hiring, promotions, work assignments, or other decisions related to the terms and conditions of employment. Our workforce reflects the relative diversity of our available talent in the communities we serve. Our employment data is tested annually by a third party as part of our Affirmative Action plan development to identify any needed corrective placement goals that are required. This testing determined that there is no current need to establish corrective placement goals in our plan. We continue to maintain a diverse workforce, with an executive team that is 50% female and a board of directors that is 38% female and has one ethnically diverse member (13%). In addition, the equitable nature of our compensation practices has led to a low CEO to median employee ratio of 26 to 1. We have implemented methods to provide pay equity between our female and male employees performing equal or substantially similar work. We have engaged with a third party to review our pay equity between our male and female employees, share the results with our Board of Directors, and take corrective action as necessary. Our most recent study was performed in 2019, with no corrective action required. Health and Safety As stewards of critical infrastructure, providers of energy service, and members of the communities we serve, our priority is the health and safety of our employees and customers. Safety and health are considered and integrated into all work activities. We monitor several different key areas relating to safety philosophies and policies. These key metrics include the recordable incident rate (number of work-related injuries per 100 employees for a one-year period) and lost time incident rate (number of employees who lost time due to work-related injuries per 100 employees for a one-year period). During the years ended December 31, 2022 and 2021, our recordable incident rates were 1.57 and 1.77 and lost time incident rates were 0.59 and 0.66 on a company wide basis. Our five-year average safety record for the year ended December 31, 2022 was better than our industry peer group's five-year average. ##TABLE_START INFORMATION ABOUT OUR EXECUTIVE OFFICERS ##TABLE_END##TABLE_START Executive Officer Current Title and Prior Employment Age (1) Brian B. Bird President and Chief Executive Officer and Director since January 2023; formerly President and Chief Operating Officer since February 2021 and Chief Financial Officer from December 2003 to February 2021. Mr. Bird also serves on the board of directors of a NorthWestern subsidiary. 60 Crystal D. Lail Vice President and Chief Financial Officer since February 2021; formerly Vice President and Chief Accounting Officer since April 2020; and formerly Vice President and Controller from October 2015 to April 2020. 44 Michael R. Cashell Vice President - Transmission since May 2011. Mr. Cashell serves on the board of directors of a NorthWestern subsidiary. 60 John D. Hines Vice President - Supply and Montana Government Affairs since January 2018; formerly Vice President - Supply since May 2011. 64 Curtis T. Pohl Vice President - Asset Management Business Development since September 2022; formerly Vice President - Distribution since May 2011. Mr. Pohl serves on the board of directors of a NorthWestern subsidiary. 58 Bobbi L. Schroeppel Vice President - Customer Care, Communications and Human Resources since May 2009. 54 Jeanne M. Vold Vice President - Technology since February 2021; formerly Business Technology Officer since 2012. 56 Jason C. Merkel Vice President - Distribution since September 2022; formerly General Manager - Operations and Construction since 2007. 55 Cyndee S. Fang Vice President - Regulatory Affairs since January 2023; formerly Director - Regulatory Affairs since March 2021; prior to joining the Company, she was Origination Portfolio Design Manager from December 2020 to March 2021, Manager of Energy Research Analysis from August 2018 to December 2020, and Manager of Customer Pricing from June 2017 to August 2018, in each case, for San Diego Gas and Electric Company, an electric and gas utility. 53 Shannon M. Heim Vice President - General Counsel and Federal Government Affairs since January 2023; formerly Director, Regulatory Corporate Counsel since June 2020; and formerly Equity Shareholder at the law firm of Moss Barnett, P.A. from 2017 to 2020. 50 ##TABLE_END(1) As of February 10, 2023. Officers are elected annually by, and hold office at the pleasure of the Board of Directors (Board), and do not serve a term of office as such. ITEM 1A. RISK FACTORS You should carefully consider the risk factors described below, as well as all other information available to you, before making an investment in our common stock or other securities. Although the risks are organized by heading, and each risk is described separately, many of the risks are interrelated. You should not interpret the disclosure of any risk factor to imply that the risk has not already materialized. While we believe we have identified and discussed below the key risk factors affecting our business, there may be additional risks and uncertainties that are not presently known or that are not currently believed to be significant that may adversely affect our business, financial condition, results of operations or cash flows in the future. ##TABLE_START Regulatory, Legislative and Legal Risks ##TABLE_END Our profitability depends on our ability to recover the costs of providing energy and utility services to our customers and earn a return on our capital investment in our utility operations. We are subject to potential unfavorable litigation, and state and federal regulatory outcomes. To the extent our incurred costs are deemed imprudent by the applicable regulatory commissions or certain regulatory mechanisms are not available, we may not recover some of our costs or collect them in a timely manner, which could adversely impact our results of operations and liquidity. We are subject to comprehensive regulation by federal and state utility regulatory agencies, including siting and construction of facilities, customer service and rates that we can charge customers. Rate regulation is premised on providing an opportunity to earn a reasonable rate of return on invested capital and rates are generally set through a process called a rate review (or rate case) in which the utility commission analyzes our costs incurred during a historical test year and decides whether they may be included in our base rates. In addition to formal general rate reviews, we also have cost tracking mechanisms that are intended to allow us to recover prudently incurred costs. There can be no assurance that the applicable regulatory commission will judge all of our costs to have been prudently incurred or that the regulatory process in which rates are determined will result in rates that allow us the opportunity to earn our authorized return or provide for timely and full recovery of such costs. In addition, each regulatory commission sets rates based in part upon their acceptance of an allocated share of total utility costs. When commissions adopt different methods to calculate inter-jurisdictional cost allocations, some costs may not be recovered. Differing schedules and regulatory practices between our state commissions and FERC expose us to the risk that we may not fully recover our costs due to timing of filings, specific calculations and issues such as cost allocation methodologies. Thus, the rates we are allowed to charge may or may not match our costs at any given time. Adverse regulatory rulings could have an adverse impact on our results of operations and materially affect our ability to meet our financial obligations, including debt payments and the payment of dividends on our common stock. Historically, in Montana we have often sought and received a determination from the MPSC that acquisitions or additions to our generating portfolio were pre-approved, with subsequent investment subject to a later prudence determination. The Montana preapproval statute is currently the subject of litigation. If the preapproval statute is not ultimately upheld, there will be no explicit statutory mechanism that facilitates advanced approval of generating resource selection. Without preapproval, we may be subject to additional risk of non-recovery, which can increase debt costs and rates paid by customers. We are also at risk of unfavorable litigation outcomes related to zoning and environmental permits. See discussion related to our Yellowstone County Generating Station below in Managements Discussion and Analysis Significant Trends and Regulation. Adverse litigation outcomes could delay or terminate projects, increase costs and impact our ability to service our customers. We are subject to changing federal and state laws and regulations. Congress and state legislatures may enact legislation that adversely affects our operations and financial results. We are subject to regulations under a wide variety of U.S. federal and state regulations and policies. Regulation affects almost every aspect of our business. Changes to federal and state laws and regulations are continuous and ongoing and the federal administration, the U.S. Congress, state legislatures and state administrations may enact and implement new laws and regulations that could adversely and materially affect us. For example, legislation and regulations may be enacted that require or facilitate alternative generation or storage which, in turn, could result in customers using less of our energy or facilities which could reduce our revenues and our growth opportunities. We cannot predict future changes in laws and regulations, how they will be implemented and interpreted, or the ultimate effect that this changing environment will have on us. There can be no assurance that laws, regulations and policies will not be changed in ways that have a material adverse effect on our operations, financial condition, results of operations, and cash flows. We are subject to extensive and changing energy, and environmental laws and regulations, including legislative, judicial, and regulatory responses to climate change, with which compliance may be difficult and costly. Our operations are subject to laws and regulations imposed by federal, state and local government authorities regarding energy policy, permitting/siting for energy projects, climate change, the environment, air and water quality, GHG emissions, protection of natural resources, migratory birds and other wildlife, solid waste disposal, coal ash and other environmental considerations. We believe that we are in compliance with environmental regulatory requirements. In response to recent regulatory and judicial decisions and international accords, GHG emissions, most significantly CO_2 , could be restricted in the future as a result of federal or state legal requirements or litigation relating to GHG emissions. No rules are currently in effect that require us to reduce our GHG emissions. However, laws and regulations to which we must adhere change, and the Biden Administrations agenda includes a significant shift in environmental and energy policy, focusing on reducing GHG emissions and addressing climate change issues. Together, these actions reflect climate change issues and GHG emissions as central areas of focus for domestic and international regulations, orders and policies. In addition, a parallel focus on reducing GHG emissions is reflected in legislation introduced in Congress. These initiatives could lead to new and revised energy and environmental laws and regulations, including tax reforms relating to energy and environmental issues. Any such changes, as well as any enforcement actions or judicial decisions regarding those laws and regulations, could result in significant additional compliance costs that would affect our future financial position, results of operations and cash flows if such costs are not recovered through regulated rates. Such changes also could affect the manner in which we conduct our business and could require us to make substantial additional capital expenditures or abandon certain projects. Although previous attempts by the EPA to regulate GHG emissions from coal-fired plants have not succeeded, if GHG and/or methane regulations are implemented, compliance with carbon dioxide (CO_2) emission performance standards, and with other future environmental rules, may make it economically impractical to continue operating all or a portion of our jointly owned facilities or for individual owners to participate in their proportionate ownership of the coal-fired generating units. This could lead to significant impacts to customer rates for recovery of plant improvements and / or closure related costs and costs to procure replacement power. In addition, these changes could impact system reliability due to changes in generation sources. To the extent that costs exceed our estimated environmental liabilities, or we are not successful in recovering remediation costs or costs to comply with the proposed or any future changes in rules or regulations, our results of operations and financial position could be adversely affected. Certain environmental laws and regulations also provide for substantial civil and criminal fines for noncompliance which, if imposed, could result in material costs or liabilities. In addition, there is a risk of environmental damage claims from private parties or government entities. We may be required to make significant expenditures in connection with the investigation and remediation of alleged or actual spills, personal injury or property damage claims, and the repair, upgrade or expansion of our facilities to meet future requirements and obligations under environmental laws. Early closure of our owned and jointly owned electric generating facilities due to environmental risks, litigation or public policy changes could have a material adverse impact on our results of operations and liquidity. While a majority of our Company-wide electric supply portfolio is carbon-free, it does include fossil-fuel resources. Environmental advocacy groups, certain investors and other third parties oppose the operation of fossil-fuel generation, expressing concerns about the environmental and climate-related impacts from fossil fuels. This opposition may increase in scope and frequency depending on a number of variables, including the course of Federal and State laws and environmental regulations and the financial resources devoted to opposition efforts. These risks include litigation against us due to GHG or other emissions or coal combustion residuals disposal and storage; activist shareholder proposals; and increased activism before our regulators. We cannot predict the effect that any such opposition may have on our ability to operate and recover the costs of our generating facilities. In addition, defense costs associated with litigation can be significant and an adverse outcome could require substantial capital expenditures and could possibly require payment of substantial penalties or damages. Such payments or expenditures could affect results of operations, financial condition or cash flows if such costs are not recovered through regulated rates. In particular, as described more fully below in Note 18 - Commitments and Contingencies , we are a co-owner of Colstrip Unit

4. The remaining depreciable life of our investment in Colstrip Unit 4 is through 2042. Talen and Puget Sound Energy (Puget), a co-owner of Colstrip, have entered into a transaction in which Puget will transfer its 25% project share in Units 3 and 4 to Talen. The anticipated closing date of the transaction is December 31, 2025. On September 12, 2022, Puget issued a notice of the transaction, triggering a 90 day timeframe in which we, or other co-owners could exercise rights of first refusal arising under the Ownership and Operation Agreement relating to these units (the OO Agreement). The co-owners subsequently agreed to extend the time to exercise rights of first refusal until February 22, 2023. On January 16, 2023 we entered into an agreement with Avista Corporation pursuant to which it will transfer to us its 15% project share in Units 3 and 4 on December 31, 2025. Each of the co-owners will have 90 days following Avista's February 17, 2023 notice under the OO Agreement, to exercise their rights of first refusal as to the Avista-NorthWestern transaction. The closure by third parties of Billings area generation (Corette) and Colstrip Units 1 and 2 reducing supply, together with increased customer load and the lack of dispatchable replacement generation in eastern Montana, has accelerated concerns about potential difficulties in physically serving parts of Montana including the Billings area. We are executing on multi-year plans for upgrades to the Billings area substations and other delivery infrastructure, but the addition of dispatchable generation in the area is also critical to reliable service in eastern Montana. Increased risks of regulatory penalties could negatively impact our business. We must comply with established reliability standards and requirements including Critical Infrastructure Protection Reliability Standards, which apply to North American Electric Reliability Corporation (NERC) functions. NERC reliability standards protect the nations bulk power system against potential disruptions from cyber and physical security breaches. The FERC, NERC, or a regional reliability organization may assess penalties against any responsible entity that violates their rules, regulations or standards. Penalties for the most severe violations can reach nearly $1.2 million per violation, per day. If a serious reliability incident or other incidence of noncompliance did occur, it could have a material adverse effect on our operating and financial results. Additionally, the Pipeline and Hazardous Materials Safety Administration, Occupational Safety and Health Administration and other federal or state agencies have penalty authority. In the event of serious incidents, these agencies have become more active in pursuing penalties. Some states have the authority to impose substantial penalties. If a serious reliability or safety incident did occur, it could have a material effect on our results of operations, financial condition or cash flows. Federally mandated purchases of power from QFs, and integration of power generated from those projects in our system, may increase costs to our customers and decrease system reliability, limit our ability to make generation investments and adversely affect our business. We are generally obligated under federal law to purchase power from certain QF projects, regardless of current load demand, availability of lower cost generation resources, transmission availability or market prices. Although some of these resources include a battery component, they are primarily intermittent generation whose prices may be in

excess of market prices during times of lower customer demand, and may not be able to generate electricity during peak times. These resources typically do not meet the requirements set forth in our supply plans for resource procurement. These requirements to purchase supply that is inconsistent with customer need may have multiple impacts, including increasing the likelihood and frequency that we will be required to reduce output from owned generation resources, negatively impacting our ability to make our own generation investments and increasing the likelihood that we will need to upgrade or build additional transmission facilities to serve QF projects. Any of these results would increase costs to customers and impact our investment plan. Further, balancing load and power generation on our system is challenging, and we expect that operational costs will increase as a result of integration of these intermittent, non-dispatchable generation projects. If we are unable to timely recover those costs, those increased costs may negatively affect our liquidity, results of operations and financial condition. In addition, requirements to procure power from these sources could impact our ability to make generation investments depending upon the number and size of QF contracts we ultimately enter into. The cost to procure power from these QFs may not be a cost effective resource for customers, or the type of generation resource needed, resulting in increased supply costs that are inconsistent with resource plans developed based on a lowest cost and least risk basis while placing upward pressure on overall customer bills. This may impact our investment plans and financial condition. Finally, the requirement to procure power from these QF sources may impact our transmission system and require additional transmission facilities to be developed in order to integrate these resources, which also can impact overall customer bills. ##TABLE_START Operational Risks ##TABLE_END Our electric and natural gas operations involve numerous activities that may result in accidents, fires, system outages and other operating risks and costs that are unique to our industry. Inherent in our electric transmission and distribution and natural gas transmission and distribution operations are a variety of hazards and operating risks, such as breakdown or failure of equipment or processes, interruptions in fuel supply, supply chain interruptions, labor disputes, operator error, and catastrophic events such as fires, electric contacts, leaks, explosions, floods and intentional acts of destruction. For our natural gas lines located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the level of potential damages resulting from these risks could be significant. These risks could cause a loss of human life, facility shutdown or significant damage to property, service interruption, loss of customer load, environmental pollution, impairment of our operations, and substantial financial losses to us and others. Fire risk is significant in the western United States, including in our service territory. Various factors in recent years have contributed to increasing fire risk including dead and dying trees, warmer air temperatures, drought, wind, forest management practices, and land management practices. These factors increase the risk of a fire in both forests and grasslands. In forested areas, this issue has been heightened by mountain pine beetle and other infestations weakening and killing trees in our service territory. Worsening conditions as a result of climate change may increase the likelihood and magnitude of damages that may be caused by fires. Residential and commercial development into the wildland-urban interface has also led to an increasing trend in the degree of destruction from wildfires. Fires alleged to have been caused by our equipment potentially expose us to significant penalties and/or damage awards based on claims of strict liability, negligence, gross negligence, inverse condemnation, nuisance, trespass and others. Our equipment has been alleged to be involved in igniting wildfires although none have had a material adverse effect on our financial condition or results of operations. For our electric generating facilities, operational risks include facility shutdowns due to breakdown or failure of equipment or processes, interruptions in fuel supply, labor disputes, operator error, catastrophic events such as fires, explosions, floods, and intentional acts of destruction or other similar occurrences affecting the electric generating facilities; and operational changes necessitated by environmental legislation, litigation or regulation. The loss of a major electric generating facility would require us to find other sources of supply or ancillary services, if available, and expose us to higher purchased power costs and potential litigation which may not be recovered from customers. We maintain insurance against some, but not all, of these risks and losses. The occurrence of any of these events not fully covered by insurance could have a material adverse effect on our financial position and results of operations. Additionally, during peak-load periods our electric and natural gas systems in Montana are constrained. These constraints limit our ability to transmit electric energy within Montana and access electric energy from outside the service area. Our electric transmission facilities are also interconnected with those of third parties, and thus operation of these facilities could be adversely affected by unexpected or uncontrollable events. Our natural gas system is also constrained, which limits our on-system deliverability and the ability to transport gas. We are similarly exposed to risk of interconnection with third-party pipelines and are dependent upon their operation to serve customers. These transmission constraints and events could result in failure to provide reliable service to customers due to the inability to deliver energy supply resources, or could result in significant cost increases due to the inability to access lower cost sources of energy supply. Our electric and natural gas portfolios rely significantly on market purchases. This exposure adversely affects our ability to manage our operational requirements to reliably serve our customers, while exposing us to market volatility, which ultimately could adversely affect our results of operations and liquidity. We are obligated to supply power to retail customers and certain wholesale customers and procure natural gas to supply fuel for our natural gas fired generation. Our need to acquire flexible energy supply and capacity in the market to meet our electric and natural gas load serving obligations exposes us to certain risks including the ability to reliably serve customers and significant uncertainty in the cost of supply, which may not be recoverable. We rely upon a combination of base-load supply from our owned generation and market purchases to serve customers. The accredited capacity of our Montana portfolio of owned and long-term contracted electric generation resources covers 75 percent of our recent peak electric requirements, with remaining needs, including additional reserve margin, served through market purchases. In the past, Montana had been a net exporter of electric generation and we have relied upon Montana's excess generation for grid reliability and to physically serve customers. However, that situation in Montana has changed and we are predominantly a net importer, especially during peak demand. A significant number of base-load generation facilities, which may also serve to meet peak requirements, in the state and region have been retired or are scheduled to be retired in the next five to ten years. This includes Colstrip Units 1 and 2, representing 614 MWs of generation on a capacity basis, which ceased operations in January 2020. A decrease in the state and regions electric capacity, whether for operational reasons or litigation outcomes, may impair the reliability of the grid, particularly during peak demand periods. There can be no assurance that there will be available counterparties to contract with to serve our customers' needs, or that these counterparties will fulfill their obligations to us. There is also no assurance that the transmission capacity required to import market purchases will be available on transmission systems owned by us or by third parties. In addition, the suppliers under these agreements may experience financial or operational problems that inhibit their ability to fulfill their obligations to us. These conditions could result in an inability to physically deliver electricity to our customers. Losing electric service during extreme conditions carries significant consequences, as without our services our customers may be subjected to dire circumstances. Commodity pricing is an inherent risk component of our business operations and our financial results. Even though rate regulation is premised on full recovery of prudently incurred costs and a reasonable rate of return on invested capital, there can be no assurance that our costs are recoverable as discussed above. The prevailing market prices for electricity may fluctuate substantially over relatively short periods of time, potentially adversely impacting our results of operations, financial condition and cash flows due to our need for market purchases and the sharing component of the Montana PCCAM. During 2022, market prices for electricity and natural gas in peak periods were increasingly volatile, resulting in a significant under-collection of these costs impacting our results of operations and cash flows. In addition, our natural gas system serves both retail customers and the needs of natural gas fired electric generation. The natural gas system has capacity constraints that expose us to risks to be able to deliver natural gas during periods of peak demand. Fluctuations in actual weather conditions, generation availability, transmission constraints, and generation reserve margins may all have an impact on market prices for energy and capacity and the electricity consumption of our customers on a given day. Extreme weather conditions may force us to purchase electricity in the short-term market on days when weather is unexpectedly severe, and the pricing for market energy may be significantly higher on such days than the cost of electricity in our existing generation and contracts. Unusually mild weather conditions could leave us with excess power which may be sold in the market at a loss if the market price is lower than the cost of electricity in our existing contracts. Weather and weather patterns, including normal seasonal and quarterly fluctuations of weather, as well as extreme weather events that might be associated with climate change, could adversely affect our ability to manage our operational requirements to serve our customers, and ultimately adversely affect our results of operations and liquidity. Our electric and natural gas utility business is seasonal, and weather patterns can have a material impact on our financial performance. Demand for electricity and natural gas is often greater in the summer and winter months associated with cooling and heating. Because natural gas is heavily used for residential and commercial heating, the demand for this product depends heavily upon weather patterns throughout our market areas, and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our operations have historically generated less revenue and income when weather conditions are milder in the winter and cooler in the summer. Unusually mild winters or cool summers could adversely affect our results of operations and financial position. In addition, exceptionally hot summer weather or unusually cold winter weather could add significantly to working capital needs to fund higher than normal supply purchases to meet customer demand for electricity and natural gas. Our sensitivity to weather volatility is significant due to the absence of regulatory mechanisms, such as those authorizing revenue decoupling, lost margin recovery, and other innovative rate designs. Severe weather impacts, including but not limited to, blizzards, thunderstorms, high winds, microbursts, floods, fires, tornadoes and snow or ice storms can disrupt energy generation, transmission and distribution. We derive a significant portion of our energy supply from hydroelectric facilities, and the availability of water can significantly affect operations. Higher temperatures may decrease the Montana snowpack and impact the timing of run-off and may require us to purchase replacement power. Dry conditions, which exist in the West and in our service territory, also increase the threat of fires, which could threaten our communities and electric distribution and transmission lines and facilities. In addition, fires that are alleged to have been caused by our system could expose us to substantial property damage and other claims. Any damage caused as a result of fires could negatively impact our financial condition, results of operations or cash flows. The physical risks of climate change could include changes in weather conditions, such as changes in the amount or type of precipitation and extreme weather events. Climate change and the costs that may be associated with its impacts have the potential to affect our business in many ways, including increasing the cost incurred in providing electricity and natural gas, impacting the demand for and consumption of electricity and natural gas (due to change in both costs and weather patterns), and affecting the economic health of the regions in which we operate. Extreme weather conditions, especially those of prolonged duration, create high energy demand on our own and/or other systems and increase the risk we may be unable to reliably serve customers, causing brownouts and/or blackouts of our electric systems, and loss of gas supply. Risk of losing electricity or gas supply during extreme weather carries significant consequences as without our services our customers may be subjected to dire circumstances. Additionally, extreme weather conditions may raise market prices as we buy short-term energy to serve our own system. To the extent the frequency of extreme weather events increase, this could increase our cost of providing service. In addition, we may not recover all costs related to mitigating these physical and financial risks. Our results of operations may be impacted by disruptions to fuel supply or the electric grid that are beyond our control. We are exposed to risks related to performance of contractual obligations by our suppliers, which includes parties transporting natural gas. We are dependent on coal and natural gas for a significant portion of our electric generating capacity. We rely on suppliers to deliver coal and natural gas in accordance with short- and long-term contracts. We have certain supply and transportation contracts in place; however, there can be no assurance that the counterparties to these agreements will fulfill their obligations to supply and deliver coal and natural gas to us. For instance, there currently is litigation pending relating to adequacy of certain permits for the Rosebud Mine in Montana, which supplies coal to Colstrip and contains significant quantities of coal. In order to operate the Colstrip facility through its currently identified retirement date of 2042, it will be necessary to identify and contract for coal supply subsequent to expiration of our current contract. Moreover, the suppliers under these agreements may experience financial or technical problems that inhibit their ability to fulfill their obligations to us. In addition, the suppliers under these agreements may not be required to supply or transport coal and natural gas to us under certain circumstances, such as in the event of a natural disaster. Deliveries may be subject to short-term interruptions or reductions due to various factors, including transportation problems, weather, availability of equipment and labor shortages. Failure or delay by our suppliers of coal and natural gas deliveries could disrupt our ability to deliver electricity and require us to incur additional expenses to meet the needs of our customers. Also, because our generation and transmission systems are part of an interconnected regional grid, we face the risk of possible loss of business due to a disruption or black-out caused by an event such as a severe storm, generator or transmission facility outage on a neighboring system or the actions of a neighboring utility. Any such disruption could result in a significant decrease in revenues and significant additional costs to repair assets, which could have a material adverse impact on our financial position, results of operations and cash flows. Our revenues, results of operations and financial condition are impacted by customer growth and usage in our service territories and may fluctuate with current economic conditions or response to price increases. We are also impacted by market conditions outside of our service territories related to demand for transmission capacity and wholesale electric pricing. Our revenues, results of operations and financial condition are impacted by customer growth and usage, which can be impacted by a number of factors, including the voluntary reduction of consumption of electricity and natural gas by our customers in response to increases in prices and demand-side management programs, economic conditions impacting decreases in their disposable income, and the use of distributed generation resources or other emerging technologies for electricity. Advances in distributed generation technologies that produce power, including fuel cells, micro-turbines, wind turbines and solar cells, may reduce the cost of alternative methods of producing power to a level competitive with central power station electric production. Customer-owned generation itself reduces the amount of electricity purchased from utilities and may have the effect of inappropriately increasing rates generally and increasing rates for customers who do not own generation, unless retail rates are designed to collect distribution grid costs across all customers in a manner that reflects the benefit from their use. Such developments could affect the price of energy, could affect energy deliveries as customer-owned generation becomes more cost-effective, could require further improvements to our distribution systems to address changing load demands and could make portions of our electric system power supply and transmission and/or distribution facilities obsolete prior to the end of their useful lives. Such technologies could also result in further declines in commodity prices or demand for delivered energy. Decreasing use per customer (driven, for example, by appliance and lighting efficiency) and the availability of cost-effective distributed generation, put downward pressure on load growth. Reductions in usage, attributable to various factors could materially affect our results of operations, financial position, and cash flows through, among other things, reduced operating revenues, increased operating and maintenance expenses, and increased capital expenditures, as well as potential asset impairment charges or accelerated depreciation and decommissioning expenses over shortened remaining asset useful lives. Demand for our Montana transmission capacity fluctuates with regional demand, fuel prices and weather related conditions. The levels of wholesale sales depend on the wholesale market price, market participants, transmission availability, the availability of generation, and the ongoing development of the Western Energy Imbalance Market, among other factors. Declines in wholesale market price, availability of generation, transmission constraints in the wholesale markets, or low wholesale demand could reduce wholesale sales. These events could adversely affect our results of operations, financial position and cash flows. Cyber and physical attacks, threats of terrorism and catastrophic events that could result from terrorism, or individuals and/or groups attempting to disrupt our business, or the businesses of third parties, may affect our operations in unpredictable ways and could adversely affect our liquidity and results of operations. Failure to maintain the security of personally identifiable information could adversely affect us. Business Operations - We are subject to the potentially adverse operating and financial effects of terrorist acts and threats, as well as cyber attacks, physical security breaches and other disruptive activities of individuals or groups, and theft of our critical infrastructure information. Our generation, transmission and distribution facilities are deemed critical infrastructure and provide the framework for our service infrastructure. Cyber crime, which includes the use of malware, phishing attempts, computer viruses, and other means for disruption or unauthorized access has increased in frequency, scope, and potential impact in recent years. Our assets and the information technology systems on which they depend could be direct targets of, or indirectly affected by, cyber attacks and other disruptive activities, including those that impact third party facilities that are interconnected to us. Any significant interruption of these assets or systems could prevent us from fulfilling our critical business functions including delivering energy to our customers, and sensitive, confidential and other data could be compromised. Security threats continue to evolve and transform. T he risk of cyber-based attacks is heightened due to recent geopolitical events as well as employees working and accessing our technology infrastructure remotely. We and our third-party vendors have been subject to, and will likely continue to be subject to, attempts to gain unauthorized access to systems, to confidential data, or to disrupt operatio ns. With the continuing rise in ransomware and other cyber-based threats we have been analyzing our technology platforms and monitoring for signs of potential intrusions. We have also been reaching out to our vendors, suppliers and contractors requesting that they take appropriate measures. None of these attempts has individually or in the aggregate resulted in a security incident with a material impact on our financial condition or results of operations. However, despite implementation of security and control measures, there can be no as surance that we will be able to prevent the unauthorized access of our systems and data, or the disruption of our operations, either of which could have a material impact. These events, and governmental actions in response, could result in a material decrease in revenues and significant additional costs to repair and insure assets, and could adversely affect our operations by contributing to the disruption of supplies and markets for electricity, natural gas, oil and other fuels. These events could also impair our ability to raise capital by contributing to financial instability and reduced economic activity. Personally Identifiable Information - Our information systems and those of our third-party vendors contain confidential information, including information about customers and employee s. Customers, shareholders, and employees expect that we will adequately protect their personal information. The regulatory environment surrounding information security and privacy is increasingly demanding. A data breach invol ving theft, improper disclosure, or other unauthorized access to or acquisition of confidential information could subject us to penalties for violation of applicable privacy laws, claims by third parties, and enforcement actions by government agencies. It could also reduce the value of proprietary information, and harm our reputation. We maintain insurance against some, but not all, of these risks and losses. The occurrence of any of these events not fully covered by insurance could have a material adverse effect on our financial position and results of operations. We may have difficulty cost-effectively completing certain operations activities and construction projects due to inflationary pressures or if our third-party business partners are unable to deliver ordered supplies or complete contracted services timely, including workforce shortages or macro supply chain disruptions. We place significant reliance on our third-party business partners to supply materials, equipment and labor necessary for us to operate our utility and reliably serve current customers and future customers. As a result of current macroeconomic conditions, both nationally and globally, we have recently experienced issues with our supply chain for materials and components used in our operations and capital project construction activities. Issues include higher prices, scarcities/shortages, longer fulfillment times for orders from our suppliers, workforce availability, and wage increases. Should these economic conditions and issues continue, we could have difficulty completing the operational activities necessary to serve our customers safely and reliably, and/or achieving our capital investment program, which ultimately could result in higher customer utility rates, longer outages, and could have a material adverse impact on our business, financial condition and operations. Failure to attract and retain an appropriately qualified workforce could affect our operations. We require skilled labor to perform specialized utility functions. Turnover of key employees without appropriate replacements may lead to operating challenges and increased costs. Some of the challenges include lack of resources, loss of knowledge, and time required for replacement employees to develop necessary skills. Wage inflation nationally and increased competitive labor markets may make it difficult to attract employees. Failure to identify qualified replacement employees could result in decreased productivity and increased safety costs. If we are unable to attract and retain an appropriately qualified workforce, our operations could be negatively affected. We are also subject to multiple collective bargaining agreements. Future negotiation of these collective bargaining agreements could lead to work stoppages or other disruptions to our operations, which could adversely affect our financial condition and results of operations. A pandemic or similar widespread public health concern could have a material negative impact on our business, financial condition and results of operations. The actual or perceived effects of a disease outbreak, epidemic, pandemic or similar widespread public health concern, such as COVID-19, will likely negatively affect our business, financial condition and results of operations. The COVID-19 pandemic has had widespread impacts on people, economies, businesses and financial markets. While the COVID-19 pandemic did not cause material disruptions to our operations, we could experience such disruptions in the future as a result of a pandemic (or a similar widespread public health concern) due to, among other things, quarantines, increased cyber risk due to employees working from home, worker absenteeism as a result of illness or other factors, social distancing measures and other travel, health-related, business or other restrictions. If a significant percentage of our workforce is unable to work, including because of illness, travel restrictions, or government mandates in connection with pandemics or disease outbreaks, our operations may be negatively affected. Any such workforce implications and / or limitations or closures impact our ability to achieve our capital investment program and could have a material adverse impact on our ability to serve our customers and on our business, financial condition and results of operations. ##TABLE_START Liquidity and Financial Risks ##TABLE_END Our plans for future expansion through the acquisition of assets, capital improvements to existing assets, generation investments, and transmission grid expansion involve substantial risks. Our business strategy includes significant investment in capital improvements and additions to modernize existing infrastructure, generation investments and transmission capacity expansion. The completion of generation and natural gas investments and transmission projects are subject to many construction and development risks, including, but not limited to, risks related to permitting, financing, regulatory recovery, escalating costs of materials and labor, meeting construction budgets and schedules, and environmental compliance. In addition, these capital projects may require a significant amount of capital expenditures. We cannot provide certainty that adequate external financing will be available to support such projects. Additionally, borrowings incurred to finance construction may adversely impact our leverage, which could increase our cost of capital. Acquisitions include a number of risks, including but not limited to, regulatory approval, regulatory conditions, additional costs, the assumption of material liabilities, the diversion of our attention from daily operations to the integration of the acquisition, difficulties in assimilation and retention of employees, and securing adequate capital to support the transaction. The regulatory process in which rates are determined may not result in rates that produce full recovery of our investments, or a reasonable rate of return. Uncertainties also exist in assessing the value, risks, profitability, and liabilities associated with certain businesses or assets and there is a possibility that anticipated operating and financial synergies expected to result from an acquisition do not develop. The failure to successfully integrate future acquisitions that we may choose to undertake could have an adverse effect on our financial condition and results of operations. Access to capital markets is critical to our operations and our capital structure. Increasing interest rates could have a material negative impact on our financial condition. We have significant capital requirements that we expect to fund, in part, by accessing capital markets. As such, the state of financial markets and credit availability in the global, U.S. and regional economies impacts our financial condition. We could experience increased borrowing costs or limited access to capital on reasonable terms. We access long-term capital markets to finance capital expenditures, repay maturing long-term debt and obtain additional working capital from time-to-time. For example, we have $145 million of 2% Montana secured debt maturing in 2023. Our ability to access capital on reasonable terms is subject to numerous factors and market conditions, many of which are beyond our control. If we are unable to obtain capital on reasonable terms, it may limit or prohibit our ability to finance capital expenditures and repay maturing long-term debt. Our liquidity needs could exceed our short-term credit availability and lead to defaults on various financing arrangements. We would also likely be prohibited from paying dividends on our common stock. We are subject to financial risks associated with the transition to a lower carbon economy. The risks related to our transition to a lower-carbon economy, creates financial risk. Transition risks represent those risks related to the social and economic changes needed to shift toward a lower carbon future. These risks are often interconnected, representing policy and regulatory changes, technology and market risks, and risks to our reputation and financial performance. Potential regulation associated with climate change legislation could pose financial risks to us. The U.S. is a party to the United Nations' "Paris Agreement" on climate change, and that agreement along with other potential legislation and regulation discussed above, could result in enforceable GHG emission reduction requirements that could lead to increased compliance costs for us. For example, the EPA has indicated that it is currently "evaluating additional opportunities" to reduce GHG emissions from existing power plants. As we expand our energy generation asset mix, the ability to integrate renewable technologies into our operations and maintain reliability and affordability is a risk. The intermittency of renewables remains a critical challenge particularly as cost-efficient energy storage is still in development. Other technology risks include the need for significant upfront financial investments, lengthy development timelines, and the uncertainty of integration and scalability across our entire service territory. To the extent that any climate change adversely affects the national or regional economic health through physical impacts or increased rates caused by the inclusion of additional regulatory costs, CO_2 taxes or imposed costs, we may be adversely impacted. There are also increasing risks for energy companies from shareholders currently invested in fossil-fuel energy companies concerned about the potential effects of climate change who may elect in the future to shift some or all of their investments into entities that emit lower levels of GHG emissions or into non-energy related sectors. Institutional investors and lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable investing and lending practices and some of them may elect not to provide funding for fossil fuel energy companies. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less than ideal terms and conditions. We may be subject to financial risks from private party litigation relating to GHG emissions. Defense costs associated with such litigation can be significant and an adverse outcome could require substantial capital expenditures and could possibly require payment of substantial penalties or damages. Such payments or expenditures could affect results of operations, financial condition or cash flows if such costs are not recovered through regulated rates. We must meet certain credit quality standards. If we are unable to maintain investment grade credit ratings, our liquidity, access to capital and operations could be materially adversely affected. A downgrade of our credit ratings to less than investment grade could adversely affect our liquidity. We continue to maintain our investment grade credit ratings. During a 2022 review process, Fitch Ratings downgraded our rating with a stable outlook. Certain of our credit agreements and other credit arrangements with counterparties require us to provide collateral in the form of letters of credit or cash to support our obligations if we fall below investment grade. Also, a downgrade below investment grade could hinder our ability to raise capital on favorable terms and would increase our borrowing costs. Higher interest rates on borrowings with variable interest rates could also have an adverse effect on our results of operations. Our obligation to include a minimum annual quantity of power in our Montana electric supply portfolio at an agreed upon price per MWH could expose us to material commodity price risk if certain QFs under contract with us do not perform during a time of high commodity prices, as we are required to make up the difference. In addition, we are subject to price escalation risk with one of the largest QF contracts. As part of a stipulation in 2002 with the MPSC and other parties, we agreed to include a minimum annual quantity of power in our Montana electric supply portfolio at an agreed upon price per MWH through June 2029. This obligation is reflected in the electric QF liability, which reflects the unrecoverable costs associated with these specific QF contracts per the stipulation. The annual minimum energy requirement is achievable under normal operations of these facilities, including normal periods of planned and forced outages. However, to the extent the supplied power for any year does not reach the minimum quantity set forth in the settlement, we are obligated to purchase the difference from other sources. The anticipated source for any shortfall is the wholesale market, which would subject us to commodity price risk if the cost of replacement power is higher than contracted rates. In addition, we are subject to price escalation risk with one of the largest contracts included in the electric QF liability due to variable contract terms. In recording the electric QF liability, we estimate an annual escalation rate over the remaining term of the contract (through June 2024). To the extent the annual escalation rate exceeds our estimate, our results of operations, cash flows and financial position could be adversely affected. Changes in tax law may significantly impact our business. We are subject to taxation by the various taxing authorities at the federal, state and local levels where we operate. Similar to the Tax Cuts and Jobs Act, sweeping legislation or regulation could be enacted by any of these governmental authorities which may affect our tax burden. Changes may include numerous provisions that affect businesses, including changes to corporate tax rates, business-related exclusions, and deductions and credits. The outcome of regulatory proceedings regarding the extent to which a change in corporate tax rate will affect our utility customers and the time period over which that change will occur could significantly impact future earnings and cash flows. Separately, a challenge by a taxing authority, changes in taxing authorities administrative interpretations, decisions, policies and positions, our ability to utilize tax benefits such as carryforwards or tax credits, or a deviation from other tax-related assumptions may cause actual financial results to deviate from previous estimates and therefore may impact our results of operations, cash flows and financial position. We are subject to counterparty credit risk. We enter into transactions to buy and sell power, natural gas, and transmission service. We could recognize financial losses as a result of volatility in the market value of these contracts or if a counterparty fails to perform. Certain of these contracts may result in the receipt of, or posting of, collateral with counterparties. Fluctuations in commodity prices that lead to the posting of collateral with counterparties negatively impact liquidity, and downgrades in our credit ratings may lead to additional collateral posting requirements. We are a participant in the energy markets, including the EIM, and engage in direct and indirect power purchase and sale transactions in connection with that participation. The EIM has collateral posting requirements based on established credit criteria, but there is no assurance the collateral will be sufficient to cover obligations that counterparties may owe each other in the EIM and any such credit losses could be socialized to all EIM participants, including us. A significant failure of a participant in the EIM to make payments when due on its obligations could have a ripple effect on various of our counterparties in the power and gas markets if those counterparties experience ancillary liquidity issues, and could generally result in a decline in the ability of our counterparties to perform on their obligations. We also extend credit to our customers in the ordinary course of business in each of our operating segments. Our customers' ability to pay depends on a variety of factors including macroeconomic conditions, local economic conditions, including unemployment rates, and industry conditions in which our commercial and industrial customers operate. Increased customer delinquencies and bad debts could adversely impact our operating results and liquidity. Poor investment performance of plan assets of our defined benefit pension and postretirement benefit plans, in addition to other factors impacting these costs, could unfavorably impact our results of operations and liquidity. Our costs for providing defined benefit retirement and postretirement benefit plans are dependent upon a number of factors. Assumptions related to future costs, return on investments and interest rates have a significant impact on our funding requirements related to these plans. These estimates and assumptions may change based on economic conditions, actual stock market performance and changes in governmental regulations. Without sustained growth in the plan assets over time and depending upon interest rate changes as well as other factors noted above, the costs of such plans reflected in our results of operations and financial position and cash funding obligations may change significantly from projections.

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Item 1. Business. Introduction OGE Energy is a holding company with investments in energy and energy services providers offering physical delivery and related services for electricity in Oklahoma and western Arkansas. Prior to September 30, 2022, OGE Energy also held investments in Enable and Energy Transfer, which offers natural gas, crude oil and NGL services. OGE Energy reports these activities through two business segments: (i) electric company operations and (ii) natural gas midstream operations. For periods prior to the December 2, 2021 closing of the Enable and Energy Transfer merger, OGE Energy accounted for its investment in Enable as an equity method investment and reported it within OGE Energy's natural gas midstream operations segment. For the period of December 2, 2021 through September 30, 2022, OGE Energy accounted for its investment in the Energy Transfer units it acquired in the merger as an investment in equity securities. As of the end of September 2022, OGE Energy had sold all of its Energy Transfer limited partner units, becoming primarily an electric company. Electric Company Operations . OGE Energy's electric company operations are conducted through OGE, which generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. OGE's rates are subject to regulation by the OCC, the APSC and the FERC. OGE was incorporated in 1902 under the laws of the Oklahoma Territory and is a wholly-owned subsidiary of OGE Energy. OGE is the largest electric company in Oklahoma, and its franchised service territory includes Fort Smith, Arkansas and the surrounding communities. OGE sold its retail natural gas business in 1928 and is no longer engaged in the natural gas distribution business. Natural Gas Midstream Operations. For the period of December 2, 2021 to September 30, 2022, OGE Energy's natural gas midstream operations segment included OGE Energy's investment in Energy Transfer's equity securities acquired in the Enable/Energy Transfer merger. For the year ended December 31, 2022, this segment also includes legacy Enable seconded employee pension and postretirement costs. Prior to OGE Energy's sale of all Energy Transfer limited partner units, the investment in Energy Transfer's equity securities was held through wholly-owned subsidiaries and ultimately OGE Holdings. OGE Energy no longer has any ownership interest in natural gas midstream operations. The Registrants' principal executive offices are located at 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma, 73101-0321 (telephone 405-553-3000). OGE Energy's website address is www.oge.com. Through OGE Energy's website, OGE Energy makes available, free of charge, the Registrants' annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission. OGE Energy's website and the information contained therein or connected thereto are not intended to be incorporated into this Form 10-K and should not be considered a part of this Form 10-K. Reports filed with the Securities and Exchange Commission are also made available on its website at www.sec.gov. Strategy OGE Energy's purpose is to energize life, providing life-sustaining and life-enhancing products and services, while honoring its commitment to strengthen communities. Its business model is centered around growth and sustainability for employees (internally referred to as members), communities and customers and the owners of OGE Energy, its shareholders. OGE Energy is focused on: delivering top-quartile safety results, while enabling members to deliver improved value to their communities, customers and shareholders; transforming the customer experience by centering decisions on customer impact that will drive customer operations, communications program and product development and the digital experience including increased personalization and self-service; providing safe, reliable energy to the communities and customers it serves, with a particular focus on enhancing the value of the grid by improving reliability and resiliency; leading economic development and job growth by attracting new and diverse businesses to improve the infrastructure of the communities in Oklahoma and Arkansas; ensuring the necessary mix of generation resources to meet the long-term capacity needs of our customers, with a progressively cleaner generation portfolio; maintaining customer rates that are some of the most affordable in the country by continuing focus on innovation, intellectual curiosity and execution with excellence; delivering on earnings commitments to shareholders to enhance access to lower-cost debt and equity capital that is needed to deploy infrastructure for the long-term economic health of its communities; having strong regulatory and legislative relationships, built on integrity, for the long-term benefit of our customers, communities, shareholders and members; and developing and growing our members to be able to provide a greater contribution to the company's success, while also improving their own lives. OGE Energy is focused on creating long-term shareholder value by targeting the consistent growth of earnings per share of five to seven percent at the electric company, supported by strong load growth enabled by low customer rates and a strategy of investing in lower risk infrastructure projects that improve the economic vitality of the communities it serves in Oklahoma and Arkansas. In the next five years, OGE Energy expects to continue to grow the dividend, targeting a dividend payout ratio of 65 to 70 percent. Over the next several years, OGE Energy expects earnings per share growth to exceed the dividend growth rate to help achieve this target. OGE Energy's financial objectives also include maintaining investment grade credit ratings and providing a strong and reliable dividend for shareholders. OGE Energy's long-term sustainability is predicated on providing exceptional customer experiences, investing in grid improvements and increasingly cleaner generation resources, environmental stewardship, strong governance practices and caring for and supporting its members and communities. Electric Operations - OGE General OGE provides retail electric utility service to approximately 889,000 customers in Oklahoma and western Arkansas. The service area covers 30,000 square miles including Oklahoma City, the largest city in Oklahoma, Fort Smith, Arkansas, the third largest city in that state, and other large communities with their contiguous rural and suburban areas throughout Oklahoma and western Arkansas. OGE derived 92 percent of its total electric operating revenues in 2022 from sales in Oklahoma and the remainder from sales in Arkansas. OGE does not currently serve wholesale customers in either state. In 2022, OGE's system control area peak demand was 7,301 MWs on July 19, 2022, and OGE's load responsibility peak demand was 6,498 MWs on July 19, 2022. The following table presents system sales and variations in system sales for 2022, 2021 and 2020. ##TABLE_START Year Ended December 31 2022 vs. 2021 2021 vs. 2020 System sales (Millions of MWh) 30.0 8.3% 27.7 2.6% 27.0 ##TABLE_END OGE is subject to competition in various degrees from government-owned electric systems, municipally-owned electric systems, rural electric cooperatives and, in certain respects, from other private utilities, power marketers and cogenerators. Oklahoma law forbids the granting of an exclusive franchise to a utility for providing electricity. Besides competition from other suppliers or marketers of electricity, OGE competes with suppliers of other forms of energy. The degree of competition between suppliers may vary depending on relative costs and supplies of other forms of energy. It is possible that changes in regulatory policies or advances in technologies such as fuel cells, microturbines, windmills and photovoltaic solar cells will reduce costs of new technology to levels that are equal to or below that of most central station electricity production. OGE's ability to maintain relatively low cost, efficient and reliable operations is a significant determinant of its competitiveness. OKLAHOMA GAS AND

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ELECTRIC COMPANY CERTAIN OPERATING STATISTICS ##TABLE_START Year Ended December 31 ELECTRIC ENERGY (Millions of MWh) Generation (exclusive of station use) 13.6 16.3 17.5 Purchased 19.0 14.6 12.9 Total generated and purchased 32.6 30.9 30.4 OGE use, free service and losses (1.5) (1.6) (1.4) Electric energy sold 31.1 29.3 29.0 ELECTRIC ENERGY SOLD (Millions of MWh) Residential 10.4 9.6 9.5 Commercial 7.9 6.8 6.3 Industrial 4.2 4.2 4.2 Oilfield 4.4 4.2 4.2 Public authorities and street light 3.1 2.9 2.8 System sales 30.0 27.7 27.0 Integrated market 1.1 1.6 2.0 Total sales 31.1 29.3 29.0 ELECTRIC OPERATING REVENUES (In millions) Residential $ 1,307.0 $ 1,342.1 $ 869.0 Commercial 825.6 766.9 479.4 Industrial 322.4 328.2 197.3 Oilfield 306.7 316.8 172.3 Public authorities and street light 298.9 289.5 176.9 System sales revenues 3,060.6 3,043.5 1,894.9 Provision for rate refund (1.2) 3.8 Integrated market 163.8 468.9 49.6 Transmission 131.7 140.2 143.3 Other 20.8 1.1 30.7 Total operating revenues $ 3,375.7 $ 3,653.7 $ 2,122.3 ACTUAL NUMBER OF ELECTRIC CUSTOMERS (At end of period) Residential 756,751 749,091 740,174 Commercial 105,018 103,337 100,200 Industrial 2,464 2,585 2,710 Oilfield 6,791 6,804 6,822 Public authorities and street light 17,735 17,630 17,483 Total customers 888,759 879,447 867,389 ##TABLE_END Regulation and Rates OGE's retail electric tariffs are regulated by the OCC in Oklahoma and by the APSC in Arkansas. The issuance of certain securities by OGE is also regulated by the OCC and the APSC. OGE's transmission activities, short-term borrowing authorization and accounting practices are subject to the jurisdiction of the FERC. The Secretary of the U.S. Department of Energy has jurisdiction over some of OGE's facilities and operations. In 2022, 88 percent of OGE's electric revenue was subject to the jurisdiction of the OCC, eight percent to the APSC and four percent to the FERC. The OCC and the APSC require that, among other things, (i) OGE Energy permits the OCC and the APSC access to the books and records of OGE Energy and its affiliates relating to transactions with OGE; (ii) OGE Energy employ accounting and other procedures and controls to protect against subsidization of non-utility activities by OGE's customers; and (iii) OGE Energy refrain from pledging OGE assets or income for affiliate transactions. In addition, the FERC has access to the books and records of OGE Energy and its affiliates as the FERC deems relevant to costs incurred by OGE or necessary or appropriate for the protection of utility customers with respect to the FERC jurisdictional rates. For information concerning OGE's recently completed and currently pending regulatory proceedings, see Note 14 within Item 8. Financial Statements and Supplementary Data. Regulatory Assets and Liabilities OGE, as a regulated utility, is subject to accounting principles for certain types of rate-regulated activities, which provide that certain incurred costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment. OGE records certain incurred costs and obligations as regulatory assets or liabilities if, based on regulatory orders or other available evidence, it is probable that the costs or obligations will be included in amounts allowable for recovery or refund in future rates. Management continuously monitors the future recoverability of regulatory assets. When in management's judgment future recovery becomes impaired, the amount of the regulatory asset is adjusted, as appropriate. If OGE were required to discontinue the application of accounting principles for certain types of rate-regulated activities for some or all of its operations, it could result in writing off the related regulatory assets or liabilities, which could have significant financial effects. See Note 1 within Item 8. Financial Statements and Supplementary Data for further discussion of OGE's regulatory assets and liabilities. Rate Structures Oklahoma OGE's standard tariff rates include a cost of service component (including an authorized return on capital) plus a fuel adjustment clause mechanism that allows OGE to pass through to customers the actual cost of fuel and purchased power. OGE offers several alternative customer programs and rate options, as described below. Under OGE's Smart Grid-enabled SmartHours programs, time-of-use and variable peak pricing rates offer customers the ability to save on their electricity bills by shifting some of the electricity consumption to off-peak times when demand for electricity is lowest. The Guaranteed Flat Bill option for residential and small general service accounts allows qualifying customers the opportunity to purchase their electricity needs at a set monthly price for an entire year. The Renewable Energy Credit purchase program, the Green Power Wind Rider and the Utility Solar Program are rate options that make renewable energy resources available as a voluntary option to all OGE Oklahoma retail customers. OGE's ownership and access to wind and solar resources makes the renewable option a possible choice in meeting the renewable energy needs of OGE's conservation-minded customers. Load Reduction is a voluntary load curtailment program that provides those OGE commercial and industrial customers who enroll with the opportunity to curtail usage on a voluntary basis when power delivery system conditions merit curtailment action. Large customers greater than 50 MWs who enroll in the program are also required to participate in Direct Load Control, giving OGE direct control over the curtailable portion of the customer's load. Customers that curtail their usage will receive credit for their curtailment response. OGE offers certain qualifying customers day-ahead price and flex price rate options which allow participating customers to adjust their electricity consumption based on price signals received from OGE. The prices for the day-ahead price and flex price rate options are based on OGE's projected next day hourly operating costs. In addition to specific rate structures, OGE provides customers with other programs such as Average Monthly Billing which helps to make the customer's bill more predictable on a monthly basis. Similarly, OGE has energy efficiency programs which provide qualified customers with programs such as in-home weatherization and opportunities to lower their monthly bill. OGE also has a Low Income Assistance Program and a Senior Citizen Discount, which provide qualified customers with a monthly bill credit. OGE has Public Schools-Demand and Public Schools Non-Demand rate classes that provide OGE with flexibility to provide targeted programs for load management to public schools and their unique usage patterns. OGE also provides service level, seasonal and time period fuel charge differentiation that allows customers to pay fuel costs that better reflect the underlying costs of providing electric service. Lastly, OGE has a military base rider that demonstrates Oklahoma's continued commitment to its military partners. The previously discussed rate options, coupled with OGE's other rate choices, provide many tariff options for OGE's Oklahoma retail customers. The revenue impacts associated with these options are not determinable in future years because customers may choose to remain on existing rate options instead of volunteering for the alternative rate option choices. Revenue variations may occur in the future based upon changes in customers' usage characteristics if they choose alternative rate options. Arkansas OGE's standard tariff rates include a cost of service component (including an authorized return on capital) plus an energy cost recovery mechanism that allows OGE to pass through to customers the actual cost of fuel and purchased power. OGE's current rate order from the APSC includes a formula rate rider that provides for an annual adjustment to rates if the earned rate of return falls outside of a plus or minus 50 basis point dead-band around the allowed return on equity. Adjustments are limited to plus or minus four percent of revenue for each rate class for the 12 months preceding the test period. The initial term for the formula rate rider was not to exceed five years from the date of the APSC final order in the last general rate review, May 18, 2017, unless additional approval was obtained from the APSC. As further described in Note 14 within Item 8. Financial Statements and Footnotes, in September 2022, the APSC denied OGE's extension request for the formula rate rider, as the APSC and OGE did not agree on the APSC's approved debt-to-equity ratio for OGE. Despite the denial of the extension request, the APSC ruled on January 20, 2023 that OGE is able to undertake two more true-up updates to its formula rate rider with adjustments to rates occurring in April 2023 and April 2024. Subsequent to the April 2024 update, the formula rate rider will continue until new rates are set in a future general rate review. OGE offers several alternative customer programs and rate options, as described below. The time-of-use and variable peak pricing tariffs allow participating customers to save on their electricity bills by shifting some of the electricity consumption to off-peak times when demand for electricity is lowest. The Renewable Energy Credit purchase program and the Universal Solar Program are rate options that make renewable energy resources available as a voluntary option to all OGE Arkansas retail customers. OGE's ownership and access to wind and solar resources makes the renewable option a possible choice in meeting the renewable energy needs of OGE's conservation-minded customers. Load Reduction is a voluntary load curtailment program that provides OGE's commercial and industrial customers with the opportunity to curtail usage on a voluntary basis and receive a billing credit when OGE's system conditions merit curtailment action. OGE offers certain qualifying customers day-ahead price and flex price rate options which allow participating customers to adjust their electricity consumption based on a price signal received from OGE. The day-ahead price and flex price rate options are based on

OGE's projected next day hourly operating costs. In addition to specific rate structures, OGE provides customers with other programs such as Levelized Billing Plan which helps to make the customer's bill more predictable on a monthly basis. Similarly, OGE has energy efficiency programs which provide qualified customers with programs such as in-home weatherization and opportunities to lower their monthly bill. Fuel Supply and Generation The following table presents the OGE-generated energy produced and purchased, by type, for the last three years. ##TABLE_START Generation Mix (A) Natural gas % % % Coal % % % Renewable % % % Total % % % ##TABLE_END (A) Generation mix calculated as a percent of net MWhs generated and includes purchased power agreements. OGE participates in the SPP Integrated Marketplace. As part of the Integrated Marketplace, the SPP has balancing authority responsibilities for its market participants. The SPP Integrated Marketplace functions as a centralized dispatch, where market participants, including OGE, submit offers to sell power to the SPP from their resources and bid to purchase power from the SPP for their customers. The SPP Integrated Marketplace is intended to allow the SPP to optimize supply offers and demand bids based upon reliability and economic considerations and to determine which generating units will run at any given time for maximum cost-effectiveness within the SPP area. As a result, OGE's generating units produce output that is different from OGE's customer load requirements. Net fuel and purchased power costs are generally recoverable through fuel adjustment clauses. The following table presents the weighted-average cost of fuel used, by type, for the last three years. ##TABLE_START Fuel Cost (A) (In cents/Kilowatt-Hour) Natural gas 7.032 11.907 2.077 Coal 3.253 1.935 1.821 Renewable Total 5.480 6.833 1.863 ##TABLE_END (A) Total fuel and purchased power weighted-average cost was 5.096, 6.892 and 2.117 cents per kilowatt-hour in 2022, 2021 and 2020, respectively. The changes in the weighted average cost of fuel in 2022 compared to 2021 and in 2021 compared to 2020 were primarily due to inflated fuel costs in 2021 during Winter Storm Uri. Fuel costs are generally recoverable through OGE's fuel adjustment clauses that are approved by the OCC and the APSC, with the exception of Winter Storm Uri fuel costs in 2021 which were recovered in Oklahoma in 2022 through securitization and which are being recovered in Arkansas over 10 years through a regulatory asset mechanism. See Notes 1 and 14 within Item 8. Financial Statements and Supplementary Data for further discussion. Of OGE's 7,240 total MWs of generation capability reflected in the table within Item 2. Properties, 4,904 MWs, or 67.7 percent, are from natural gas generation, 1,534 MWs, or 21.2 percent, are from coal generation, 321 MWs, or 4.4 percent, are from dual-fuel generation (coal/gas), 449 MWs, or 6.2 percent, are from wind generation and 32 MWs, or 0.5 percent, are from solar generation. Natural Gas As a participant in the SPP Integrated Marketplace, OGE purchases its natural gas supply through short-term agreements. OGE relies on a combination of natural gas base load agreements and call agreements, whereby OGE has the right but not the obligation to purchase a defined quantity of natural gas, combined with day and intra-day purchases to meet the demands of the SPP Integrated Marketplace. In 2022, OGE expanded its physical storage capacity by entering into two storage service contracts. These two contracts provide OGE security in both volume and price to further help protect customers against volatile natural gas prices. Coal OGE's coal-fired units are designed to burn primarily low sulfur western sub-bituminous coal. The combination of all 2022 coal purchased had a weighted average sulfur content of 0.25 percent. Based on the average sulfur content and EPA-certified data, OGE's coal units have an approximate emission rate of 0.2 lbs. of SO 2 per MMBtu. For 2023 through 2025, OGE has coal supply agreements for 100 percent of its expected coal requirements for both the Sooner and River Valley facilities. For the Muskogee facility, OGE has a majority of its expected 2023 coal requirements met through a coal supply agreement and will fill any additional coal needs through term agreements, spot purchases and the use of existing inventory. In 2022, OGE purchased 3.1 million tons of coal from its sub-bituminous suppliers and 0.011 million tons from its bituminous suppliers. See Environmental Laws and Regulations within Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations for a discussion of environmental matters which may affect OGE in the future, including its utilization of coal. Wind OGE owns the 120 MW Centennial, 101 MW OU Spirit and 228 MW Crossroads wind farms. OGE's current wind power portfolio also includes purchased power contracts as presented in the following table. ##TABLE_START Company Location Original Term of Contract Expiration of Contract MWs CPV Keenan Woodward County, OK 20 years 152.0 Edison Mission Energy Dewey County, OK 20 years 130.0 NextEra Energy Blackwell, OK 20 years 60.0 ##TABLE_END Solar OGE currently owns and operates the solar sites presented in the following table. ##TABLE_START Name Location Year Completed Photovoltaic Panels MWs Mustang Oklahoma City, OK 9,867 2.5 Covington Covington, OK 38,000 9.7 Choctaw Nation Durant, OK 15,344 5.0 Chickasaw Nation Davis, OK 15,344 5.0 Branch Branch, AR 15,444 5.0 Durant 2 Durant, OK 15,471 5.0 ##TABLE_END OGE issued a request for proposals for solar in 2022 based on generation needs established in its October 2021 IRP. OGE will continue to evaluate the need to add additional solar sites to its generation portfolio based on customer demand, cost and reliability. Environmental Matters The activities of OGE are subject to numerous stringent and complex federal, state and local laws and regulations governing environmental protection. These laws and regulations can change, restrict or otherwise impact the Registrants' business activities in many ways, including the handling or disposal of waste material, planning for future construction activities to avoid or mitigate harm to threatened or endangered species and requiring the installation and operation of emissions or pollution control equipment. Failure to comply with these laws and regulations could result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. Management believes that all of the Registrants' operations are in substantial compliance with current federal, state and local environmental standards. President Biden's Administration has taken a number of actions that adopt policies and affect environmental regulations, including issuance of executive orders that instruct the EPA and other executive agencies to review certain rules that affect OGE with a view to achieving nationwide reductions in greenhouse gas emissions. OGE is monitoring these actions which are in various stages of being implemented. At this point in time, the impacts of these actions on the Registrants' results of operations, if any, cannot be determined with any certainty. In the meantime, the Registrants continue to have obligations to take or complete action under current environmental rules. Management continues to evaluate the Registrants' compliance with existing and proposed environmental legislation and regulations and implement appropriate environmental programs in a competitive market but at the current time, based on existing rules, does not expect capital expenditures for environmental control facilities to be material for 2023 or 2024. For further discussion of environmental matters and capital expenditures related to environmental factors that may affect the Registrants, see 2022 Capital Requirements, Sources of Financing and Financing Activities, Future Capital Requirements and Environmental Laws and Regulations within Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations. Human Capital Management Our company fulfills a critical role in the nation's electric utility infrastructure. In order to do so, we believe we need to attract, retain, motivate and develop a high quality, diverse workforce and provide a safe, inclusive and productive work environment for everyone. Our company's core values are teamwork, transparency, respect, integrity, public service, and individual safety and well-being. Our company's core beliefs are unleash potential, live safely, achieve together, create shared trust, value diversity and inclusion, take charge and values matter. We believe that our company's values and beliefs serve as a foundation for our relationships with our employees, who we refer to internally as members of the Registrants. These core values and beliefs are reinforced to all employees at the time of hire, annually through a review of our Code of Ethics and periodically through small and large group meetings. We believe the efforts described herein, among others, contribute to our members' sense of purpose for the work we perform and result in the retention of our members. This belief is supported by OGE Energy being named by Forbes as the #2 Best Employer in Oklahoma for 2022 based on safety of work environment, competitiveness of compensation, opportunities for advancement, openness to telecommuting and how likely members would be to recommend OGE Energy as an employer. At December 31, 2022, OGE Energy had 2,237 employees, of which 1,861 are OGE employees. Total Rewards To help us attract and retain the most qualified individuals for our businesses, we provide a combination of strong compensation and comprehensive benefit offerings, including healthcare, health savings and flexible spending accounts, short-term and long-term incentive plans, retirement savings plans with company matching contributions, disability coverage, paid time off, parental leave and employee assistance programs. We also have a defined benefit pension plan that covers certain employees hired on or before December 1, 2009. Our employees are also offered two days of paid volunteer leave every year, which is intended to further enrich both their lives and the lives of others in the communities we serve. Employee Recruiting, Development and Engagement We make it a priority to attract, retain, motivate and develop a high-quality workforce. Our recruitment efforts begin with industry and career awareness efforts directed toward learning institutions, parents and students. We have built partnerships with universities, state career tech systems, state education departments, technical learning/trade schools, military bases and local school districts to increase awareness of the employment opportunities we provide and the total rewards packages that are tied to those opportunities. We build these relationships to create talent pipelines that will funnel qualified individuals back to our organization and the workforce needs we have identified. We provide our employees with a variety of opportunities for career growth and development. Many of the positions in our company are highly specialized, so having appropriate training and succession planning is critical to business continuity and competitiveness. We provide leadership, career development and skill-building opportunities, including internal and external training as well as tuition reimbursement, to invest in the next generation of leaders for our company. The number of annual hours of training per employee that we target, and historically average, aligns with the benchmark published annually by the American Society of Training and Development. OGE Energy, like many utilities across the country, is planning for and managing the effects of turnover of our workforce due to a significant number of retirements occurring now and expected during the next five to ten years, which is a period that will be impacted by major transformation of our business through technology investments, regulatory changes to our electric generation portfolio and upgrades to our distribution infrastructure. Management engages in ongoing succession planning discussions, which includes the annual involvement of OGE Energy's Board of Directors as it relates to officer succession planning. OGE Energy conducts and/or participates in employee engagement surveys to seek feedback from its employees on a variety of topics, including understanding of and alignment with the company's strategy, objectives, values and beliefs, management practices, operational performance and the employee value proposition. OGE Energy shares the survey results with employees, and senior management incorporates the results of the surveys into their action plans in order to respond to the feedback and further enhance employee engagement. Safety At OGE Energy, safety is more than a priority; it is a value and is paramount in the work we perform. Our safety principles are core to who we are and what we do. These principles are communicated, demonstrated and embraced at all levels of the company and supported by our core belief to Live Safely. To us, Live Safely means we protect ourselves and others from injury by constant engagement, always living safely. Our goal is to have zero safety incidents every year, and we educate all employees on our incident and injury-free workplace vision through extensive training on safety culture and task specific training to perform their work safely. To further our vision of safety excellence, our health and safety professionals, supervisors and Safety Task Force teams conduct routine work observations to verify employees and contractors are following safety protocols and procedures and provide coaching, if necessary. To further drive improvements in our safety performance, we report and analyze all near misses and incidents to understand the causal factors and associated corrective actions necessary to reduce the likelihood of recurrence. We share what we have learned company-wide to provide real-time learning opportunities for all employees. We continue to analyze trends and engage in discussions with our employees, creating a dialogue to enhance safety performance and work toward our incident and injury-free workplace. Our focus on safety has contributed to each of the last seven years being the safest in our 120-year history. Since the inception of our safety principle that all incidents and injuries are preventable and embracing our incident and injury free vision, we have seen a sustained decline in our injury rate. We have reduced our 5-year averages for OSHA recordable injuries by 73 percent and our Days Away, Restricted, Transfer Rate (DART) by 78 percent since our 2011 baseline. The DART rate is an OSHA calculation that determines how safe businesses have been in a calendar year in reference to particular types of worker compensation injuries. OGE is subject to a number of federal, state and local regulations, which are administered by a variety of agencies. These agencies cover areas such as health and safety, transportation and the environment. OGE has processes and procedures for these areas, and we believe we are in material compliance with all applicable regulations. Diversity and Inclusion Within our overall recruitment efforts, we are focused on diversity with the over-arching goal for the company's workforce to look like the communities we serve. Several of the talent pipeline partnerships referenced above are with organizations and trade schools whose student populations are diverse or raised in underrepresented communities. The company continues working with others to recruit diverse students to their programs, which can lead to potential employment for our positions. We have also formed relationships with universities to provide scholarships to students with diverse backgrounds and have focused on hiring individuals transitioning out of the military. For our workforce as a whole, the hiring percentage of members representing gender, racial and ethnically diverse communities has been trending upward for the past three years, and we expect that trend to continue. The retirement of our more tenured employees creates opportunities to promote or attract and hire additional individuals with diverse backgrounds. We strive to reinforce the belief that our members are one of our greatest assets by creating a culture of respect throughout the company. One of our core beliefs is to Value Diversity and Inclusion, which to us means that we embrace the uniqueness of each individual to make us a stronger and more resourceful organization, which enables us to serve and support the diverse communities where we live and work. We do this by, among other things, encouraging employees to treat others justly and considering their views in the decisions we make. The company currently has eight employee-led Member Resource Groups (MRGs) supporting Asian American Pacific Islander, Black, Hispanic, LGBTQ+, Veteran and Women members along with new members and those dedicated to public service. All groups are voluntary and inclusive. Each MRG selects an officer of the company to serve as its Executive Sponsor. These MRGs are intended to foster a sense of belonging for all employees, inspire conversation, introduce new ways of thinking about issues, drive innovation among our diverse population of members and provide an opportunity for professional development, community involvement and recruitment. Information About the Registrants' Executive Officers The following table presents the names, titles and business experience for the most recent five years for those persons serving as Executive Officers of the Registrants as of February 22, 2023: ##TABLE_START Name Age Current Title and Business Experience Sean Trauschke 2018 - Present: Chairman of the Board, President and Chief Executive Officer of OGE Energy Corp. W. Bryan Buckler 2021 - Present: Chief Financial Officer of OGE Energy Corp. 2019 - 2020: Vice President of Investor Relations - Duke Energy Corporation 2018 - 2019: Director of Financial Planning and Analysis - Duke Energy Corporation Sarah R. Stafford 2018 - Present: Controller and Chief Accounting Officer of OGE Energy Corp. 2018: Accounting Research Officer of OGE Energy Corp. Scott A. Briggs 2020 - Present: Vice President - Human Resources of OGE 2019 - 2020: Managing Director Human Resources of OGE 2018: Chief Operating Officer of The Oklahoma Publishing Co., d/b/a The Oklahoma Media Company Robert J. Burch 2020 - Present: Vice President - Utility Technical Services of OGE 2018 - 2020: Managing Director Utility Technical Services of OGE 2018: Director Power Supply Services of OGE Andrea M. Dennis 2019 - Present: Vice President - Transmission and Distribution Operations of OGE 2019: Managing Director Transmission and Distribution Operations of OGE 2018 - 2019: Director System Operations of OGE Keith E. Erickson 2022 - Present: Vice President - Sales and Customer Operations of OGE 2018 - 2022: Director of Sales and Business Development of OGE Donnie O. Jones 2019 - Present: Vice President - Utility Operations of OGE 2018 - 2019: Vice President - Power Supply Operations of OGE Cristina F. McQuistion 2020 - Present: Vice President - Corporate Responsibility and Stewardship of OGE Energy Corp. 2018 - 2020: Vice President - Chief Information Officer of OGE Kenneth A. Miller 2019 - Present: Vice President - Public and Regulatory Affairs of OGE 2018: State Treasurer of Oklahoma David A. Parker 2020 - Present: Vice President - Technology, Data and Security of OGE 2019 - 2020: Director Enterprise Security Risk of OGE Energy Corp. 2018 - 2019: Director of Internal Audit of OGE Energy Corp. Matthew J. Schuermann 2020 - Present: Vice President - Power Supply Operations of OGE 2019 - 2020: Managing Director Power Plant Operations of OGE 2018 - 2019: Special Projects Director of OGE William H. Sultemeier 2022 - Present: General Counsel, Corporate Secretary and Chief Compliance Officer of OGE Energy Corp. 2018 - 2022: General Counsel and Chief Compliance Officer of OGE Energy Corp. Charles B. Walworth 2018 - Present: Treasurer of OGE Energy Corp. Johnny W. Whitfield, Jr. 2022 - Present: Vice President - Business Intelligence and Supply Chain of OGE 2019 - 2022: Director of Business Intelligence of OGE 2018 - 2019: Sr. Manager of Resource Coordination of OGE Christine O. Woodworth 2021 - Present: Vice President - Marketing and Communications of OGE 2018 - 2021: Vice President of Public Relations - Sonic Drive-In, a fast-food restaurant chain ##TABLE_END No family relationship exists between any of the Executive Officers of the Registrants. Messrs. Trauschke, Buckler, Sultemeier, Walworth and Mses. McQuistion and Stafford are also officers of OGE. Each Executive Officer is to hold office until the next annual election of officers by the Board of Directors which is typically accomplished at the first regular board meeting following the Annual Meeting of Shareholders, currently scheduled for May 18, 2023. Item 1A. Risk Factors. In the discussion of risk factors set forth below, unless the context otherwise requires, the terms we, our and us refer to the Registrants. In addition to the other information in this Form 10-K and other documents filed by us and/or our subsidiaries with the Securities and Exchange Commission from time to time, the following factors should be carefully considered in evaluating OGE Energy and its subsidiaries. Such factors could affect actual results and cause results to differ materially from those expressed in any forward-looking statements made by or on behalf of us or our subsidiaries. Additional risks and uncertainties not currently known to us or that we currently view as immaterial may also impair our business operations. The Registrants are subject to a variety of risks which can be classified as regulatory, operational, financial and general. Risk factors of OGE are also risk factors of OGE Energy. REGULATORY RISKS The Registrants' profitability depends to a large extent on the ability of OGE to fully recover its costs, including its cost of capital, from its customers in a timely manner, and there may be changes in the regulatory environment that impair its ability to recover costs from its customers. OGE is subject to comprehensive regulation by several federal and state utility regulatory agencies, which significantly influences its operating environment and its ability to fully recover its costs, including its cost of capital, from utility customers. Recoverability of any under recovered amounts from OGE's customers due to a rise in fuel costs is a significant risk, such as the Oklahoma and Arkansas fuel clause under recovery amounts as disclosed in Note 1 within Item 8. Financial Statements and Footnotes. The utility commissions in the states where OGE operates regulate many aspects of its electric operations including siting and construction of facilities, customer service and the rates that OGE can charge customers. The profitability of the electric operations is dependent on OGE's ability to fully recover costs related to providing electricity and power services to its customers in a timely manner. Any failure to obtain utility commission approval to increase rates to fully recover costs, or a delay in the receipt of such approval, could have an adverse impact on OGE's results of operations. In addition, OGE's jurisdictions have fuel adjustment clauses that permit OGE to recover fuel and purchased power costs through rates without a general rate review, subject to a later determination that such costs were prudently incurred. If the state regulatory commissions determine that such costs were not prudently incurred, recovery could be disallowed. In recent years, the regulatory environments in which OGE operates have received an increased amount of attention. It is possible that there could be changes in the regulatory environment that would impair OGE's ability to fully recover costs historically paid by OGE's customers. State utility commissions generally possess broad powers to ensure that the needs of the utility customers are being met. OGE cannot assure that the OCC, APSC and the FERC will grant rate increases in the future or in the amounts requested, and they could instead lower OGE's rates. The Registrants are unable to predict the impact on their operating results from future regulatory activities of any of the agencies that regulate OGE. Changes in regulations, legislation or the imposition of additional regulations or legislation could have an adverse impact on the Registrants' results of operations. OGE's rates are subject to rate regulation by the states of Oklahoma and Arkansas, as well as by a federal agency, whose regulatory paradigms and goals may not be consistent. OGE is a vertically integrated electric company. Most of its revenue results from the sale of electricity to retail customers subject to bundled rates that are approved by the applicable state utility commission. OGE operates in Oklahoma and western Arkansas and is subject to rate regulation by the OCC and the APSC, in addition to FERC regulation of its transmission activities and any wholesale sales. Exposure to inconsistent state and federal regulatory standards may limit our ability to operate profitably. Further alteration of the regulatory landscape in which we operate, including a change in our authorized return on equity, may harm our financial position and results of operations. Costs of compliance with environmental laws and regulations are significant, and the cost of compliance with future environmental laws and regulations may adversely affect our results of operations, financial position or liquidity. We are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, wildlife conservation, natural resources and health and safety that could, among other things, restrict or limit the output of certain facilities or the use of certain fuels required for the production of electricity and/or require additional pollution control equipment and otherwise increase costs. There are significant capital, operating and other costs associated with compliance with these environmental statutes, rules and regulations and those costs may be even more significant in the future. In response to recent regulatory and judicial decisions and international accords, emissions of greenhouse gases including, most significantly, CO_2, could be restricted in the future as a result of federal or state legal requirements or litigation relating to greenhouse gas emissions. No rules are currently in effect that require us to reduce our greenhouse gas emissions, but laws and regulations to which we must adhere change, and the Biden Administration's agenda includes a significant shift in environmental and energy policy, focusing on reducing greenhouse gas emissions and addressing climate change issues. Together, these actions reflect climate change issues and greenhouse gas emission reductions as central areas of focus for domestic and international regulations, orders and policies. In addition, a parallel focus on reducing greenhouse gas emissions is reflected in legislation introduced in Congress. For example, the Infrastructure Investment and Jobs Act and Inflation Reduction Act were passed into law in 2022. These laws present opportunities for federal grants and tax incentives intended to hasten the future economy-wide deployment of various greenhouse gas emission reducing technologies and approaches. These initiatives could lead to new and revised energy and environmental laws and regulations, including tax reforms relating to energy and environmental issues. Any such changes, as well as any enforcement actions or judicial decisions regarding those laws and regulations, could result in significant additional compliance costs that would affect our future financial position, results of operations and cash flows if such costs are not recovered through regulated rates. Such changes also could affect the manner in which we conduct our business and could require us to make substantial additional capital expenditures or abandon certain projects. There is inherent risk of the incurrence of environmental costs and liabilities in our operations and historical industry practices. These activities are subject to stringent and complex federal, state and local laws and regulations that can restrict or impact OGE's business activities in many ways, such as restricting the way OGE can handle or dispose of its wastes or requiring remedial action to mitigate pollution conditions that may be caused by its operations or that are attributable to former operators. OGE may be unable to recover these costs from insurance or other regulatory mechanisms. The Biden Administration has suggested that it will enact stricter laws, regulations and enforcement policies that could significantly increase compliance costs and the cost of any remediation that may become necessary. If regulations are enacted regarding any of our generating units, as listed in Item 2. Properties, it could potentially result in stranded assets. In addition, we may be required to make significant expenditures in connection with the investigation and remediation of alleged or actual spills, personal injury or property damage claims, and the repair, upgrade or expansion of our facilities to meet future requirements and obligations under environmental laws. For further discussion of environmental matters that may affect the Registrants, see Environmental Laws and Regulations within Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations. We are subject to financial risks associated with climate change and the transition to a lower carbon economy. In addition to the potential for physical risk related to climate change (discussed below), climate change, and the risks related to our transition to a lower-carbon economy, creates financial risk. Transition risks represent those risks related to the social and economic changes needed to shift toward a lower carbon future. These risks are often interconnected, representing policy and regulatory changes, technology and market risks, and risks to our reputation and financial performance. Potential regulation associated with climate change legislation could pose financial risks to OGE Energy and its affiliates. The U.S. is a party to the United Nations' Paris Agreement on climate change, and the Agreement along with other potential legislation and regulation discussed above, could result in enforceable greenhouse gas emission reduction requirements that could lead to increased compliance costs for OGE Energy and its affiliates. For example, in September 2022, the EPA created a non-rulemaking docket for public input related to the EPA's efforts to reduce emissions of greenhouse gases from new and existing fossil fuel-fired electric generating units under the Clean Air Act Section 111. As we expand our cleaner energy generation asset mix, the ability to integrate renewable technologies into our operations and maintain reliability and affordability is key. The intermittency of renewables remains a critical challenge particularly as cost-efficient energy storage is still in development. Other technology risks include the need for significant upfront financial investments, lengthy development timelines, and the uncertainty of integration and scalability across our entire service territory. In addition, to the extent that any climate change adversely affects the national or regional economic health through physical impacts or increased rates caused by the inclusion of additional regulatory costs, CO_2 taxes or imposed costs, OGE Energy and its affiliates may be adversely impacted. There are also increasing risks for energy companies from shareholders currently invested in fossil-fuel energy companies concerned about the potential effects of climate change who may elect in the future to shift some or all of their investments into entities that emit lower levels of greenhouse gases or into non-energy related sectors. Institutional investors and lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable investing and lending practices and some of them may elect not to provide funding for fossil fuel energy companies. To the extent financial markets view climate change and emissions of greenhouse gases as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less than ideal terms and conditions. In addition, we may be subject to financial risks from private party litigation relating to greenhouse gas emissions. Defense costs associated with such litigation can be significant and an adverse outcome could require substantial capital expenditures and could possibly require payment of substantial penalties or damages. Such payments or expenditures could affect results of operations, financial condition or cash flows if such costs are not recovered through regulated rates. We may not be able to recover the costs of our substantial investments in capital improvements and additions. Our business plan calls for extensive investments in capital improvements and additions in OGE, including modernizing existing infrastructure as well as other initiatives. Significant portions of OGE's facilities were constructed many years ago. Older generation equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to maintain efficiency, to comply with environmental requirements or to provide reliable operations. As discussed above, the Infrastructure Investment and Jobs Act and Inflation Reduction Act present opportunities for federal grants and tax incentives intended to hasten the future economy-wide deployment of various greenhouse gas emission reducing technologies and approaches. While we plan to pursue opportunities through the Infrastructure Investment and Jobs Act, we expect to typically be responsible for 50 percent of the dollars spent on investments related to this Act. OGE currently provides service at rates approved by one or more regulatory commissions. If these regulatory commissions do not approve adjustments to the rates OGE charges, it would not be able to recover the costs associated with its planned extensive investment. This could adversely affect the Registrants' financial position and results of operations. While OGE may seek to limit the impact of any denied recovery by attempting to reduce the scope of its capital investment, there can be no assurance as to the effectiveness of any such mitigation efforts, particularly with respect to previously incurred costs and commitments. The regional power market in which OGE operates has changing transmission regulatory structures, which may affect the transmission assets and related revenues and expenses. OGE currently owns and operates transmission and generation facilities as part of a vertically integrated utility. OGE is a member of the SPP regional transmission organization and has transferred operational authority (but not ownership) of OGE's transmission facilities to the SPP. The SPP has implemented regional day ahead and real-time markets for energy and operating reserves, as well as associated transmission congestion rights. Collectively, the three markets operate together under the global name, SPP Integrated Marketplace. OGE represents owned and contracted generation assets and customer load in the SPP Integrated Marketplace for the sole benefit of its customers. OGE has not participated in the SPP Integrated Marketplace for any speculative trading activities. Our revenues, expenses, assets and liabilities may be adversely affected by changes in the organization, operation and regulation of the SPP Integrated Marketplace by the FERC or the SPP. Increased competition resulting from efforts to restructure utility and energy markets or deregulation could have a significant financial and load growth impact on us and consequently impact our revenue and affordability of services. We have been and will continue to be affected by competitive changes to the utility and energy industries. Significant changes have occurred and additional changes have been proposed to the wholesale electric market. Retail competition and the unbundling of regulated energy service could have a significant financial impact on us due to possible impairments of assets, a loss of retail customers, impact profit margins and/or increased costs of capital. Further, we regularly engage in negotiations on renewals of franchise agreements with municipal governments within our service territories. Any such restructuring could have a significant impact on our financial position, results of operations and cash flows. Further, our load growth could be impacted, which could result in an impact on the affordability of our services. We cannot predict when we will be subject to changes in legislation or regulation, nor can we predict the impact of these changes on our financial position, results of operations or cash flows. We are subject to substantial utility regulation by governmental agencies. Compliance with current and future utility regulatory requirements and procurement of necessary approvals, permits and certifications may result in significant costs to us. We are subject to substantial regulation from federal, state and local regulatory agencies. We are required to comply with numerous laws and regulations and to obtain permits, approvals and certifications from the governmental agencies that regulate various aspects of our businesses, including customer rates, service regulations, retail service territories, sales of securities, asset acquisitions and sales, accounting policies and practices and the operation of generating facilities. We believe the necessary permits, approvals and certificates have been obtained for our existing operations and that our business is conducted in accordance with applicable laws; however, we are unable to predict the impact on our operating results from future regulatory activities of these agencies. The NERC is responsible for the development and enforcement of mandatory reliability and cyber security standards for the wholesale electric power system. OGE's plan is to comply with all applicable standards and to expediently correct a violation should it occur. As one of OGE's regulators, the NERC has comprehensive regulations and standards related to the reliability and security of our operating systems and is continuously developing additional mandatory compliance requirements for the utility industry. The increasing development of NERC rules and standards will increase compliance costs and our exposure for potential violations of these standards. OPERATIONAL RISKS Our results of operations may be impacted by disruptions to fuel supply or the electric grid that are beyond our control. We are exposed to risks related to performance of contractual obligations by our suppliers and transporters. We are dependent on coal and natural gas for much of our electric generating capacity. We rely on suppliers to deliver coal and natural gas in accordance with short- and long-term contracts. We have certain supply and transportation contracts in place; however, there can be no assurance that the counterparties to these agreements will fulfill their obligations to supply and transport coal and natural gas to us. The suppliers and transporters under these agreements may experience financial or technical problems that inhibit their ability to fulfill their obligations to us. In addition, the suppliers and transporters under these agreements may not be required to provide the commodity or service under certain circumstances, such as in the event of a natural disaster. Deliveries may be subject to short-term interruptions or reductions due to various factors, including transportation problems, weather, availability of equipment and labor shortages. Failure or delay by our suppliers and transporters of coal and natural gas could disrupt our ability to deliver electricity and require us to incur additional expenses to meet the needs of our customers. Also, because our generation and transmission systems are part of an interconnected regional grid, we face the risk of possible loss of business due to a disruption or black-out caused by an event such as a severe storm, generator or transmission facility outage on a neighboring system or the actions of a neighboring utility. Any such disruption could result in a significant decrease in revenues and significant additional costs to repair assets, which could have a material adverse impact on our financial position, results of operations and cash flows. OGE's electric generation, transmission and distribution assets are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses, increased purchased power costs, accidents and third-party liability. OGE owns and operates coal-fired, natural gas-fired, wind-powered and solar-powered generating assets. Operation of electric generation, transmission and distribution assets involves risks that can adversely affect energy output and efficiency levels or that could result in loss of human life, significant damage to property, environmental pollution and impairment of OGE's operations. Included among these risks are: increased prices for fuel, fuel transportation, purchased power and purchased capacity as existing contracts expire; facility shutdowns due to a breakdown or failure of equipment or processes or interruptions in fuel supply; operator error or safety related stoppages; disruptions in the delivery of electricity; intentional destruction of electric grid equipment; and catastrophic events such as fires, explosions, tornadoes, floods, earthquakes or other similar occurrences. The occurrence of any of these events, if not fully covered by insurance or if insurance is not available, could have a material effect on our financial position and results of operations. Further, when unplanned maintenance work is required on power plants or other equipment, OGE will not only incur unexpected maintenance expenses, but it may also have to make spot market purchases of replacement electricity that could exceed OGE's costs of generation or be forced to retire a generation unit if the cost or timing of the maintenance is not reasonable and prudent. If OGE is unable to recover any of these increased costs in rates, it could have a material adverse effect on our financial performance. Changes in technology, regulatory policies and customer electricity consumption may cause our assets to be less competitive and impact our results of operations. OGE is a vertically integrated electric company and primarily generates electricity at large central facilities. We believe this method is the most efficient and cost-effective method for power delivery, as it typically results in economies of scale and lower costs than newer technologies such as fuel cells, microturbines, wind turbines and photovoltaic solar cells. It is possible that advances in technologies or changes in regulatory policies will reduce costs of new technology to levels that are equal to or below that of most central station electricity production, which could have a material adverse effect on our results of operations. OGE's widespread use of Smart Grid technology allowing for two-way communications between the electric company and its customers could enable the entry of technology companies into the interface between OGE and its customers, resulting in unpredictable effects on our current business. Reductions in customer electricity consumption, thereby reducing utility electric sales, could result from increased deployment of renewable energy technologies as well as increased efficiency of household appliances, among other general efficiency gains in technology. However, this potential reduction in load would not reduce our need for ongoing investments in our infrastructure to reliably serve our customers. Continued utility infrastructure investment without increased electricity sales could cause increased rates for customers, potentially resulting in further reductions in electricity sales and reduced profitability. Weather conditions such as tornadoes, thunderstorms, ice storms, wind storms, flooding, earthquakes, prolonged droughts and the occurrence of wildfires, as well as seasonal temperature variations may adversely affect our financial position, results of operations and cash flows. Weather conditions directly influence the demand for electric power. In OGE's service area, demand for power peaks during the hot summer months, with market prices also typically peaking at that time. As a result, overall operating results may fluctuate on a seasonal and quarterly basis. In addition, we have historically sold less power, and consequently received less revenue, when weather conditions are milder. Unusually mild weather in the future could reduce our revenues, net income, available cash and borrowing ability. Severe weather, such as tornadoes, thunderstorms, ice storms, wind storms, flooding, earthquakes, prolonged droughts and the occurrence of wildfires, may cause outages and property damage which may require us to incur additional costs that are generally not insured and that may not be recoverable from customers. The effect of the failure of our facilities to operate as planned, as described above, would be particularly burdensome during a peak demand period. In addition, prolonged droughts could cause a lack of sufficient water for use in cooling during the electricity generating process.

Physical risks from climate can be considered in both acute (event-driven) and chronic (longer-term shifts in climate patterns) terms. The effects of climate change could exacerbate physical changes in weather and the extreme weather events discussed above, including prolonged droughts, rise in temperatures and more extreme weather events like wildfires and ice storms, among other weather impacts. We have observed some of these events in recent years, and the trend could continue. OGE can incur significant restoration costs as a result of these weather events. If OGE is unable to recover any of these increased costs in rates, it could have a material adverse effect on our financial performance. FINANCIAL RISKS Market performance, increased retirements, changes in retirement plan regulations and increasing costs associated with our Pension Plan, health care plans and other employee-related benefits may adversely affect our financial position, results of operations or cash flows. We have a Pension Plan that covers certain employees hired before December 1, 2009. We also have defined benefit postretirement plans that cover certain employees hired prior to February 1, 2000. Assumptions related to future costs, returns on investments, interest rates and other actuarial assumptions with respect to the defined benefit retirement and postretirement plans have a significant impact on our results of operations and funding requirements. We expect to make future contributions to maintain required funding levels as necessary, and it has been our practice to also make voluntary contributions to maintain more prudent funding levels than minimally required. We may continue to make voluntary contributions in the future. These amounts are estimates and may change based on actual stock market performance, changes in interest rates and any changes in governmental regulations. If the employees who participate in the Pension Plan retire when they become eligible for retirement over the next several years, or if our plan experiences adverse market returns on its investments, or if interest rates materially fall, our pension expense and contributions to the plans could rise substantially over historical levels. The timing and number of employees retiring and selecting the lump-sum payment option could result in pension settlement charges that could materially affect our results of operations if we are unable to recover these costs through our electric rates. In addition, assumptions related to future costs, returns on investments, interest rates and other actuarial assumptions, including projected retirements, have a significant impact on our financial position and results of operations. Those factors are outside of our control. In addition to the costs of our Pension Plan, the costs of providing health care benefits to our employees and retirees have increased in recent years. We believe that our employee benefit costs, including costs related to health care plans for our employees, will continue to rise. The increasing costs and funding requirements with our Pension Plan, health care plans and other employee benefits may adversely affect our financial position, results of operations or liquidity. OGE Energy is a holding company with its primary asset being its subsidiary, OGE. OGE Energy is a holding company and thus its primary asset is its subsidiary, OGE. Substantially all of OGE Energy's operations are conducted by its subsidiary. Consequently, OGE Energy's operating cash flow and its ability to pay dividends and service its indebtedness are dependent upon the operating cash flow of OGE and the payment of funds by OGE to OGE Energy in the form of dividends or distributions. At December 31, 2022, OGE Energy and OGE had outstanding indebtedness and other liabilities of $8.1 billion. OGE is a separate legal entity that has no obligation to pay any amounts due on OGE Energy's indebtedness or to make any funds available for that purpose, whether by dividends or distributions. In addition, OGE's ability to pay dividends or distributions to OGE Energy depends on any statutory and contractual restrictions that may be applicable to the entity, which may include requirements to maintain minimum levels of working capital and other assets. Claims of creditors, including general creditors, of OGE on its assets will generally have priority over OGE Energy claims (except to the extent that OGE Energy may be a creditor and its claims are recognized) and claims by OGE Energy shareholders. In addition, as discussed above, OGE is regulated by state utility commissions in Oklahoma and Arkansas as well as a federal regulatory agency which generally possess broad powers to ensure that the needs of the utility customers are being met. To the extent that the state commissions or federal regulatory agency attempt to impose restrictions on the ability of OGE to pay dividends to OGE Energy, it could adversely affect its ability to continue to pay dividends. GENERAL RISKS Governmental and market reactions to events involving other public companies or other energy companies that are beyond our control may have negative impacts on our business, financial position, results of operations, cash flows and access to capital. Accounting irregularities at public companies in general, and energy companies in particular, and investigations by governmental authorities into energy trading activities and political contributions, could lead to public and regulatory scrutiny and suspicion for public companies, including those in the regulated and unregulated utility business. Accounting irregularities could cause regulators and legislators to review current accounting practices, financial disclosures and relationships between companies and their independent auditors. The capital markets and rating agencies also could increase their level of scrutiny. We believe that we are complying with all applicable laws and accounting standards, but it is difficult or impossible to predict or control what effect any of these types of events may have on our business, financial position, cash flows or access to the capital markets. It is unclear what additional laws or regulations may develop, and we cannot predict the ultimate impact of any future changes in accounting regulations or practices in general with respect to public companies, the energy industry or our operations specifically. Any new accounting standards could affect the way we are required to record revenues, expenses, assets, liabilities and equity. These changes in accounting standards could lead to negative impacts on reported earnings or decreases in assets or increases in liabilities that could, in turn, affect our financial position, results of operations and cash flows. Economic conditions, including inflationary pressures and supply chain disruptions, could negatively impact our business and our results of operations. Our operations have been and are affected by local, national and worldwide economic conditions. National and global events could adversely affect and/or exacerbate macroeconomic conditions, including inflationary pressures, rising interest rates, supply chain disruptions and economic recessions, which in turn affect our operations and our customers. The Registrants have experienced rising costs to produce electricity through increased fuel prices, raw material inflation, logistical challenges and certain component shortages. We are dependent upon others, such as fuel suppliers and transporters and suppliers for our capital projects, to help execute our operations. Supply chain disruption has resulted, and may continue to result, in delays in construction activities and equipment deliveries related to our capital projects. The consequences of a recession could include a lower level of economic activity and uncertainty regarding energy prices and the capital and commodity markets. A lower level of economic activity and general inflation could result in a decline in energy consumption, which could adversely affect our revenues and future growth. Instability in the financial markets, as a result of recession or otherwise, also could affect the cost of capital and our ability to raise capital. Economic conditions may also impact the valuation of certain long-lived assets that are subject to impairment testing, potentially resulting in impairment charges, which could have a material adverse impact on our results of operations. Economic conditions may be impacted by insufficient financial sector liquidity leading to potential increased unemployment, which could impact the ability of our customers to pay timely, increase customer bankruptcies, and could lead to increased bad debt. If such circumstances occur, we expect that commercial and industrial customers would be impacted first, with residential customers following. In addition, economic conditions, particularly budget shortfalls, could increase the pressure on federal, state and local governments to raise additional funds by increasing corporate tax rates and/or delaying, reducing or eliminating tax credits, grants or other incentives that could have a material adverse impact on our results of operations and cash flows. We are subject to cybersecurity risks and increased reliance on processes dependent on technology. In the regular course of our business, we handle a range of sensitive security and customer information. We are subject to laws and rules issued by different agencies concerning safeguarding and maintaining the confidentiality of this information. A security breach of our information systems due to theft, ransomware, viruses, denial of service, hacking, acts of war or terrorism or inappropriate release of certain types of information, including confidential customer information or system operating information, could have a material adverse impact on our financial position, results of operations and cash flows. OGE operates in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. Despite implementation of security measures, the technology systems are vulnerable to disability, failures or unauthorized access. Such failures or breaches of the systems could impact the reliability of OGE's generation, transmission and distribution systems which may result in a loss of service to customers and also subject OGE to financial harm due to the significant expense to respond to security breaches or repair system damage. Our generation and transmission systems are part of an interconnected system. Therefore, a disruption caused by the impact of a cybersecurity incident of the regional electric transmission grid, natural gas pipeline infrastructure or other fuel sources of our third-party service providers' operations could also negatively impact our business. If the technology systems were to fail or be breached and not recovered in a timely manner, critical business functions could be impaired and sensitive confidential data could be compromised, which could have a material adverse impact on our financial position, results of operations and cash flows. Security threats continue to evolve and adapt. We and our third-party vendors have been subject to, and will likely continue to be subject to, attempts to gain unauthorized access to systems, or confidential data, or to disrupt operations. None of these attempts has individually or in aggregate resulted in a security incident with a material impact on our financial condition or results of operations. Despite implementation of security and control measures, there can be no assurance that we will be able to prevent the unauthorized access of our systems and data, or the disruption of our operations, either of which could have a material impact. Our security procedures, which include among others, virus protection software, cybersecurity controls and monitoring and our business continuity planning, including disaster recovery policies and back-up systems, may not be adequate or implemented properly to fully address the adverse effect of cybersecurity attacks on our systems, which could adversely impact our operations. We maintain property, casualty and cybersecurity insurance that may cover certain resultant cyber and physical damage or third-party injuries caused by potential cyber events. However, damage and claims arising from such incidents may exceed the amount of any insurance available and other damage and claims arising from such incidents may not be covered at all. For these reasons, a significant cyber incident could reduce future net income and cash flows and impact financial condition. The failure of our technology infrastructure, or the failure to enhance existing technology infrastructure and implement new technology, could adversely affect our business. Our operations are dependent upon the proper functioning of our internal systems, including the technology and network infrastructure that support our underlying business processes. Any significant failure or malfunction of such technology infrastructure may result in disruptions of our operations. In the ordinary course of business, we rely on technology infrastructure, including the internet and third-party hosted services, to support a variety of business processes and activities and to store sensitive data. Our technology infrastructure is dependent upon global communications and cloud service providers, as well as their respective vendors, many of whom have at some point experienced significant system failures and outages in the past and may experience such failures and outages in the future. These providers' systems are susceptible to cybersecurity and data breaches, outages from fire, floods, power loss, telecommunications failures, physical attack and similar events. Failure to prevent or mitigate data loss from system failures or outages could materially adversely affect our results of operations, financial position and cash flows. In addition to maintaining our current technology infrastructure, we believe the digital transformation of our business is key to driving internal efficiencies as well as providing additional capabilities to customers. Our technology infrastructure is critical to cost-effective, reliable daily operations and our ability to effectively serve our customers. We expect our customers to continue to demand more sophisticated technology-driven solutions, and we must enhance or replace our technology infrastructure in response. This involves significant development and implementation costs to keep pace with changing technologies and customer demand. If we fail to successfully implement critical technology infrastructure, or if it does not provide the anticipated benefits or meet customer demands, such failure could materially adversely affect our business strategy as well as impact our results of operations, financial position and cash flows. Terrorist attacks, and the threat of terrorist attacks, have resulted in increased costs to our business and could impact our ability to operate critical infrastructure. Continued hostilities or sustained military campaigns may adversely impact our financial position, results of operations and cash flows. In late 2022, physical attacks on electric equipment owned by other electric utility companies in the U.S. resulted in the loss of power for a period of time. Authorities have indicated they believe these attacks may have been carried out by domestic extremists, as the U.S. electric grid is noted as being highly vulnerable to domestic terrorism. While the Registrants have experienced physical attacks on their electric equipment, these incidents have not been material to their operations. The long-term impact of terrorist attacks and the magnitude of the threat of future terrorist attacks on the electric utility in general, and on us in particular, cannot be known. Increased security measures taken by us as a precaution against possible terrorist attacks have resulted in increased costs to our business. Uncertainty surrounding continued hostilities or sustained military campaigns may affect our operations in unpredictable ways, including disruptions of supplies and markets for our products, and the possibility that our infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror. Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than existing insurance coverage. Health epidemics and other outbreaks could adversely impact economic activity and conditions worldwide, which could have a material adverse effect on our results of operations and financial condition. Health epidemics and other outbreaks, such as the COVID-19 pandemic, could adversely impact economic activity and conditions worldwide, by, among other things, leading to shutdowns, disrupting supply chains, increasing unemployment, resulting in customer slow payment or non-payment and decreasing commercial and industrial load. In response to health epidemics and other outbreaks, an extended slowdown of the United States' economic growth, demand for commodities and/or material changes in governmental policy could result in lower economic growth and lower demand for electricity in our key markets as well as the ability of various customers, contractors, suppliers and other business partners to fulfill their obligations, which could have a material adverse effect on our results of operations, financial condition and prospects. We face certain human resource risks associated with the availability of trained and qualified labor to meet our future staffing requirements. Workforce demographic issues challenge employers nationwide and are of particular concern to the electric utility industry. The median age of utility workers is higher than the national average. Over the next three years, 23.4 percent of our current employees will meet the eligibility requirements to retire. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, may adversely affect our ability to manage and operate our business. We may be able to incur substantially more indebtedness, which may increase the risks created by our indebtedness. The terms of the indentures governing our debt securities do not fully prohibit OGE Energy or OGE from incurring additional indebtedness. If we are in compliance with the financial covenants set forth in our revolving credit agreements and the indentures governing our debt securities, we may be able to incur substantial additional indebtedness. If we incur additional indebtedness, the related risks that we now face may intensify. Any reductions in our credit ratings or changes in benchmark interest rates could increase our financing costs and the cost of maintaining certain contractual relationships or limit our ability to obtain financing on favorable terms. We cannot assure you that any of the current credit ratings of the Registrants will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. Our ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade or major market disruptions. Pricing grids associated with our credit facilities could cause annual fees and borrowing rates to increase if an adverse rating impact occurs. The impact of any future downgrade could include an increase in the costs of our short-term borrowings, but a reduction in our credit ratings would not result in any defaults or accelerations. Any future downgrade could also lead to higher long-term borrowing costs and, if below investment grade, would require us to post collateral or letters of credit. The Registrants recently amended their credit facilities to switch from eurodollar loans based on LIBOR to term SOFR loans. SOFR is a relatively new reference rate, and its composition and characteristics are not the same as LIBOR. It is not possible to predict what effect the change to SOFR may have on our interest rates. As indicated above, SOFR is a relatively new reference rate. Any failure of SOFR to gain market acceptance could cause the SOFR to be modified or discontinued. The Registrants' current credit facilities provide a mechanism for determining an alternative rate of interest upon the occurrence of certain events related to the discontinuance of SOFR. The change to SOFR or transition to other alternative rates, whether in connection with borrowings under the current credit facilities, or borrowings under replacement facilities or lines of credit, could expose the Registrants' future borrowings to less favorable rates. If the change to SOFR, or other alternative rates, results in increased alternative interest rates or if the Registrants' lenders have increased costs due to such phase out or changes, then the Registrants' debt that uses benchmark rates could be affected and, in turn, the Registrants' cash flows and interest expense could be adversely impacted. Our debt levels may limit our flexibility in obtaining additional financing and in pursuing other business opportunities. We have revolving credit agreements for working capital, capital expenditures, acquisitions and other corporate purposes. In December 2022, OGE Energy entered into an amendment to its revolving credit facility that increased the permitted maximum debt to capitalization ratio from 65 percent to 70 percent. OGEs credit facility has a financial covenant requiring it to maintain a maximum debt to capitalization ratio of 65 percent. The levels of our debt could have important consequences, including the following: the ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or the financing may not be available on favorable terms; a portion of cash flows will be required to make interest payments on the debt, reducing the funds that would otherwise be available for operations and future business opportunities; and our debt levels may limit our flexibility in responding to changing business and economic conditions. We are exposed to the credit risk of our key customers and counterparties, and any material nonpayment or nonperformance by our key customers and counterparties could adversely affect our financial position, results of operations and cash flows. We are exposed to credit risks in our generation and retail distribution operations. Credit risk includes the risk that counterparties who owe us money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected, and we could incur losses. We have seen increased interest for electric service from emerging industries such as crypto mining and hydrogen production, which are both large consumers of electricity. If this continues, these types of customers could represent a significant portion of our revenues.

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ITEM 1. BUSINESS ##TABLE_ENDOtter Tail Corporation (OTC) has interests in diversified operations that include an electric utility and manufacturing and plastic pipe businesses with corporate offices located in Fergus Falls, Minnesota and Fargo, North Dakota. We classify our five operating companies into three reportable segments consistent with our business strategy and management structure. The following table depicts our three segments and the subsidiary entities included within each segment: ##TABLE_START ELECTRIC SEGMENT MANUFACTURING SEGMENT PLASTICS SEGMENT Otter Tail Power Company (OTP) BTD Manufacturing, Inc. (BTD) Northern Pipe Products, Inc. (Northern Pipe) T.O. Plastics, Inc. (T.O. Plastics) Vinyltech Corporation (Vinyltech) ##TABLE_ENDElectric includes the generation, purchase, transmission, distribution and sale of electric energy in western Minnesota, eastern North Dakota and northeastern South Dakota. OTP, our largest operating subsidiary and primary business since 1907, serves more than 133,000 customers in more than 400 communities across a predominantly rural and agricultural service territory. Manufacturing consists of businesses in the following manufacturing activities: contract machining; metal parts stamping; fabrication and painting; and production of plastic thermoformed horticultural containers, life science and industrial packaging, material handling components and extruded raw material stock. These businesses have manufacturing facilities in Georgia, Illinois and Minnesota and sell products primarily in the United States. Plastics consists of businesses producing polyvinyl chloride (PVC) pipe at plants in North Dakota and Arizona. The PVC pipe is sold primarily in the western half of the United States and Canada. Throughout the remainder of this report, we use the terms "Company", "us", "our", or "we" to refer to OTC and its subsidiaries collectively. We will also refer to our Electric, Manufacturing and Plastics segments and our individual subsidiaries as indicated above. INVESTMENT AND GROWTH STRATEGY We maintain a moderate risk profile by investing in rate base growth opportunities in our Electric segment and organic growth opportunities in our Manufacturing and Plastics segments (collectively, our manufacturing platform). This strategy and risk profile are designed to provide a more predictable earnings stream, maintain our credit quality and preserve our ability to fund our dividend payments. Our long-term focus remains on executing our strategy to grow our business and achieving operational, commercial and talent excellence to strengthen our position in the markets we serve. We remain confident in our ability to achieve a compounded annual growth rate in earnings per share in the range of five to seven percent using 2024 as the base year. We currently expect to see elevated earnings per share from our manufacturing platform into 2023 with our earnings mix expected to move to approximately 65% from our Electric segment and 35% from our manufacturing platform beginning in 2024. We expect our earnings growth beyond 2024 to be driven by rate base investments in our Electric segment and from existing capacities and planned investments within our Manufacturing and Plastics segments. Over the past two years, we delivered earnings growth well in excess of our five to seven percent target due to unique industry conditions within the PVC pipe industry which led to extraordinary revenue, earnings and cash flow growth in our Plastics Segment. We will continue to review our business portfolio to identify additional opportunities to improve our risk profile, enhance our credit metrics and generate additional sources of cash to support the organic growth opportunities in our Electric, Manufacturing, and Plastics segments. We will also evaluate opportunities to allocate capital to potential acquisitions. We are a committed long-term owner and do not acquire companies in pursuit of short-term gains. However, we will divest businesses which no longer fit into our strategy and risk profile over the long term. We maintain a set of criteria used in evaluating the strategic fit of our operating businesses. The operating company should: Maintain a minimum level of net earnings and a return on invested capital in excess of the Companys weighted-average cost of capital, Have a strategic differentiation from competitors and a sustainable cost advantage, Operate within a stable and growing industry and be able to quickly adapt to changing economic cycles, and Have a strong management team committed to operational and commercial excellence. Our actual mix of earnings for the years ended December 31, 2022, 2021, and 2020 was as follows: HUMAN CAPITAL Our employees are a critical resource and an integral part of our success. We strive to provide an environment of opportunity and accountability where people are valued and empowered to do their best work. We are focused on the health and safety of our employees and creating a culture of inclusion, excellence and learning. Our human capital management efforts include monitoring various metrics and objectives associated with i) employee safety, ii) workforce stability, iii) management and workforce demographics, including gender, racial and ethnic diversity, iv) leadership development and succession planning and v) productivity. We have established the following programs in furtherance of these efforts: Safety - Safety is one of our core values. In managing our business, we focus on the safety of our employees and have implemented safety programs and management practices to promote a culture of safety. Safety is also a metric used and evaluated in determining annual incentive compensation. We continually monitor the Occupational Safety and Health Administration (OSHA) Total Recordable Incident Rate (number of work-related injuries per 100 employees for a one-year period) and Lost Time Incident Rate (number of employees who lost time due to work-related injuries per 100 employees for a one-year period). New cases are reported and evaluated for corrective action during monthly safety meetings attended by safety professionals at all locations. Our 2022 Total Recordable Incident Rate was 2.08, compared to 1.86 in 2021 and our Lost Time Incident Rate was 0.49, compared to 0.57 in 2021. In both 2022 and 2021 these rates were favorable when compared to the rates of our peers. Employee and Leadership Development, Succession Planning and Training Programs - We invest in leadership development for various levels of employees, management and leaders throughout the Company to build enterprise-wide understanding of our culture, strategy and processes. Annual succession planning, individual development planning, mentoring, and supervisory and leadership development programs all play a role in ensuring a capable leadership team now and in the future. Our skill progression and technical training programs help to retain a stable and skilled workforce. Workforce Stability - Recruiting, retaining and developing employees is an important factor in our continued success and growth. We regularly evaluate our recruiting programs, employee retention and turnover rates. Employee Engagement - To enhance the effectiveness of our workforce and to help our companies continue to be places where our employees choose to work and thrive, we have undertaken a multi-year series of employee engagement surveys. We use the feedback to help shape the employee programs of our organization. Diversity, Equity, and Inclusion - We expect, and are committed to, diversity, equity and inclusion as part of who we are, what we value and how we achieve individual, business and community success. We hold every employee accountable for their behavior in maintaining a workplace free of discrimination and harassment. We have implemented education initiatives for all employees, aimed at inclusive leadership and a respectful workplace, focused on identities and culture, unconscious bias, the power of diverse teams and culturally sensitive conversations. We have implemented initiatives to improve upon our demographic profile, including revised hiring processes and a commitment to diverse interview slates. Code of Business Ethics - We require employees to complete training on several topics associated with our code of business ethics to reinforce our commitment to compliance with laws, regulations and values that guide who we are and how we do business. As of December 31, 2022, we employed 2,422 full-time employees as shown in the table below: ##TABLE_START Segment/Organization Employees Electric Segment OTP (1) 728 Manufacturing Segment BTD 1,281 T.O. Plastics 204 Segment Total 1,485 Plastics Segment Northern Pipe 95 Vinyltech 78 Segment Total 173 Corporate 36 Total 2,422 (1) Includes all full-time employees of Otter Tail Power Company, including employees working at jointly-owned facilities. Labor costs associated with employees working at jointly-owned facilities are allocated to each of the co-owners based on their ownership interest. ##TABLE_ENDAt December 31, 2022, 354 employees of OTP were represented by local unions of the International Brotherhood of Electrical Workers under two separate collective bargaining agreements expiring on August 31, 2023 and October 31, 2023. OTP has not experienced any strike, work stoppage or strike vote, and considers its present relations with employees to be good. None of the employees of our other operating companies are represented by local unions. The demographics of our workforce, including our Board of Directors, as of December 31, 2022 was as follows: ##TABLE_START 2022 2021 % Female % Racially and Ethnically Diverse % Female % Racially and Ethnically Diverse Board of Directors (1) 36 % 9 % 20 % 10 % CEO Direct Reports 33 % % 33 % % Management 33 % 7 % 22 % 4 % Non-Management Employees 16 % 19 % 17 % 19 % (1) 2022 includes the new directors appointed to our Board effective January 1, 2023. ##TABLE_END##TABLE_START ELECTRIC Contribution to Operating Revenues: 38% (2022), 40% (2021), 50% (2020) ##TABLE_ENDOTP, headquartered in Fergus Falls, Minnesota, is a vertically integrated, regulated utility with generation, transmission and distribution facilities to serve its more than 133,000 residential, commercial and industrial customers in a service area encompassing approximately 70,000 square miles of western Minnesota, eastern North Dakota and northeastern South Dakota. CUSTOMERS Our service territory is predominantly rural and agricultural and includes over 400 communities, most of which have populations of less than 10,000. While our customer base includes relatively few large customers, sales to commercial and industrial customers are significant, with one industrial customer accounting for 11% and 10%, respectively, of segment operating revenues for the years ended December 31, 2022 and 2021. The following charts summarize our retail electric revenues by state and by customer segment for the years ended December 31, 2022 and 2021: In addition to retail revenue, our Electric segment also generates operating revenues from the transmission of electricity for others over the transmission assets we wholly or jointly own with other transmission service providers, and from the sale of electricity we generate and sell into the wholesale electricity market. COMPETITIVE CONDITIONS Retail electric sales are made to customers in assigned service territories. As a result, most retail customers do not have the ability to choose their electric supplier. Competition is present in some areas from municipally owned systems, rural electric cooperatives and, in certain respects, from on-site generators and co-generators. Electricity also competes with other forms of energy. Competition also arises from customers supplying their own power through distributed generation, which is the generation of electricity on-site or close to where it is needed in small facilities designed to meet local needs. Distributed energy resources can include combined heat and power, solar photovoltaic, wind, battery storage, thermal storage and demand-response technologies. The degree of competition may vary from time to time depending on relative costs and supplies of other forms of energy and advances in technology. Irrespective of the competitive environment, we are focused on providing value to our customers and ensuring our retail rates remain among the lowest in the region and in the nation. The following table presents our average retail rate per kilowatt-hour (kwh) by customer class and in total for the years ended December 31, 2022 and 2021: ##TABLE_START Revenue per kwh 2022 2021 Residential 10.99 10.90 Commercial Industrial 7.54 7.52 Total Retail 8.41 8.47 ##TABLE_ENDWholesale electricity markets are competitive under the Federal Energy Regulatory Commission (FERC) open access transmission tariffs, which require utilities to provide nondiscriminatory access to all wholesale users. In addition, the FERC has established a competitive process for the construction and operation of certain new electric transmission facilities whereby electric transmission providers, including the Midcontinent Independent System Operator, Inc. (MISO), of which OTP is a member, are required to remove from their tariffs a federal right of first refusal to construct transmission facilities selected in a regional transmission plan for purposes of cost allocation. The FERC is contemplating potential reforms for electric regional transmission planning, cost allocation and generator interconnection processes. While the ultimate regulatory outcome is uncertain at this time, changes to the regulatory framework could impact future transmission investments. Franchises OTP has franchises to operate as an electric utility in substantially all of the incorporated municipalities it serves. Franchise rights generally require periodic renewal. No franchises are required to serve unincorporated communities in any of the three states OTP serves. GENERATION AND PURCHASED POWER OTP primarily relies on company-owned generation, supplemented by power purchase agreements, to supply the energy to meet our customer needs. Wholesale market purchases and sales of electricity are used as necessary to balance supply and demand. Our mix of owned generation and wholesale market energy purchases to meet customer demand are impacted by wholesale energy prices and the relative cost of each energy source. As of December 31, 2022, OTPs wholly- or jointly-owned plants and facilities, as well as in place power purchase agreements, and their dependable kilowatt (kW) capacity were: ##TABLE_START Capacity / Purchased Power in kW Owned Generation: Baseload Plants Big Stone Plant (1) 258,000 Coyote Station (2) 148,200 Total Baseload Plants 406,200 Combustion Turbine and Small Diesel Units Astoria Station 242,200 All Other 101,500 Total Combustion Turbine and Small Diesel Units 343,700 Owned Wind Facilities (rated at nameplate) Merricourt Wind Energy Center 150,000 Luverne Wind Farm 49,500 Ashtabula Wind Center 48,000 Langdon Wind Center 40,500 Total Owned Wind Facilities 288,000 Hydroelectric Facilities 2,500 Total Owned Generation Capacity 1,040,400 Power Purchase Agreements: Purchased Wind Power (rated at nameplate and greater than 2,000 kW) Ashtabula Wind III (3) 62,400 Edgeley 21,000 Langdon 19,500 Total Purchased Wind 102,900 Total Generating Capacity 1,143,300 (1) Reflects OTP's 53.9% ownership percentage of jointly-owned facility. (2) Reflects OTP's 35.0% ownership percentage of jointly-owned facility. (3) OTP acquired the assets of the Ashtabula III wind farm on January 3, 2023. ##TABLE_ENDThe following charts summarize the percentage of our generating capacity by source, including owned and jointly-owned facilities and through power purchase arrangements, as of December 31, 2022 and 2021: Under MISO requirements, OTP is required to provide sufficient capacity through wholly- or jointly-owned generating capacity or power purchase agreements to meet its monthly weather-normalized forecast demand, plus a reserve obligation. On August 31, 2022, FERC issued an order to approve MISO's proposal to revise its resource adequacy requirement, including the adoption of a seasonal resource adequacy construct rather than a single requirement based on a summer peak. MISO proposed the seasonal adequacy construct to address significant increases in emergency declarations that occur throughout the year, driven by factors including declining excess reserve margin, generation retirements, reliance on intermittent resources and outages resulting from extreme weather events. These new provisions will be implemented in the 2023/2024 planning year. Under the new seasonal resource adequacy construct, the seasonal reserve margin requirements deviate significantly from MISOs 2022/2023 annual planning reserve margin requirements. For planning year 2022/2023, the last year under the annual construct, our required planning reserve margin was 8.7%. For planning year 2023/2024, under the new seasonal construct, our planning reserve margin requirements range between 7.4% and 25.5%, depending on the season. The following charts summarize the percentage of retail kwh sold by source during the years ended December 31, 2022 and 2021: Capacity Retirements and Additions Hoot Lake Plant , our 142-megawatt coal-fired power plant in Fergus Falls, Minnesota was retired in mid-2021. As part of our investment plan to meet our future energy needs, the following significant projects are at various stages of planning and construction or have been recently completed: Merricourt Wind Energy Center (Merricourt) is a 150-megawatt wind farm located in southeastern North Dakota. The facility was placed into commercial operation in December 2020, with a total cost of approximately $260 million. Astoria Station Natural Gas Plant (Astoria) is a 245-megawatt simple cycle natural gas combustion turbine generation facility near Astoria, South Dakota. The facility was placed into commercial operation in February 2021, with a total cost of approximately $160 million. Hoot Lake Solar is a 49-megawatt solar farm under construction on and around our Hoot Lake Plant property in Fergus Falls, Minnesota, with an anticipated cost of approximately $60 million. We anticipate the facility will be in commercial operation by the end of 2023. Ashtabula III Wind Farm is a 62-megawatt wind farm located in eastern North Dakota. The facility was purchased for approximately $50 million in January 2023. Prior to the purchase of the wind farm assets, we were purchasing the wind-generated electricity from the wind farm pursuant to a power purchase agreement. ENERGY TRANSITION OTP is committed to transitioning to a lower-carbon and increasingly clean energy future, while maintaining affordable and reliable electricity to serve our customers. We have developed the following goals in furtherance of our efforts to support the energy transition: Own or purchase energy generation thats more than 50% renewable by 2025 . Reduce carbon emissions from owned generation resources 50% by 2025 from 2005 levels. Reduce carbon emissions from owned generation resources 97% by 2050 from 2005 levels. To date, we have undertaken numerous initiatives to reduce our carbon footprint and mitigate greenhouse gas (GHG) emissions in the process of generating electricity for our customers. Our initiatives include increasing the efficiency of our plants, retiring Hoot Lake Plant, adding renewable energy to our resource mix and sponsoring energy conservation programs. From 2005 through 2022, we have reduced our carbon dioxide (CO_2) emissions approximately 43% and increased the amount of renewable generation resources we own or purchase through power purchase agreements by approximately 370-megawatts. Our future resource plans to deliver affordable, reliable, and increasingly clean energy to our customers include the addition of 49-megawatts of solar energy from Hoot Lake Solar in 2023 and repowering various wind farm assets to increase their efficiency and output. The following chart depicts our energy resource mix, which is the electricity we use to serve our customers, in 2005 and 2022 and the projected mix in 2030 and 2050. The amounts include energy generated from owned resources, procured through power purchase agreements and energy purchased in the wholesale market: Inflation Reduction Act On August 16, 2022, the Inflation Reduction Act of 2022 (IRA) was signed into law. The IRA includes funding for climate and clean energy investments and other provisions affecting corporate taxpayers. The climate and clean energy provisions of the IRA include, among other items, i) the extension of the traditional production tax credits (PTC) and investment tax credits (ITC) for renewable technologies (including wind and solar) if construction is begun before 2025, along with elimination of the existing phase-down of the PTC and ITC, and transitions to a new technology neutral credit for property placed in service after 2024, ii) a new PTC for sale of domestically produced electricity with a GHG emission rate of not greater than zero produced at a qualifying facility placed in service after 2024, iii) a new ITC for investment in qualifying zero-emission electricity generation facilities or energy storage technology placed in service after 2024, and iv) alternative ways to monetize renewable tax credits by allowing certain entities to sell tax credits to third parties. The tax incentives provided under the IRA are intended to incentivize the transition to a cleaner energy economy and to reduce GHG emissions from the electric utility industry. These financial incentives could impact the planning of our future generation resources and our long-term capital spending plan. See the Integrated Resource Plan (IRP) section below for additional details on how the passage of the IRA has impacted our recently filed IRP. RESOURCE MATERIALS Coal is the principal fuel burned at our jointly-owned Big Stone and Coyote Station generating plants. Coyote Station, a mine-mouth facility, burns North Dakota lignite coal. Big Stone Plant burns western subbituminous coal transported by rail. We source coal for our coal-fired power plants through requirements contracts which do not include minimum purchase requirements but do require all coal necessary for the operation of the respective plant to be purchased from the counterparty. Our coal supply contracts for our Big Stone Plant and Coyote Station have expiration dates in 2024 and 2040. The supply agreement between the Coyote Station owners, including OTP, and the coal supplier includes provisions requiring the Coyote Station owners to purchase the membership interests and pay off or assume loan and lease obligations of the coal supplier, as well as complete mine closing and post-mining reclamation, in the event of certain early termination events and at the expiration of the coal supply agreement in 2040. See below and Note 1 to our consolidated financial statements included in this report on Form 10-K for additional information. Coal is transported to our non-mine-mouth facility, Big Stone Plant, by rail and is provided under a common carrier rate which includes a mileage-based fuel surcharge. We purchase natural gas for use at our combustion turbine facilities based on anticipated short-term resource needs. We procure natural gas from multiple vendors at spot prices in a liquid market primarily under firm delivery contracts. TRANSMISSION AND DISTRIBUTION Our transmission and distribution assets deliver energy from energy generation sources to our customers. In addition, we earn revenue from the transmission of electricity over our wholly- or jointly-owned transmission assets for others under approved rate tariffs. As of December 31, 2022, we were the sole or joint owner of nearly 15,000 miles of transmission and distribution lines. Midcontinent Independent System Operator MISO is an independent, non-profit organization that operates the transmission facilities owned by other entities, including OTP, within its regional jurisdiction and administers energy and generation capacity markets. MISO has operational control of our transmission facilities above 100 kilovolts (kV). MISO seeks to optimize the efficiency of the interconnected system, provide solutions to regional planning needs and minimize risk to reliability through its security coordination, long-term regional planning, market monitoring, scheduling and tariff administration functions. In 2022, MISO approved several projects within the first tranche of its long-range transmission plan, which includes two new 345 kV transmission projects and a project to upgrade an existing transmission line. OTP will have a varying level of ownership interest in these projects, which will be completed over several years, and our total capital investment in these projects is anticipated to be approximately $390 million. SEASONALITY Electricity demand is affected by seasonal weather differences, with peak demand occurring in the summer and winter months. As a result, our Electric segment operating results regularly fluctuate on a seasonal basis. In addition, fluctuations in electricity demand within the same season but between years can impact our operating results. We monitor the level of heating and cooling degree days in a period to assess the impact of weather-related effects on our operating results between periods. PUBLIC UTILITY REGULATION OTP is subject to regulation of rates and other matters in each of the three states in which it operates and by the federal government for, among other matters, the interstate transmission of electricity. OTP operates under approved retail electric tariff rates in all three states it serves. Tariff rates are designed to recover plant investments, a return on those investments, and operating costs. In addition to determining rate tariffs, state regulatory commissions also authorize return on equity (ROE), capital structure, and depreciation rates of our plant investments. Decisions by our regulators significantly impact our operating results, financial position, and cash flows. Below is a summary of the regulatory agencies with jurisdiction of electric rates over OTP covered by each regulatory agency: ##TABLE_START Regulatory Agency Areas of Regulation Minnesota Public Utilities Commission (MPUC) Retail rates, issuance of securities, depreciation rates, capital structure, public utility services, construction of major facilities, establishment of exclusive assigned service areas, contracts with subsidiaries and other affiliated interests and other matters. Selection or designation of sites for new generating plants (50,000 kW or more) and routes for transmission lines (100 kV or more). Review and approval of fifteen-year Integrated Resource Plan. North Dakota Public Service Commission (NDPSC) Retail rates, certain issuances of securities, construction of major utility facilities and other matters. Approval of site and routes for new electric generating facilities (500 kW for wind generating facilities; 50,000 kW for non-wind generating facilities) and high voltage transmission lines (115 kV). Review and approval of fifteen-year Integrated Resource Plan. South Dakota Public Utilities Commission (SDPUC) Retail rates, public utility services, construction of major facilities, establishment of assigned service areas and other matters. Approval of sites and routes for new electric generating facilities (100,000 kW or more) and most transmission lines (115 kV or more). Federal Energy Regulatory Commission (FERC) Wholesale electricity sales, transmission and sale of electric energy in interstate commerce, interconnection of facilities, hydroelectric licensing and accounting policies and practices. Compliance with North American Electric Reliability Corporation (NERC) reliability standards, including standards on cybersecurity and protection of critical infrastructure. ##TABLE_ENDIn addition to base rates, which are established through periodic rate case proceedings within each state jurisdiction, there are other mechanisms for recovery of plant investments, including a return on investment and operating expenses, between rate cases. The following table summarizes these recovery mechanisms: ##TABLE_START Recovery Mechanism Jurisdiction(s) Additional Information Fuel Clause Adjustment (FCA) MN, ND, SD Provides for periodic billing adjustments for changes in prudently incurred costs of fuel and purchased power. In North and South Dakota, fuel and purchased power costs are generally adjusted on a monthly basis with over or under collections from the previous month applied to the next monthly billing. In Minnesota, fuel and purchased power costs are estimated on an annual basis and the accumulated difference between actual and estimated cost per kwh are refunded or recovered, subject to regulatory approval, in subsequent periods. Transmission Cost Recovery Rider (TCR) MN, ND, SD Provides for the recovery of costs outside of a general rate case for investments in new or modified electric transmission assets and certain MISO transmission service and related costs. Environmental Cost Recovery Rider (ECR) MN, ND, SD Provides for the recovery of costs outside of a general rate case for investments in certain environmental improvement projects. Renewable Resource Rider (RRR) MN, ND Provides for the recovery of costs outside of a general rate case for investments in certain new renewable energy projects. Conservation Improvement Program (CIP) MN Under Minnesota law, OTP is required to save 1.75% of its gross retail energy revenues through the energy conservation and optimization program. Recovery of these costs outside of a general rate case occurs through the CIP rider. Electric Utility Infrastructure Costs Rider (EUIC) MN Provides for the recovery of costs for investments made to replace or modify existing infrastructure if the replacement or modification conserves energy or uses energy more efficiently. Advanced Meter and Distribution Technology Cost Recovery Rider (AMDT) ND Provides for the recovery of costs for advanced metering infrastructure, outage management systems and demand response projects. Generation Cost Recovery Rider (GCR) ND Provides for the recovery of costs outside of a general rate case for investments in new generation facilities. Energy Efficiency Plan (EEP) SD Provides for the recovery of costs from energy efficiency investments. Phase-In Rider (PIR) SD Provides for the recovery of costs outside of a general rate case for investments in new generation facilities and advanced grid infrastructure. ##TABLE_ENDIntegrated Resource Plan Under Minnesota law, utilities are required to submit for approval by the MPUC a 15-year advance IRP. An IRP is a set of resource options a utility could use to meet the service needs of its customers over the forecast period, including an explanation of the utilitys supply and demand circumstances, and the extent to which each resource option would be used to meet those service needs. The MPUCs findings of fact and conclusions regarding IRPs are considered to be prima facie evidence, subject to rebuttal, in future rate reviews and other proceedings. Typically, IRPs are submitted every two years. In 2021, the North Dakota Legislative Assembly enacted a provision requiring investor-owned electric utilities to submit an IRP to the NDPSC and granted the NDPSC the authority to adopt rules and regulations for the preparation and submission of IRPs. The NDPSC's rules and regulations were finalized and became effective on January 1, 2023. Under the finalized regulation, utilities are required to submit, for approval by the NDPSC, a 15-year advance IRP every three years. On September 1, 2021, OTP filed its 2022 IRP concurrently with regulators in Minnesota, North Dakota and South Dakota. The 2022 IRP included OTPs preferred plan for meeting customers anticipated capacity and energy needs while maintaining system reliability and affordable electric service rates, based on the information available at that time. The preferred plan as outlined in the 2022 IRP included the addition of dual fuel capabilities at our Astoria natural gas plant, the addition of 150-megawatts of solar generation, the addition of 100-megawatts of wind generation, and the commencement of the process of withdrawing from our 35 percent ownership interest in Coyote Station, a jointly-owned, coal-fired generation plant, by December 31, 2028. Subject to regulatory approval, the preferred plan proposed to create a regulatory asset as a vehicle to recover costs related to a future withdrawal from Coyote Station, including the net book value of the plant on the withdrawal date, anticipated decommissioning costs and any required costs incurred as a result of an early termination of the existing lignite sales agreement (LSA), under which Coyote Station acquires all of its lignite coal from a nearby mine. As part of the filing, OTP developed an estimate of the reasonably foreseeable costs of withdrawing from Coyote Station at the end of 2028 of $68.5 million. These costs may differ from actual results due to the uncertainty and timing of future events associated with the terms and conditions of a withdrawal. On October 14, 2022, OTP submitted a supplemental filing to update its 2022 IRP, requesting the procedural schedule in Minnesota be amended to allow additional time to update our resource modeling given significant changes in the energy industry since the original 2022 IRP filing, while maintaining the original procedural schedule as it relates to adding dual fuel capability at Astoria. Our original filing proposed fuel oil as the secondary on-site fuel at Astoria and our supplemental filing reflects revised cost estimates and proposes liquified natural gas as the most cost-effective secondary fuel source. The primary changes and events which led to OTP's request include FERCs approval of MISOs new seasonal resource adequacy construct, MISOs proposal to significantly increase winter and spring planning reserve margins, and enactment of the IRA. A notice of the request submitted to the MPUC was also provided to the NDPSC and SDPUC. On November 1, 2022, the MPUC approved OTP's requested changes to the procedural schedule for the 2022 IRP. OTP plans to file an updated resource plan in March 2023, pursuant to the amended schedule. In conjunction with the updated resource plan, OTP's preferred plan could change based on the results of updated resource modeling incorporating the factors listed above, as well as other changes. A change to the preferred plan could ultimately impact the nature, timing and amount of future capital investments, as well as the potential for OTP's withdrawal from Coyote Station. Capital Structure Petition Minnesota law requires an annual filing of a capital structure petition with the MPUC. In this filing the MPUC reviews and approves OTP's capital structure. Once approved, OTP may issue securities without further petition or approval, provided the issuance is consistent with the purposes and amounts set forth in the approved petition. OTPs current capital structure approved by the MPUC on November 8, 2022, allows for an equity-to-total-capitalization ratio between 47.5% and 58.0%, with total capitalization not to exceed $1.8 billion. Renewable Energy Standard Minnesota has a renewable energy standard requiring utilities to generate or procure sufficient renewable generation such that the following percentages of total retail electric sales to Minnesota customers come from qualifying renewable sources: 25% by 2025 and 55% by 2035. Qualifying renewable sources are classified as wind, hydropower, hydrogen, and certain biomass generation. We met the current renewable sources requirements with a combination of owned renewable generation and purchases from renewable generation sources. Minnesota law also requires 1.5% of total Minnesota retail electric sales by public utilities to be supplied by solar energy. For a public utility with between 50,000 and 200,000 retail electric customers, such as OTP, at least 10% of the 1.5% requirement must be met by solar energy generated by or procured from solar photovoltaic devices with a nameplate capacity of 40 kW or less. OTP plans to purchase Solar Renewable

Energy Credits to meet its obligations until its Hoot Lake Solar and other solar projects are complete and operational. Under certain circumstances, and after consideration of customers' utility costs and reliability issues, the MPUC may modify or delay implementation of the standards. We are evaluating potential options for maintaining compliance and meeting the solar energy standard beyond 2022. Minnesota Clean Energy Bill In February 2022, Minnesota enacted the Clean Energy Bill, which requires electric utilities to generate or procure sufficient electricity from carbon-free resources, to provide retail customers in Minnesota with at least the following percentages of carbon-free electric energy: 80% by 2030, 90% by 2035, and 100% by 2040. Carbon-free resources include wind, solar, hydropower, and nuclear generation. To provide flexibility, the law allows electric utilities to use renewable energy credits (RECs) to offset carbon emissions and for the MPUC to consider whether a regulated utility's requirement to meet established standards should be delayed due to affordability or reliability impacts. OTP is in the process of reviewing its plan for compliance with the newly enacted law. ENVIRONMENTAL REGULATION OTP is subject to stringent federal and state environmental standards and regulations regarding, among other things, air, water and solid waste pollution. OTP's facilities have been designed, constructed and, as necessary, updated to operate in compliance with applicable environmental regulations. However, new or amended laws and regulations or changes in interpretations of current laws and regulations may require additional pollution control equipment or emission reduction measures and there can be no assurance that our facilities will remain economic to operate. Prudent expenditures incurred to comply with environmental regulations are eligible to be recovered in rates authorized by regulators in jurisdictions in which we operate; however, there can be no assurance that future costs will be authorized for recovery. Alternatively, additional pollution control equipment or other emission reduction measures may prove to be uneconomic potentially leading to the exiting of a facility earlier than originally planned. As it relates to our jointly-owned facilities, we may determine it is necessary to transfer, sell or otherwise divest of our ownership, or the ownership group may determine the early closure or repurposing of a facility is necessary. For the five-year period ended December 31, 2022, OTP invested approximately $10.4 million in environmental control facilities, including $0.4 million in 2022. Our construction budget for the next five years includes approximately $6.1 million of capital investments in environmental control equipment. The timing and amount of our expenditures may change as the regulatory environment changes. Among current regulatory requirements, the federal Regional Haze Rule (RHR) could have the most significant impact on our operating results, financial condition and liquidity. The Environmental Protection Agency (EPA) adopted the RHR in 1999 as an effort to improve visibility in national parks and wilderness areas. The RHR requires states, in coordination with the EPA and other governmental agencies, to develop and implement state implementation plans (SIPs) which work towards achieving natural visibility conditions by the year 2064, to set goals to ensure reasonable progress is being made, and to periodically evaluate whether those goals and progress are on track or whether additional emission reductions are appropriate. The second RHR implementation period covers the years 2018-2028. States are required to submit a state implementation plan to assess reasonable progress with the RHR and determine what additional emission reductions are appropriate, if any. Coyote Station is subject to assessment in the second implementation period under the North Dakota SIP for the RHR. The North Dakota Department of Environmental Quality (NDDEQ) submitted its proposed SIP to the EPA for approval in August 2022. In its plan, the NDDEQ concluded it is not reasonable to require additional emission controls during this planning period. The EPA submitted comments during the development of the SIP requesting NDDEQ to reassess its determination for Coyote Station. The EPA is anticipated to take proposed action and potential final action on the SIP in 2023. See Note 13 to our consolidated financial statements for additional information. Climate Change and Greenhouse Gas Regulation Global climate change presents a significant energy and environmental policy challenge. Combustion of fossil fuels for the generation of electricity is a considerable source of CO_2 emissions, which is the primary GHG emitted by our utility operations. The federal government and many states are pursuing climate policies to regulate GHG emissions as part of a broad-based effort to limit global warming. In February 2021, the U.S. rejoined the United Nations Framework Convention on Climate Change (the Paris Agreement), which is a legally binding international treaty on climate change adopted by over 190 countries. The goal of the Paris Agreement is to limit the global temperature increase to well below 2 Celsius compared to pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5 Celsius. The Biden Administration has announced the goal of reducing GHG emissions by 50 to 52 percent from 2005 levels in 2030 and to reach 100 percent carbon pollution-free electricity by 2035 as part of the U.S. plan to achieve the goals under the Paris Agreement. In February 2022, Minnesota enacted the Clean Energy Bill, which requires electric utilities to generate or procure sufficient electricity from carbon-free resources to provide retail customers in Minnesota with at least the following percentages of carbon-free electric energy: 80% by 2030, 90% by 2035, and 100% by 2040. The implementation of climate change programs, such as the Paris Agreement, the Minnesota Clean Energy Bill, and other federal or state regulations targeting GHG emissions may have a significant impact on our utility business. Specific regulatory measures to address climate change continue to evolve. In January 2021, the EPA's Affordable Clean Energy Rule (ACE Rule), which required states to develop plans for GHG emissions from coal-fired power plants, was vacated by the U.S. Court of Appeals for the District of Columbia Circuit. In October 2021, the U.S. Supreme Court agreed to hear a consolidated challenge to the Court of Appeals decisions. In June 2022, the U.S. Supreme Court issued its opinion in the case of West Virginia v. EPA, finding that in Section 111(d) of the Clean Air Act, Congress did not grant the EPA the authority to broadly regulate GHG emissions under the Clean Air Act, including the setting of emissions limits for existing power plants based on the power sectors ability to shift to cleaner renewable energy sources (a process known as generation shifting).

The Supreme Court found that the authority to regulate issues that have broad economic or political consequences (known as the major questions doctrine) requires explicit Congressional authorization in law. In the first half of 2023, the EPA is expected to issue a proposed rule under Clean Air Act section 111(d), replacing or revising the previously proposed ACE rule. Although this future proposed rule is subject to the constraints of the Supreme Courts West Virginia v. EPA decision, the rule nevertheless has the potential to impact the emissions controls needed at OTPs coal-fired power plants. While the future financial impact of any current, proposed, or pending litigation or regulation of GHG or other emissions is unknown at this time, any capital or operating costs incurred for additional pollution control equipment or emission reduction measures could materially adversely impact our future operating results, financial position, and liquidity unless such costs could be recovered through related rates and/or future market prices for energy. ##TABLE_START MANUFACTURING Contribution to Operating Revenues: 27% (2022), 28% (2021), 27% (2020) ##TABLE_ENDManufacturing consists of businesses engaged in the following activities: contract machining, metal parts stamping, fabrication and painting, and production of plastic thermoformed horticultural containers, life science and industrial packaging, and material handling components and extruded raw material stock. The following is a brief description of each of these businesses: BTD Manufacturing, Inc. (BTD), with headquarters located in Detroit Lakes, Minnesota, provides metal fabrication services for custom machine parts and metal components through metal stamping, tool and die, machining, tube bending, welding and assembly in its facilities in Detroit Lakes and Lakeville, Minnesota, Washington, Illinois and Dawsonville, Georgia. T.O. Plastics, Inc. (T.O. Plastics) , with facilities in Otsego and Clearwater, Minnesota, manufactures extruded and thermoformed plastic products, including custom parts for customers in several industries and its own line of horticulture containers. Examples of products produced include clamshell packing, blister packs, returnable pallets and handling trays for shipping and storing odd-shaped or difficult-to-handle parts. CUSTOMERS Our metal fabrication business primarily serves Midwestern and Southeastern U.S. manufacturers in the recreational vehicle, lawn and garden, agricultural, construction, and industrial and energy equipment end markets. Our plastic products business serves primarily U.S. customers in the horticulture, medical and life sciences, industrial, recreational and electronics industries. The principal method of production distribution is by direct shipment to our customers through direct customer pick-up or common carrier ground transportation. No single customer or product of our Manufacturing segment businesses accounted for 10% or more of our consolidated operating revenues in 2022. However, the top three customers combined to account for 50% and 46% of our 2022 and 2021 Manufacturing segment operating revenues, respectively. COMPETITIVE CONDITIONS The various markets in which we compete are characterized by intense competition from both foreign and domestic manufacturers. These markets have many established manufacturers with broader product lines, greater distribution capabilities, greater capital resources, excess capacity, labor advantages and larger marketing, research and development staffs and facilities than our own. We believe the principal competitive factors in our Manufacturing segment are product performance, quality, price, technical innovation, cost effectiveness, customer service and breadth of product line. We intend to continue to compete based on high-performance products, innovative production technologies, cost-effective manufacturing techniques, close customer relations and support, and increasing product offerings. RESOURCE MATERIALS We use raw materials in the products we manufacture, including, among others, steel, aluminum, and polystyrene and other plastics resins. Managing price volatility and ensuring raw material availability are important aspects of our business. We attempt to pass increases in the costs of these raw materials through to our customers. Increases in the costs of raw materials that cannot be passed on to customers could have a negative effect on profit margins. Additionally, a certain amount of residual material (scrap) is a by-product of the manufacturing and production processes. Declines in commodity prices for these scrap materials due to weakened demand or excess supply can negatively impact the profitability of our Manufacturing segment as it reduces their ability to mitigate the costs associated with excess material. ENVIRONMENTAL REGULATION Our manufacturing businesses are subject to environmental, health and safety laws and regulations, including those governing discharges to air and water, the management and disposal of hazardous substances, the cleanup of contaminated sites and health and safety matters. ##TABLE_START PLASTICS Contribution to Operating Revenues: 35% (2022), 32% (2021), 23% (2020) ##TABLE_ENDPlastics consists of businesses producing PVC pipe at plants in North Dakota and Arizona. The following is a brief description of these businesses: Northern Pipe Products, Inc. (Northern Pipe) , located in Fargo, North Dakota, manufactures and sells PVC pipe for municipal water, rural water, wastewater, storm drainage systems and other uses in the northern, midwestern, south-central and western regions of the United States as well as central and western Canada. Vinyltech Corporation (Vinyltech) , located in Phoenix, Arizona, manufactures and sells PVC pipe for municipal water, wastewater, water reclamation systems and other uses in the western, northwest and south-central regions of the United States. PVC pipe is manufactured through a process known as extrusion. During this process, PVC compound (a dry powder-like substance) is introduced into an extrusion machine, where it is heated to a molten state and then forced through a sizing apparatus to produce the pipe. The newly extruded pipe is pulled through a series of water-cooling tanks, marked to identify the type of pipe and cut to finished lengths. CUSTOMERS PVC pipe products are marketed through a combination of independent sales representatives, company salespersons and customer service representatives. Customers for our PVC pipe products consist primarily of wholesalers and distributors and the principal method for distribution of our products is by common carrier ground transportation. No single customer of the PVC pipe companies accounted for 10% or more of our consolidated operating revenues in 2022. However, two customers, both of which are distributors of PVC pipe, combined to account for 46% and 50% of our 2022 and 2021 Plastics segment operating revenues, respectively. COMPETITIVE CONDITIONS The plastic pipe industry is fragmented and competitive due to the number of producers, the small number of raw material suppliers and the fungible nature of the product. Due to shipping costs, competition is usually regional instead of national in scope. The principal factors of competition are price, customer service and product performance. We compete not only against other plastic pipe manufacturers, but also ductile iron, high-density polyethylene, steel and concrete pipe producers. Pricing pressure will continue to affect our operating margins in the future. We will continue to compete based on our high-quality products, cost-effective production techniques and close customer relations and support. RESOURCE MATERIALS PVC resins are acquired in bulk and shipped to our facilities by rail. There are four vendors from which we can source our PVC resin requirements. In 2022 we sourced all of our PVC resin from two vendors. Our contractual arrangements to acquire resin generally include estimated annual order quantities with no required minimum purchases, and include variable pricing based on market prices for resin. The supply of PVC resin may also be limited primarily due to manufacturing capacity and the limited availability of raw material components. Most U.S. resin production plants are located in the Gulf Coast region. These plants are subject to the risk of damage and production shutdowns because of exposure to hurricanes or other extreme weather events that occur in this part of the United States. The loss of a key vendor, or any interruption or delay in the supply of PVC resin could disrupt the ability of our Plastics segment businesses to manufacture products, cause customers to cancel orders or result in increased expenses for obtaining PVC resin from alternative sources, if such sources were available. We believe we have good relationships with our key raw material vendors. Due to the commodity nature of PVC resin and PVC pipe and the dynamic supply and demand factors worldwide, historically the markets for both PVC resin and PVC pipe have been very cyclical with significant fluctuations in prices and gross margins. In addition to PVC resin, we use certain other materials, such as stabilizers, gaskets and lumber, in the process of manufacturing and shipping our PVC pipe products. We generally source these materials from a limited number of suppliers, and supply chain constraints or disruptions related to these materials could disrupt our ability to manufacture or ship products and could result in increased costs. SEASONALITY Demand for our PVC pipe products can be impacted by seasonal weather differences, with generally lower sales volumes realized in the first quarter of the year when cold temperatures and frozen ground across the northern portion of our footprint can delay or prevent construction activity and consequently delay or prevent customer orders of PVC pipe. ENVIRONMENTAL REGULATION Our plastics businesses are subject to environmental, health and safety laws and regulations, including those governing discharges to air and water, the management and disposal of hazardous substances, the cleanup of contaminated sites and health and safety matters. ##TABLE_START ITEM 1A. RISK FACTORS ##TABLE_ENDRISK FACTORS AND CAUTIONARY STATEMENTS Our businesses are subject to various risks and uncertainties. Any of the risks described below or elsewhere in this report on Form 10-K or in our other SEC filings could materially adversely affect our business, operating results, financial condition and liquidity. Additional risks and uncertainties we are not presently aware of or that we currently consider immaterial may also affect our business, operating results, financial condition and liquidity. Oversight of Risk and Related Processes A key accountability of the Board of Directors is the oversight of material risk. Management and the Board of Directors have responsibility for overseeing the identification and mitigation of significant and emerging risks. Management identifies and analyzes risks to determine the impact and other attributes such as timing, likelihood and management control. Identification and analysis occur formally through an assessment of significant and emerging risks conducted by senior management, the financial disclosure process, and internal auditing and compliance with financial and operational controls. Management also identifies and analyzes risk through the development of goals and key performance indicators, which include risk identification to determine barriers to implementing our strategy. We promote a culture of compliance, including tone at the top. The process for risk mitigation includes adherence to our code of business ethics and compliance policies, operation of formal risk management structures and overall business management to mitigate the risks inherent in the implementation of strategy. We manage and further mitigate risks through formal risk management structures, including a management executive risk committee and internal business functions such as internal audit/business risk management and legal. Management communicates regularly with our Board of Directors and key stakeholders regarding risk. Senior management presents and communicates a periodic risk assessment to our Board of Directors which provides information on the risks management believes are material, including the earnings impact, timing, likelihood and management control. The Board of Directors approaches oversight, management and mitigation of risk as an integral and continuous part of its governance of Otter Tail Corporation. The Board of Directors regularly reviews managements top risk assessment and analyzes areas of existing and future risks and opportunities. Finally, the Board of Directors conducts an annual strategy session where our future plans and initiatives are reviewed. OPERATIONAL RISKS Our strategy includes large capital investments, which are subject to risks. Our business strategy includes major capital investments at our existing companies. Our capital investment program planned for the next five years includes Electric segment investments in renewable generation, transmission asset additions and upgrades, and technology and infrastructure projects, and Manufacturing and Plastics segments investments in facilities, equipment and machinery. These capital projects are planned years in advance of their in-service dates and are subject to various risks including: obtaining necessary permits, licenses and timely approvals; adverse changes in regulatory treatment or public policy; changes in commodity pricing, equipment and construction costs; technology changes; delivery delays of critical materials and components; delays caused by construction accidents, injuries or public health crises; adverse weather conditions; unforeseen product defects; limited access to capital; and other adverse conditions. Capital investments in our Electric segment require regulatory approval and are subject to the risks of not being granted timely or allowed to be fully recovered. The inability to complete capital projects on budget and in a timely manner could adversely impact our operating results and financial condition. Our acquisition or divestiture strategies are subject to risk and could adversely impact our financial position and operating results. As part of our business strategy, we continually assess our mix of businesses and potential strategic acquisitions or divestitures. This investment strategy is subject to various risks including the ability to identify appropriate acquisition candidates or successfully negotiate and finance any acquisitions. In addition, difficulties in integrating the operations, services, products and personnel of the acquired business, and the potential loss of key employees, customers and suppliers of the acquired business could adversely impact our financial condition and operating results. The sale of any of our businesses may result in the recognition of a loss if the business is sold for less than its book value and may expose us to risk arising from indemnification obligations that arose out of the conduct of the business prior to the sale. These obligations may include warranty and environmental obligations or the recoverability of certain assets sold as part of the transaction. Unforeseen costs related to these obligations could impact our operating results. Weather impacts, including normal seasonal fluctuation and extreme weather events, could adversely affect our operating results. Our Electric segment business is seasonal and weather patterns can have a material impact on our financial performance. Demand for electricity is normally greater in the winter and summer months. Unusually mild summers and winters could have an adverse effect on our financial condition and results of operations. Weather can also have a significant impact on our Plastics segment businesses as most U.S. PVC resin production plants are located in the Gulf Coast region, which is prone to seasonal hurricane activity and other extreme weather events. Our access to PVC resin may be impacted by the volume and magnitude of hurricane and storm activity in this region. In addition, our Plastics segment businesses can be affected by weather prohibiting or delaying construction projects at any time of the year in any geography, but specifically times of the year when frozen ground and cold temperatures in many parts of the country can delay construction projects, all of which can result in reduced customer demand. Our businesses are located in areas that could be subject to natural disasters such as severe snow and ice storms, tornadoes, flooding and fires. These factors could result in interruption of our business and damage to our facilities. An extreme weather event within our utility service area could directly affect our capital assets, causing disruption in service to customers and result in repair or replacement costs, due to downed wires and poles or damage to other operating equipment. In addition to variations in seasonal weather patterns, more widespread climate change may also create physical and financial risk to our businesses. Physical risks of climate change, such as more frequent or more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability and other phenomena, could affect some or all of our operations. Severe weather or other natural disasters related to climate change could be destructive and result in increased costs and disruptions in our operations. Extreme weather conditions, such as uncommonly long periods of high or low ambient temperature, generally require more utility system backup, adding to costs and contributing to increased system stress on our utility infrastructure, which could cause service interruptions. The loss of, or significant reduction in revenue from, any of our key customers could have an adverse effect on our operating results. While no single customer provided more than 10% of our consolidated operating revenues, each of our segments have customers which accounted for over 10% of the segments operating revenues. In 2022, one customer accounted for 11% of Electric segment revenues, three customers combined to account for 50% of Manufacturing segment operating revenues and two customers combined to account for 46% of Plastics segment operating revenues. The loss of any one of these customers or a significant decline in sales to these customers, would have a significant negative impact on the segment's financial condition and operating results, and could have a significant negative impact on the Companys consolidated financial condition, operating results and liquidity. Electric segment operating revenues also include sales to a customer that is a developer and operator of data centers which serve the high performance computing industry, with a concentration of customers involved in cryptocurrency mining and related activities. Customer demand from their cryptocurrency mining customers can directly impact our customer's demand for electricity. The cryptocurrency industry is highly volatile, and a significant decrease in cryptocurrency mining demand could have a negative impact on our customer's demand for electricity, and therefore negatively impact our operating revenues. We are subject to counterparty credit risk. We extend credit to our customers in the ordinary course of business in each of our operating segments. Our customers' ability to pay depends on a variety of factors including macroeconomic conditions, local economic conditions including unemployment rates, and industry conditions in which our customers operate. Increased customer delinquencies and bad debts could adversely impact our operating results and liquidity. Our operations are subject to environmental, health and safety laws and regulations. We are subject to numerous federal, state, and local environmental, health and safety laws and regulations governing, among other things, discharges to air and water, natural resources, hazardous waste and toxic substances, the cleanup of contaminated sites, and health and safety matters. Our failure to comply with applicable laws and regulations could result in civil or criminal fines or penalties, enforcement actions, and regulatory or judicial orders enjoining or curtailing operations or requiring corrective measures, which could materially and adversely affect our business. Compliance with these laws and regulations is a significant factor in our business. We have incurred and expect to continue to incur capital expenditures and operating costs to comply with applicable current and future laws and regulations. Our businesses continue to be subject to additional and changing environmental, health and safety laws and regulations, and we could incur additional costs complying with requirements that are promulgated in the future. Recently, various federal and state agencies have heightened their scrutiny of per- and polyfluoroalkyl substances (PFAS), which are manufactured chemicals used in a variety of consumer and industrial products. In August 2022, the U.S. EPA proposed to designate perfluorooctanesulfonic acid (PFOS) and perfluorooctanoic acid (PFOA), two of the most common PFAS chemicals, as hazardous substances, which could have wide-ranging impacts on companies across various industries, including ours. We are investigating whether PFAS compounds are used in our manufacturing or operating processes that occur in our various businesses. At this time, we cannot predict the outcome or the severity of the impact, if any, of future laws or regulations enacted to address PFAS. A cyber incident, security breach or system failure could adversely affect our business and operating results. The operation of our business is dependent on the secure functioning of our computer hardware and software systems. Furthermore, all our businesses require us to collect and maintain sensitive customer data, as well as confidential employee and shareholder information, which is subject to electronic theft or loss. We also use third-party vendors to electronically process certain of our business transactions. Information systems, both ours and those of third parties, are vulnerable to security breaches by computer hackers and cyber terrorists and the negligent or intentional breach of established controls and procedures or mismanagement of confidential information by employees. We may also be impacted by attacks and data security breaches of financial institutions, merchants or third-party service providers. While we employ a defense-in-depth strategy and regularly conduct cybersecurity assessments, we cannot be certain our information security systems and protocols and those of our vendors and other third parties are sufficient to withstand a cyber-attack or other security breach. A major cyber incident could result in significant expenses to investigate and repair security breaches or system damage and could lead to litigation, fines, other remedial action, heightened regulatory scrutiny and damage to our reputation. For example, we may be subject to liability under various federal, state and international data protection laws. These laws are subject to change and expansion and may require additional operational changes and costs to comply. The misappropriation, corruption or loss of personally identifiable information and other confidential data could lead to significant monetary damages, regulatory enforcement actions and breach notification and mitigation expenses, such as credit monitoring, and result in reputational damage affecting relations with shareholders, customers, regulators and others. In addition to property and casualty insurance, which may cover restoration of data, certain physical damage or third-party injuries, we have cybersecurity insurance related to a breach event. However, damage and claims arising from such incidents may not be covered or may exceed the amount of any available insurance. The inability to attract and retain a qualified workforce could have an adverse effect on our operations. The success of our business is heavily dependent on the leadership of our executive officers and key employees for implementation of our strategy. In addition, all of our businesses rely on a qualified workforce, including technical employees who possess certain specialized knowledge and skills. The inability to attract and retain a skilled and stable workforce at necessary staffing levels, whether due to decreases in hiring rates, increases in employee retirements, increases in terminations, or any combination thereof, may negatively affect our ability to service our customers, manufacture products or successfully manage our business and achieve our objectives. In 2022, we faced labor challenges within our Manufacturing segment businesses including difficulty attracting and retaining employees. In response, we offered increased compensation and hiring and retention incentives, which led to increased costs in our business. Should these challenges persist or exacerbate, our financial results could be impacted. If we are unable to maintain our desired staffing levels our ability to meet customer demand and achieve our growth targets could be negatively impacted. FINANCIAL RISKS We are subject to capital market and interest rate risks. We rely on access to debt and equity capital markets as a source of liquidity to fund our investment initiatives, including rate base growth investments in our Electric segment and opportunities for investment, including acquisitions, in our Manufacturing and Plastics segments. Capital markets are impacted by global and domestic economic conditions, monetary policy, commodity prices, geopolitical events and other factors. If we are unable to access capital on acceptable terms and at reasonable costs, our ability to implement our business plans may be adversely affected. In addition, higher market interest rates on outstanding variable-rate, short-term indebtedness could also impact our operating results. In 2022, rising market interest rates caused the applicable rate of interest on our short-term indebtedness to increase significantly. However, the impact to our operating results was not significant due to our low level of outstanding borrowings on our short-term indebtedness. Our operating results could be impacted if we significantly increase our short-term borrowings or issue new long-term debt, and interest rates remain elevated or continue to increase. A decrease in our credit ratings could increase our borrowing costs and result in additional contractual costs. We rely on our investment grade credit ratings to provide acceptable costs for accessing the capital markets. A downgrade of our credit ratings could result in higher borrowing costs thereby negatively impacting our operating results and limiting our ability to access capital markets, which may negatively impact our ability to implement our business plans. In addition, OTP is a party to contracts that require the posting of collateral or settlement of applicable contracts if credit ratings fall below certain levels. Our pension and other postretirement benefit plans are subject to investment and interest rate risks. The financial obligations and related costs of our pension and other postretirement benefit plans are affected by numerous factors. Assumptions related to future costs, investment returns, actuarial estimates and interest rates have a significant effect on our funding obligations and the cost recognized related to these plans. If our pension plan assets do not achieve our estimated long-term rate of return or if our other estimates prove to be inaccurate, our operating results, financial condition and liquidity may be adversely impacted. In addition, our funding requirements could be impacted by changes to the Pension Protection Act. We rely on our subsidiaries to provide sufficient earnings and cash flows to allow us to meet our financial obligations and pay dividends to our shareholders. Otter Tail Corporation is a holding company with no significant operations of its own. The primary source of funds for payment of our financial obligations and dividends to our shareholders is from cash provided by our subsidiary companies. Our ability to meet our financial obligations and pay dividends on our common stock principally depends on the earnings, cash flows, capital requirements and general financial positions of our subsidiary companies. In addition, OTP is subject to federal and state regulations which may restrict its ability to pay dividends. Finally, we are also reliant on our subsidiary companies to maintain compliance with financial covenants under our various short- and long-term debt agreements. Our debt agreements include restrictions on the payment of cash dividends upon an event of default. Changes in tax laws could materially affect our financial condition and operating results. Our provision for income taxes and tax obligations are impacted by various tax laws and regulations, including the availability of various tax credits, IRS tax policies such as tax normalization and, at times, the ability to carryforward net operating losses and tax credits. Changes in tax laws, regulations and interpretations could have an adverse effect on our financial condition and operating results. Tax law changes that reduce or eliminate production or investment tax credits may impact the economics of constructing certain electric generation resources, which may impact our planned investments and could adversely affect our financial condition and operating results. A significant impairment of our goodwill would negatively impact our financial position and operating results. As of December 31, 2022, we had $37.6 million of goodwill recorded on our consolidated balance sheet related to businesses within our Manufacturing and Plastics segments. Goodwill is tested for impairment annually or whenever events or changes in circumstances indicate impairment may have occurred. The goodwill impairment test requires us to estimate the fair value of the businesses being tested. Estimating the fair value of a business unit requires significant judgments and estimates, including estimates of future operating results and cash flows, among others. These estimates can be affected by numerous factors, including changes in economic, industry or market conditions, changes in business operations, changes in competition or changes in technologies. Any changes in key assumptions or material differences between actual and forecasted financial performance could affect our fair value estimates and lead to a goodwill impairment charge that could adversely affect our financial condition and operating results, as well as impact compliance with financing agreement covenants. ELECTRIC SEGMENT RISKS General economic and industry conditions impact our business. Several factors, many of which are beyond our control, may contribute to reduced demand for energy from our customers or increase the cost of providing energy to our customers. These risks include economic growth or decline in our service areas, demographic changes in our customer base and changes in customer demand or load growth due to, among other items, proliferation of distributed generation, energy efficiency initiatives and technological advancements. In addition, customer demand could be impacted by increased competition in our service territories or the loss of a service territory or franchise. Other risks include increased transmission or interconnection costs, generation curtailment and changes in the manner in which wholesale power is purchased and sold. A decrease in revenues or an increase in expenses related to our electric operations could negatively impact our financial condition, operating results and liquidity. Our utility business is significantly impacted by government legislation and regulation. OTP is subject to federal and state legislation and comprehensive regulation by federal and state regulatory agencies, including the public utility commissions in each of the three states in which OTP operates, and by the FERC. State utility commissions regulate, among other matters, the establishment of assigned service areas, the siting and construction of major facilities, the capital structure of the utility business, and the allowed rates to charge customers for providing energy and utility service. Each state utility commission operates independent of one another; therefore, OTP is subject to and must adhere to the decisions of each independent state commission. The FERC regulates, among other matters, wholesale energy transactions, hydroelectric licensing, transmission and sale of electric energy in interstate commerce, and the interconnection of electric facilities. Our financial condition, operating results and liquidity are significantly impacted by, and dependent upon, our ability to recover the costs associated with providing utility service and earn a return on our utility capital investments. There is no assurance that each state utility commission will judge our utility costs to have been prudently incurred or that rates will produce full recovery of such costs. In addition, changes in the federal or state regulatory framework could impair our ability to recover utility costs historically collected from our customers. In addition, prolonged inflationary cost pressures would increase the cost of constructing our utility assets and operating our utility business. Rising fuel costs in 2022 have increased the cost of providing energy to our customers. In each instance, there can be no assurance that our state regulatory commissions will authorize recovery of these rising costs. In addition to the recovery of our utility costs, our profitability is impacted by our authorized ROE, which can be impacted by macroeconomic factors such as interest rates. There can be no assurance that each state utility commission or the FERC will authorize a rate of return which allows us to achieve our financial goals. An adverse decision by one or more regulatory authorities concerning the level or method of determining electric utility rates; the authorized returns on equity; the authority to self-fund transmission upgrades; recoverability of fuel, purchase power and other costs; the allocation of costs between jurisdictions, approval of depreciation rates; implementation of enforceable federal reliability standards or other regulatory matters; permitted business activities, such as ownership or operation of nonelectric businesses; or any prolonged delay in rendering a decision in a rate or other proceeding could adversely impact our financial condition, operating results and liquidity. Our generating facilities are subject to risks that could result in early closure or the sale of our ownership interest. Changes in operational or economic factors, environmental regulation or risks of litigation could result in the early closure of or the sale of our interest in a generating facility. In the event of an early closure, a significant asset impairment charge could be required and we would be obligated to pay for our share of the costs of closure of the generating facility including costs associated with decommissioning, remediation, reclamation and restoration of the property, and any costs of terminating contracts associated with the generating facility, such as coal supply arrangements. In the event of a sale of our interest in a generating facility, we may not be able to negotiate the sale on favorable terms, which could result in the recognition of a loss on the sale and other potential liabilities. There can be no assurance that we would be authorized by any of our state utility commissions to recover any costs or losses associated with the early closure of or sale of our interest in a generating facility. The loss of a major generating facility would require OTP to identify and obtain approval for other sources of generation for its customers, if available, and expose it to higher purchased power costs. In addition, OTP may not be able to obtain timely regulatory approval for new generation resources to replace closed or sold facilities. In September 2021, our IRP filed in the three jurisdictions in which we operate outlined our plan to withdraw from our 35 percent ownership interest in Coyote Station, a jointly-owned coal-fired generation plant, by December 31, 2028. If we proceed with the withdrawal under the updated IRP which we expect to file in March 2023, we will seek to recover all costs related to the future withdrawal from Coyote Station, however, there can be no assurance that we will be granted recovery of any such costs. A full or partial denial of recovery of the costs of withdrawal could significantly impact our operating results, financial condition and liquidity. Federal and state environmental regulation could require us to incur substantial capital expenditures, increased operating costs or make it no longer economically viable to operate some of our facilities. We are subject to federal, state and local environmental laws and regulations relating to air quality, water quality, waste management, natural resources and health safety. These laws and regulations regulate the modification and operation of existing facilities, the construction and operation of new facilities and the proper storage, handling, cleanup and disposal of hazardous waste and toxic substances. Compliance with these legal requirements may require us to commit significant resources and funds toward environmental monitoring, installation and operation of pollution control equipment, payment of emission fees and securing environmental permits. Obtaining environmental permits can entail significant expense and cause substantial construction delays. Failure to comply with environmental laws and regulations, even if caused by factors beyond our control, may result in civil or criminal liabilities, penalties and fines. Coyote Station, one of OTP's jointly-owned coal-fired power plants, is subject to assessment under the second implementation period of RHR as part of the state of North Dakota's state implementation plan, or SIP. We cannot predict with certainty the impact the SIP may have on our business until the plan has been approved or otherwise acted on by the EPA, including its potential implementation of an alternative federal implementation plan. However, significant emission control investments could be required. Alternatively, investments in emission control equipment may prove to be uneconomic and result in the early closure of or the sale of our interest in Coyote Station. Existing environmental laws or regulations may be revised and new laws or regulations may be adopted or become applicable to us. The multiple jurisdictions that govern our electric utility business may not agree as to the appropriate resource mix, which may lead to costs incurred to comply with one jurisdiction that are not recoverable across all jurisdictions served by the same assets. Revised or additional regulations which result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material effect on our financial condition, operating results and liquidity, making the operation of some of our facilities no longer economically viable. Legislation, regulation, litigation or other actions related to climate change and greenhouse gas emissions could materially impact us. Current and future federal, state, regional and international regulations to address global climate change and reduce GHG emissions, including measures such as mandated levels of renewable generation, mandatory reductions in CO_2 emission levels, taxes on CO_2 emissions, or cap-and-trade regimes, could require us to incur significant costs which could negatively impact our financial condition, operating results and liquidity if such costs cannot be recovered through rates granted by rate-making authorities or through increased market prices for electricity. In 2021, the Biden Administration introduced new targets aimed at reducing economy-wide net GHG emissions by 50 to 52 percent from 2005 levels by 2030. In addition, the Administration set a goal to reach 100 percent carbon pollution-free electricity by 2035. To achieve these targets the Administration may implement new regulations targeting GHG emissions from existing fossil fuel-fired power plants. While the precise nature and implications of any new regulations are uncertain, such regulations could impose substantial costs on and impact the operations of our utility business, which may materially impact our financial condition, operating results and liquidity. In addition to complying with legislation and regulation, we could be subject to litigation related to climate change. In recent years, there has been an increase in litigation against electric utilities and fossil fuel producers. If OTP were subjected to such litigation, the costs of such litigation could be significant and an adverse outcome could require substantial capital expenditures, changes in operations and possible payment of penalties or damages which could affect our financial condition, operating results and liquidity if the costs are not recoverable in rates or covered by insurance. To the extent investors view climate change, fossil fuel combustion and GHG emissions as a financial risk, our stock price or our ability to access capital markets on favorable terms and conditions could be adversely impacted. Violations of extensive legal and regulatory compliance requirements could have a negative impact on our business and results of operations. We are subject to an extensive legal and regulatory framework imposed under federal and state laws and regulatory agencies, including the FERC and the NERC. We could be subject to potential financial penalties for compliance violations. Our transmission systems and electric generation facilities are subject to the NERC mandatory reliability standards, including cybersecurity standards. If a serious reliability incident were to occur, it could have a material effect on our operations or financial results. Some states have the authority to impose substantial penalties in the event of non-compliance. We attempt to mitigate the risk of regulatory penalties through formal training. However, there is no guarantee our compliance program will be sufficient to ensure against violations. In addition, energy policy initiatives at the state or federal level could increase incentives for distributed generation, or authorize municipal utility formation or acquisition of service territory, or local initiatives could introduce generation or distribution requirements that could change the current integrated utility model. These laws and regulations significantly influence our operations and may affect our ability to recover costs from our customers. We are required to have numerous permits, licenses, approvals and certificates from the agencies and other organizations that regulate our business. We believe we have obtained the necessary approvals for our existing operations and that our business is conducted in accordance with applicable laws and regulatory requirements; however, we are unable to predict the impact on our operating results from the future regulatory activities of any of these agencies and other organizations. Changes in regulations or the imposition of additional regulations could have a material adverse impact on our financial condition, operating results and liquidity. Our transmission and generation facilities could be vulnerable to cyber and physical attack. OTP owns electric transmission and generation facilities subject to mandatory and enforceable standards advanced by the NERC. These bulk electric system facilities provide the framework for the electrical infrastructure of OTPs service territory and interconnected systems, the operation of which is dependent on information technology systems. Further, the information systems that operate OTPs electric system are interconnected to external networks. Parties that wish to disrupt the U.S. bulk power system or OTPs operations could view OTPs computer systems, software or networks as attractive targets for cyber-attack. In addition, OTPs generation and transmission facilities are spread throughout a large service territory. These facilities could be subject to physical attack or vandalism that could disrupt OTPs operations or conceivably the regional or U.S. bulk power system. OTP is subject to mandatory cybersecurity and physical security regulatory requirements. OTP implements the NERC standards for operating its transmission and generation assets and remains abreast of best practices within the business and the utility industry to protect its computers and computer-controlled systems from outside attack. We rely on industry-accepted security measures and technology to securely maintain confidential and proprietary information necessary for the operation of our systems. In an effort to reduce the likelihood and severity of cyber intrusions, we have cybersecurity processes and controls and disaster recovery plans designed to protect and preserve the confidentiality, integrity and availability of data and systems. We also take prudent and reasonable steps to protect the physical security of our generation and transmission facilities. However, all these measures and technology may not adequately prevent security breaches, ransomware attacks or other cyber-attacks, or enable us to recover effectively from such a breach or attack. Any significant interruption or failure of our information systems or any significant breach of security due to cyber-attacks, hacking or internal security breaches or physical attack of our generation or transmission facilities could adversely affect our business and our financial condition, operating results and liquidity. Our generating facilities and transmission assets are subject to operational risks that could result in unscheduled outages and increased costs. The operation of electric generating facilities and transmission assets involves many risks including facility shutdowns due to equipment or process failures; aging equipment and sourcing replacement parts; labor disputes; operator error; catastrophic events such as fires, explosions and floods; the dependence on a specific fuel source; increased costs or delayed receipt of materials due to supply chain disruptions; and the risk of performance below expected levels of output or efficiency. We could be subject to costs associated with any unexpected failure to produce or deliver power, including failures caused by a breakdown or forced outage, as well as damages to facilities or other assets. We rely on a limited number of suppliers to provide coal and coal transportation to our facilities. A failure to perform by any of these counterparties may arise due to liquidity challenges or insolvency, operational deficiencies or other circumstances such as severe weather or natural disasters, which could impact our ability to provide service to our customers or require us to seek alternative sources for these products and services, if available, which could lead to increased costs adversely impacting our financial condition, operating results and liquidity. Joint ownership of coal-fired generation facilities could impact our ability to manage changing regulations and economic conditions. We own our coal-fired generation facilities jointly with other co-owners with varying ownership interests in such facilities. Our ability to make determinations on our IRP in order to best navigate changing environmental regulations and economic conditions may be impacted by our rights and obligations under the co-ownership agreements and related agreements, and our ability to reconcile a divergence in the interests of OTP and the co-owners of these generation facilities. Such a divergence could impair our ability to effectively manage these changing conditions to meet our strategic objectives and could adversely impact our financial condition, operating results and liquidity. We are subject to risks associated with energy markets. Our electric business is subject to the risks associated with energy markets, including market supply and changing energy prices. If we are faced with shortages in market supply, we may be unable to fulfill our contractual obligations to our retail, wholesale and other customers at previously anticipated costs. This could force us to obtain alternative energy or fuel supplies at higher costs, or suffer increased liabilities for unfulfilled contractual obligations. Any significantly higher than expected energy or fuel costs could negatively affect our financial condition, operating results and liquidity. MANUFACTURING SEGMENT RISKS The price and availability of raw materials could adversely impact our operating results. The companies in our Manufacturing segment use a variety of raw materials in the products they manufacture including, among others, steel, aluminum, and polystyrene and other plastics resins. The price and availability of the raw materials used in our manufacturing processes are based on global supply and demand conditions, which can create volatile pricing and supply disruptions as conditions change. Federal trade policies, including imposed tariffs, can also impact prices for these raw materials. If we are unable to pass cost increases through to our customers or are unable to procure adequate or timely raw material inputs for use in our manufacturing processes, our financial condition, operating results and liquidity could be negatively impacted. Additionally, a certain amount of residual material (scrap) is a by-product of the manufacturing and production processes used by our manufacturing companies. Declines in commodity prices for these scrap materials due to weakened demand or excess supply can negatively impact the profitability of our manufacturing companies as it reduces their ability to mitigate the cost associated with excess material. Competition from foreign and domestic manufacturers could affect the revenues and earnings of our manufacturing businesses. Our manufacturing businesses are subject to intense competition from foreign and domestic manufacturers, many of whom have broader product lines, greater distribution capabilities, greater capital resources, larger marketing, research and development personnel and facilities, and other capabilities. Our ability to compete on product performance, competitive pricing, technological innovation and customer service is critical to our ongoing success. If we are unable to compete in these and potentially other areas, our business and financial condition, operating results and liquidity could be adversely impacted. Economic conditions in the end markets in which our customers operate could have an adverse impact on our operating results and liquidity . Our manufacturing businesses derive a large amount of their revenues from customers in the following industry sectors: recreational vehicle/powersports, lawn and garden, construction, agriculture, energy and horticulture. Factors affecting any of these industries in general could adversely affect our operating results as growth in our operating revenues is largely dependent on the growth of our customers businesses in their respective industries. These factors include: seasonality of demand for our customers products which may cause our manufacturing capacity to be underutilized for periods of time; our customers failure to successfully market their products, gain or retain widespread commercial acceptance of their products or compete effectively in their industries; loss of market share for our customers products which may lead our customers to reduce or discontinue purchasing our products and components and to reduce prices, thereby exerting pricing pressure on us; economic conditions in the markets in which our customers operate, the United States, in particular, including recessionary periods such as a global economic downturn; our customers decisions to bring the production of components in-house that have traditionally been outsourced to us; and product design changes or manufacturing process changes that may reduce or eliminate demand for the components we supply. We expect future sales will continue to depend on the success of our customers. If economic conditions or demand for our customers products deteriorates, we may experience a material adverse effect on our financial condition, operating results and liquidity. Our business may be adversely affected if we are not able to maintain our manufacturing, engineering and technological expertise. The markets for our manufacturing businesses are characterized by changing technology and evolving process development. The continued success of our businesses will depend on our ability to: maintain technological leadership in our industry; implement new and expand on current robotics, automation and tooling technologies; and anticipate or respond to changes in manufacturing processes in a cost-effective and timely manner. We may be unable to develop the capabilities required by our customers in the future. The emergence of new technologies, industry standards or customer requirements may render our equipment, inventory or processes obsolete or noncompetitive. We may be required to acquire new technologies and equipment to remain competitive. The acquisition and implementation of new technologies and equipment may require us to incur significant expense and capital investment, which could reduce our margins and affect our operating results. When we establish or acquire new facilities, we may not be able to maintain or develop our manufacturing, engineering and technological expertise due to a lack of trained personnel, ineffective training of new staff or technical difficulties with machinery. Failure to anticipate and adapt to customers changing technological needs and requirements and to maintain manufacturing, engineering and technological expertise may have material adverse effects on our financial condition, operating results and liquidity. PLASTICS SEGMENT RISKS Changes in PVC resin prices could negatively affect our plastics business. The PVC pipe industry is highly sensitive to commodity raw material pricing volatility. Historically, when resin prices were rising or stable, margins and sales volumes were higher and when resin prices were falling, sales volumes and margins were lower. Changes in PVC resin prices can negatively affect PVC pipe prices, profit margins on PVC pipe sales and the value of our finished goods inventory. Periodic shortages of PVC resin coupled with robust domestic and global demand for PVC resin led to significantly increased resin pricing throughout 2021 and the first half of 2022, which resulted in higher input costs in our Plastics segment during these years. Resin prices started to decline in the last half of 2022 and we anticipate resin prices will moderate in 2023 as these market conditions normalize. Our operating results could be impacted by the timing and degree to which resin prices stabilize. Our plastics operations are highly dependent on a limited number of vendors and a limited supply of PVC resin and other materials. We rely on a limited number of vendors to supply the PVC resin used in our plastics business. In 2022 we sourced all of our PVC resin needs from two vendors. In addition, the supply of PVC resin may be limited primarily due to manufacturing capacity and the limited availability of raw material components. Most U.S. resin production plants are located in the Gulf Coast region. This could increase the risk of a shortage of resin in the event of a hurricane, other extreme weather events and other natural disasters in that region. The loss of a key vendor or any interruption or delay in the availability or supply of PVC resin could disrupt our ability to deliver our plastic products, cause customers to cancel orders or require us to incur additional expenses to obtain PVC resin from alternative sources, if such sources were available. Although PVC resin is the most significant raw material input in our PVC pipe manufacturing process, we also use certain other materials, such as stabilizers, gaskets, lumber, banding and others in the process of manufacturing and shipping our PVC pipe products. We generally source these materials from a limited number of suppliers and any significant supply chain constraints or disruptions related to these materials could also disrupt our ability to manufacture or ship products and could result in increased costs. We compete against many other manufacturers of PVC pipe and manufacturers of alternative products. Customers may not distinguish our products from those of our competitors. The plastic pipe industry is fragmented and competitive due to the number of producers and the fungible nature of the product. We compete not only against other plastic pipe manufacturers, but also against ductile iron, steel and concrete pipe manufacturers. Due to shipping costs, competition is usually regional instead of national in scope and the principal areas of competition are a combination of price, service, warranty and product performance. Our inability to compete effectively in each of these areas and to distinguish our plastic pipe products from competing products may adversely affect the financial performance of our plastics businesses. External factors beyond our control could cause fluctuations in demand for our PVC pipe products and changes in our prices and margins, which could adversely impact our operating results. Our PVC pipe products, sold through distributors and wholesalers, are primarily used in municipal and rural water projects, wastewater projects, storm drainage systems and reclamation systems. External factors beyond our control can cause volatility in raw material costs, demand for our products, sales prices, and deterioration in operating margins. These factors can magnify the impact of economic cycles on our business and results of operations. Examples of external factors include: general economic conditions including housing and construction markets which can be cyclical; increases in interest rates; severe weather and natural disasters; governmental regulation in the United States; funding shortages for municipal water and wastewater projects; and pandemics and other public health threats. Our financial results in 2021 and 2022 were impacted by unique market conditions within the PVC pipe industry, including a significant increase in the price of PVC resin, and periodic shortages of certain additives and ingredients used in the manufacturing of PVC pipe which limited the manufacturing of PVC pipe. Strong demand for PVC pipe along with limited manufacturing output led to low inventories across the industry. The combination of these factors resulted in extraordinary growth in earnings and cash flows from our Plastic segment in these years. As these industry conditions begin to normalize in 2023 and beyond, we anticipate our operating results and cash flows will moderate, returning to more stable levels. Our operating results and cash flows could be impacted by the timing under which conditions normalize and the level of stabilized resin and PVC pipe prices. GENERAL RISK FACTORS Economic conditions could negatively impact our businesses. Our businesses are affected by local, national and worldwide economic conditions, including the impact of inflation, tightening of credit in financial markets, economic recessions or other changes in economic conditions. Our businesses may be adversely affected by decreases in the general level of economic activity, such as decreases in business and consumer spending. A decline in the level of economic activity and uncertainty regarding energy and commodity prices could adversely affect our results of operations and our future growth. Inflationary pressures may lead to rising material and commodity costs and increased labor costs. Our operating results and liquidity would be adversely impacted if we were unable to recover these increased costs from our customers. Tightening of credit in financial markets could adversely affect the ability of customers to finance purchases of our goods and services, resulting in decreased orders, cancelled or deferred orders, slower payment cycles, and increased bad debt and customer bankruptcies. If we are unable to achieve the organic growth we expect, our financial performance may be adversely affected. We expect much of our growth in the next few years will come from major capital investments at existing companies. To achieve the organic growth we expect, we must have access to the capital markets, be successful with capital expansion programs related to organic growth, develop new products and services, expand our markets and increase efficiencies in our businesses. Competitive and economic factors could adversely affect our ability to do this. If we are unable to achieve and sustain consistent organic growth, we will be less likely to meet our earnings growth targets, which may adversely affect the market price of our common shares. The economic effects of the coronavirus (COVID-19) pandemic and any other epidemic or pandemic, and measures taken to reduce and slow the spread of the disease could adversely impact our business. The outbreak and global spread of COVID-19 has had widespread impacts on society, economies, financial markets and businesses everywhere since early 2020. The COVID-19 pandemic has impacted our business operations, including our employees, customers, construction contractors, suppliers and vendors, and some uncertainty in the nature and degree of the continued effects over time still remains. In 2022, our business was impacted by supply chain disruptions and labor shortages resulting from the pandemic, and the associated costs and inflation related thereto. The extent to which COVID-19 impacts our business going forward, if at all, remains uncertain. We continue to monitor developments involving our workforce, customers, construction contractors, suppliers and vendors and take steps to mitigate against additional impacts, but given the unprecedented and evolving nature of these circumstances, we cannot predict the full extent of the impact that COVID-19 will have on our operating results, financial condition and liquidity. A future widespread outbreak of an infectious disease, which affects a large percentage of the population regionally, nationally, or globally could impact our business operations, including our employees, customers, construction contractors, suppliers and vendors, and could impact our operating results, financial condition and liquidity. ##TABLE_START

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ITEM 1. BUSINESS Pinnacle West Pinnacle West is a holding company that conducts business through its subsidiaries. We derive essentially all of our revenues and earnings from our wholly-owned subsidiary, APS. APS is a vertically-integrated electric utility that provides either retail or wholesale electric service to most of the State of Arizona, with the major exceptions of about one-half of the Phoenix metropolitan area, the Tucson metropolitan area and Mohave County in northwestern Arizona. Pinnacle Wests other subsidiaries are El Dorado, BCE and 4CA. Additional information related to these subsidiaries is provided later in this report. Our reportable business segment is our regulated electricity segment, which consists of traditional regulated retail and wholesale electricity businesses (primarily electric service to Native Load customers) and related activities, and includes electricity generation, transmission, and distribution. BUSINESS OF ARIZONA PUBLIC SERVICE COMPANY APS currently provides electric service to approximately 1.3 million customers. We own or lease 6,340 MW of regulated generation capacity and we hold a mix of both long-term and short-term purchased power agreements for additional capacity, including a variety of agreements for the purchase of renewable energy. During 2022, no single purchaser or user of energy accounted for more than 2.4% of our electric revenues. Table of Contents The following map shows APSs retail service territory, including the locations of its generating facilities and principal transmission lines. Table of Contents Energy Sources and Resource Planning To serve its customers, APS obtains power through its various generation stations and through purchased power agreements. Resource planning is an important function necessary to meet Arizonas future energy needs. APSs sources of energy by type used to supply energy to Native Load customers during 2022 were as follows: *Renewables include energy from wind, solar, geothermal, biomass, DG, and solar PPAs. The share of APSs energy supply being derived from clean resources is 51%, which includes energy from nuclear, renewables and DSM. BCE also has acquired minority ownership positions in two wind farms that achieved commercial operation in 2020. Both wind farms deliver power under long-term PPAs. See Business of Other Subsidiaries Bright Canyon Energy below for information regarding BCEs investments. Clean Energy Focus Initiatives In response to climate change, the entire electric utility industry, as well as the global economy, is in the midst of a profound transition to clean energy and a new low-carbon economy. APS has undertaken a number of initiatives to reduce carbon, including renewable energy procurement and development, and promotion of programs and rates that promote energy conservation, renewable energy use, and energy efficiency. See Energy Sources and Resource Planning Current and Future Resources below for details of these plans and initiatives. APS currently has a diverse portfolio of renewable resources, Table of Contents including solar, wind, geothermal, biogas, and biomass. In addition, in January 2020, APS announced its Clean Energy Commitment, a three-pronged approach aimed at ultimately eliminating carbon-emitting resources from its electric generation resource portfolio. APSs clean energy goals consist of three parts: a 2050 goal to provide 100% clean, carbon-free electricity; a 2030 target of achieving a resource mix that is 65% clean energy, with 45% of the generation portfolio coming from renewable energy; and a commitment to end APSs use of coal-fired generation by 2031. Among other strategies, APS intends to achieve these goals through various methods such as relying on Palo Verde, the nations largest producer of carbon-free energy; increasing clean energy resources, including renewables; developing energy storage; ceasing the use of coal-generated electricity; managing demand with a modern interactive grid; promoting customer technology and energy efficiency; and optimizing regional resources. Management takes into consideration climate change and other environmental risks in its strategy development, business planning, and enterprise risk management processes. See Item 7, Managements Discussion and Analysis of Financial Condition and Results of Operations for additional information about APSs Clean Energy Commitment. Over this same period of time, APS also intends to harden its infrastructure in order to improve climate resiliency, which involves system and operational improvements aimed at reducing the impact of extreme weather events and other climate-related disruptions upon APSs operations. Among other resiliency strategies, APS anticipates increasing investments in a modern and more flexible electricity grid with advanced distribution technologies. APS plans to continue its comprehensive forest management programs aimed at reducing wildfires, as those risks become compounded by shorter, drier winters and longer, hotter summers as a result of climate change. APS prepares an annual inventory of GHG emissions from its operations. For APSs operations involving fossil-fuel electricity generation and electricity transmission and distribution, APSs annual GHG inventory is reported to EPA under the EPA GHG Reporting Program. APS also voluntarily tracks APSs GHG emissions arising from APS operations. In addition to reporting to the EPA, we publicly report Scope 1, 2 and 3 GHG emissions. This data is then communicated to the public in Pinnacle Wests annual Corporate Responsibility Report as performance data and in CDP Reports, which are available on our website (www.pinnaclewest.com/corporate-responsibility). The reports provide information related to the Company and its approach to sustainability and its workplace and environmental performance. The information on Pinnacle Wests website, including Corporate Responsibility Reports and CDP Reports, is not incorporated by reference into or otherwise a part of this report. Generation Facilities APS has ownership interests in or leases the nuclear, gas, oil, coal, and solar generating facilities as well as energy storage facilities described below. For additional information regarding these facilities, see Item 2. Nuclear Palo Verde Generating Station Palo Verde is a 3-unit nuclear power plant located approximately 50 miles west of Phoenix, Arizona. APS operates the plant and owns 29.1% of Palo Verde Units 1 and 3 Table of Contents and approximately 17% of Unit 2. In addition, APS leases approximately 12.1% of Unit 2, resulting in a 29.1% combined ownership and leasehold interest in that unit. APS has a total entitlement from Palo Verde of 1,146 MW. Palo Verde Leases In 1986, APS entered into agreements with three separate lessor trust entities in order to sell and lease back approximately 42% of its share of Palo Verde Unit 2 and certain common facilities. The leaseback was originally scheduled to expire at the end of 2015 and contained options to renew the leases or to purchase the leased property for fair market value at the end of the lease terms. On July 7, 2014, APS exercised the fixed rate lease renewal options. The exercise of the renewal options originally resulted in APS retaining the assets through 2023 under one lease and 2033 under the other two leases. On April 1, 2021, APS executed an amendment relating to the lease agreement with the term ending in 2023. The amendment extends the lease term for this lease through 2033 and changes the lease payment. As a result of this amendment, APS will now retain the assets through 2033 under all three lease agreements. At the end of the lease renewal periods, APS will have the option to purchase the leased assets at their fair market value, extend the leases for up to two years, or return the assets to the lessors. See Note 17 for additional information regarding the Palo Verde Unit 2 sale leaseback transactions. Palo Verde Operating Licenses Operation of each of the three Palo Verde Units requires an operating license from the NRC. The NRC issued full power operating licenses for Unit 1 in June 1985, Unit 2 in April 1986, and Unit 3 in November 1987, and issued renewed operating licenses for each of the three units in April 2011, which extended the licenses for Units 1, 2, and 3 to June 2045, April 2046, and November 2047, respectively. Palo Verde Fuel Cycle The participant owners of Palo Verde are continually identifying their future nuclear fuel resource needs and negotiating arrangements to fill those needs. The fuel cycle for Palo Verde is comprised of the following stages: mining and milling of uranium ore to produce uranium concentrates; conversion of uranium concentrates to uranium hexafluoride; enrichment of uranium hexafluoride; fabrication of fuel assemblies; utilization of fuel assemblies in reactors; and storage and disposal of spent nuclear fuel. The Palo Verde participants have contracted for 100% of Palo Verdes requirements for uranium concentrates through 2028 and 48% through 2029; 100% of Palo Verdes requirements for conversion services through 2030 and 40% through 2031; 100% of Palo Verdes requirements for enrichment services through 2026 and 28% for 2027; and 100% of Palo Verdes requirements for fuel fabrication through 2027 for Unit 2 and Unit 1 and 2028 for Unit 3. Spent Nuclear Fuel and Waste Disposal The Nuclear Waste Policy Act of 1982 (NWPA) required the DOE to begin to accept, transport, and dispose of spent nuclear fuel and high-level waste generated by the nations nuclear power plants by 1998. The DOEs obligations are reflected in a contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste (the Standard Contract) with each nuclear power plant. The DOE failed to begin accepting spent nuclear fuel by 1998. The DOE had planned to meet its NWPA and Standard Contract disposal obligations by designing, licensing, constructing, and operating a permanent geologic repository at Yucca Mountain, Nevada. In June 2008, the DOE submitted its Yucca Mountain construction authorization application to the NRC, but in March 2010, the DOE filed a motion to dismiss with prejudice the Yucca Mountain construction Table of Contents authorization application. Several legal proceedings followed challenging DOEs withdrawal of its Yucca Mountain construction authorization application and the NRCs cessation of its review of the Yucca Mountain construction authorization application, which were consolidated into one matter at the U.S. Court of Appeals for the District of Columbia Circuit (the D.C. Circuit). Following the D.C. Circuits August 2013 order, the NRC issued two volumes of the safety evaluation report developed as part of the Yucca Mountain construction authorization application. Publication of these volumes do not signal whether or when the NRC might authorize construction of the repository. APS is directly involved in legal proceedings related to the DOEs failure to meet its statutory and contractual obligations regarding acceptance of spent nuclear fuel and high-level waste. APS Lawsuit for Breach of Standard Contract In December 2003, APS, acting on behalf of itself and the Palo Verde participants, filed a lawsuit against the DOE in the United States Court of Federal Claims (Court of Federal Claims) for damages incurred due to the DOEs breach of the Standard Contract. The Court of Federal Claims ruled in favor of APS and the Palo Verde participants in October 2010 and awarded damages to APS and the Palo Verde participants for costs incurred through December 2006. On December 19, 2012, APS, acting on behalf of itself and the participant owners of Palo Verde, filed a second breach of contract lawsuit against the DOE in the Court of Federal Claims. This lawsuit sought to recover damages incurred due to the DOEs breach of the Standard Contract for failing to accept Palo Verdes spent nuclear fuel and high-level waste from January 1, 2007 through June 30, 2011, as it was required to do pursuant to the terms of the Standard Contract and the NWPA. On August 18, 2014, APS and the DOE entered into a settlement agreement, stipulating to a dismissal of the lawsuit and payment by the DOE to the Palo Verde owners for certain specified costs incurred by Palo Verde during the period January 1, 2007, through June 30, 2011. In addition, the settlement agreement provided APS with a method for submitting claims and getting recovery for costs incurred through December 31, 2016, which was extended to December 31, 2022. An additional extension is currently pending. APS has submitted eight claims pursuant to the terms of the August 18, 2014 settlement agreement for eight separate time periods during July 1, 2011 through June 30, 2021. The DOE has approved and paid $123.9 million for these claims (APSs share is $36 million). The amounts recovered were primarily recorded as adjustments to a regulatory liability and had no impact on reported net income. In accordance with the 2017 Rate Case Decision, this regulatory liability is being refunded to customers. See Note 3. On October 31, 2022, APS filed its ninth claim pursuant to the terms of the August 18, 2014, settlement agreement in the amount of $14.3 million (APSs share is $4.2 million). In February 2023, the DOE approved this claim. Waste Confidence and Continued Storage On June 8, 2012, the D.C. Circuit issued its decision on a challenge by several states and environmental groups of the NRCs rulemaking regarding temporary storage and permanent disposal of high-level nuclear waste and spent nuclear fuel. The petitioners had challenged the NRCs 2010 update to the agencys waste confidence decision and temporary storage rule (Waste Confidence Decision). The D.C. Circuit found that the NRCs evaluation of the environmental risks from spent nuclear fuel was deficient, and therefore remanded the Waste Confidence Decision update for further action consistent with National Environmental Policy Act. In September 2013, the NRC issued its draft Generic Environmental Impact Statement (GEIS) to support an updated Waste Confidence Decision. On August 26, 2014, the NRC approved a final rule on the environmental effects of continued storage of spent nuclear fuel. Renamed as the Continued Storage Rule, the NRCs decision adopted the findings of the GEIS regarding the environmental impacts of storing spent fuel at any reactor site after the reactors licensed period of operations. As a result, those generic impacts do not need to be Table of Contents re-analyzed in the environmental reviews for individual licenses. The final Continued Storage Rule was subject to continuing legal challenges before the NRC and the Court of Appeals. In June 2016, the D.C. Circuit issued its final decision, rejecting all remaining legal challenges to the Continued Storage Rule. On August 8, 2016, the D.C. Circuit denied a petition for rehearing. Palo Verde has sufficient capacity at its on-site independent spent fuel storage installation (ISFSI) to store all of the nuclear fuel that will be irradiated during the initial operating license period, which ends in December 2027. Additionally, Palo Verde has sufficient capacity at its on-site ISFSI to store a portion of the fuel that will be irradiated during the period of extended operation, which ends in November 2047. If uncertainties regarding the United States governments obligation to accept and store spent fuel are not favorably resolved, APS will evaluate alternative storage solutions that may obviate the need to expand the ISFSI to accommodate all of the fuel that will be irradiated during the period of extended operation. Nuclear Decommissioning Costs APS currently relies on an external sinking fund mechanism to meet the NRC financial assurance requirements for decommissioning its interests in Palo Verde Units 1, 2 and 3. The decommissioning costs of Palo Verde Units 1, 2 and 3 are currently included in APSs ACC jurisdictional rates. Decommissioning costs are recoverable through a non-bypassable system benefits charge (paid by all retail customers taking service from the APS system). Based on current nuclear decommissioning trust asset balances, site specific decommissioning cost studies, anticipated future contributions to the decommissioning trusts, and return projections on the asset portfolios over the expected remaining operating life of the facility, we are on track to meet the current site-specific decommissioning costs for Palo Verde at the time the units are expected to be decommissioned. See Note 18 for additional information about APSs nuclear decommissioning trusts. Palo Verde Liability and Insurance Matters See Palo Verde Generating Station Nuclear Insurance in Note 10 for a discussion of the insurance maintained by the Palo Verde participants, including APS, for Palo Verde. Natural Gas and Oil Fueled Generating Facilities APS has six natural gas power plants located throughout Arizona, consisting of Redhawk, located near Palo Verde; Ocotillo, located in Tempe (discussed below); Sundance, located in Coolidge; West Phoenix, located in southwest Phoenix; Saguaro, located north of Tucson; and Yucca, located near Yuma. Several of the units at Yucca run on either gas or oil. APS has two oil-only power plants: Fairview, located in the town of Douglas, Arizona and Yucca GT-4 in Yuma, Arizona. APS owns and operates each of these plants with the exception of one oil-only combustion turbine unit and one oil and gas steam unit at Yucca that are operated by APS and owned by the Imperial Irrigation District. APS has a total entitlement from these plants of 3,573 MW. A portion of the gas for these plants is financially hedged up to three years in advance of purchasing and that position is converted to a physical gas purchase one month prior to delivery. APS has long-term gas transportation agreements with three different companies, some of which are effective through 2049. Fuel oil is acquired under short-term purchases delivered by truck directly to the power plants. Ocotillo was originally a 330 MW 4-unit gas plant located in Tempe. In early 2014, APS announced a project to modernize the plant, which involved retiring two older 110 MW steam units, adding five 102 MW combustion turbines, and maintaining two existing 55 MW combustion turbines. In total, this increased the capacity of the site by 290 MW to 620 MW. The Ocotillo modernization project was completed in 2019. Table of Contents Coal Fueled Generating Facilities Four Corners Four Corners is located in the northwestern corner of New Mexico and was originally a 5-unit coal-fired power plant. APS owns 100% of Units 1, 2 and 3, which were retired as of December 30, 2013. APS operates the plant and owns 63% of Four Corners Units 4 and 5. APS has a total entitlement from Four Corners of 970 MW. Additionally, 4CA, a wholly-owned subsidiary of Pinnacle West, owned 7% of Units 4 and 5 from July 2016 through July 2018 following its acquisition of El Pasos interest in these units described below. As part of APSs Clean Energy Commitment, APS has committed to cease using coal-fired generation as part of its portfolio of electricity generating resources, including Four Corners, by 2031. NTEC, a company formed by the Navajo Nation to own the mine that serves Four Corners and develop other energy projects, is the coal supplier for Four Corners. The Four Corners co-owners executed a long-term agreement for the supply of coal to Four Corners from July 2016 through 2031 (the 2016 Coal Supply Agreement). El Paso, a 7% owner of Units 4 and 5 of Four Corners, did not sign the 2016 Coal Supply Agreement. Under the 2016 Coal Supply Agreement, APS agreed to assume the 7% shortfall obligation. On February 17, 2015, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Pasos 7% interest in each of Units 4 and 5 of Four Corners. 4CA purchased the El Paso interest on July 6, 2016. The purchase price was immaterial in amount, and 4CA assumed El Pasos reclamation and decommissioning obligations associated with the 7% interest. On June 29, 2018, 4CA and NTEC entered into an asset purchase agreement providing for the sale to NTEC of 4CAs 7% interest in Four Corners. NTEC assumed 4CAs reclamation and decommissioning obligations associated with the 7% interest. The sale transaction closed on July 3, 2018. NTEC purchased the 7% interest at 4CAs book value, approximately $70 million and paid the purchase price over four years pursuant to a secured interest-bearing promissory note, which was paid in full as of June 30, 2022. In connection with the sale, Pinnacle West guaranteed certain obligations that NTEC will have to the other owners of Four Corners, such as NTECs 7% share of capital expenditures and operating and maintenance expenses. Pinnacle Wests guarantee is secured by a portion of APSs payments to be owed to NTEC under the 2016 Coal Supply Agreement. APS, on behalf of the Four Corners participants, negotiated amendments to an existing facility lease with the Navajo Nation, which extends the Four Corners leasehold interest from 2016 to 2041. The Navajo Nation approved these amendments in March 2011. The effectiveness of the amendments also required the approval of the DOI, as did a related federal rights-of-way grant. A federal environmental review was undertaken as part of the DOI review process and culminated in the issuance by DOI of a record of decision on July 17, 2015, justifying the agency action to extend the life of the plant and the adjacent mine. In June 2021, APS and the owners of Four Corners entered into an agreement that would allow Four Corners to operate seasonally at the election of the owners beginning in fall 2023, subject to the necessary governmental approvals and conditions associated with changes in plant ownership. Under seasonal operation, one generating unit would be shut down during seasons when electricity demand is reduced, such as the winter and spring. The other unit would remain online year-round, subject to market conditions as well as planned maintenance outages and unplanned outages. APS anticipates that it will elect not to begin seasonal operation in November 2023, unless market conditions change. Table of Contents Cholla Cholla was originally a 4-unit coal-fired power plant, which is located in northeastern Arizona. APS operates the plant and owns 100% of Cholla Units 1, 2 and 3. PacifiCorp owns Cholla Unit 4, and APS operated that unit for PacifiCorp. On

September 11, 2014, APS announced that it would close Cholla Unit 2 and cease burning coal at the other APS-owned units (Units 1 and 3) at the plant by the mid-2020s, if EPA approved a compromise proposal offered by APS to meet required environmental and emissions standards and rules. On April 14, 2015, the ACC approved APSs plan to retire Unit 2, without expressing any view on the future recoverability of APSs remaining investment in the Unit. APS closed Unit 2 on October 1, 2015. Following the closure of Unit 2, APS has a total entitlement from Cholla of 381 MW. In early 2017, EPA approved a final rule incorporating APSs compromise proposal, which took effect for Cholla on April 26, 2017. In December 2019, PacifiCorp notified APS that it planned to retire Cholla Unit 4 by the end of 2020 and the unit ceased operation in December 2020. APS has committed to end the use of coal at its remaining Cholla units by 2025. APS purchases all of Chollas coal requirements from a coal supplier that mines all of the coal under long-term leases of coal reserves with the federal and state governments and private landholders. The Cholla coal contract runs through 2024. In addition, APS has a coal transportation contract that runs through 2024. Navajo Plant The Navajo Plant was a 3-unit coal-fired power plant located in northern Arizona. Salt River Project operated the plant and APS owned a 14% interest in Units 1, 2 and 3. APS had a total entitlement from the Navajo Plant of 315 MW. The Navajo Plant site is leased from the Navajo Nation and is also subject to an easement from the federal government. The co-owners of the Navajo Plant and the Navajo Nation agreed that the Navajo Plant would remain in operation until December 2019 under the existing plant lease. The co-owners and the Navajo Nation executed a lease extension on November 29, 2017, which allowed for decommissioning activities to begin after the plant ceased operations in November 2019. APS is currently recovering depreciation and a return on the net book value of its interest in the Navajo Plant over its previously estimated life through 2026. APS will seek continued recovery in rates for the book value of its remaining investment in the plant. See Note 3 for details related to the resulting regulatory asset plus a return on the net book value as well as other costs related to retirement and closure, which are still being assessed and which may be material. See Note 10 for information regarding APSs coal mine reclamation obligations related to these coal-fired plants. Solar Facilities APS developed utility scale solar resources through the 180 MW ACC-approved AZ Sun Program, investing approximately $675 million in this program. These facilities are owned by APS and are located in multiple locations throughout Arizona. In addition to the AZ Sun Program, APS developed the 44 MW Red Rock Solar Plant, which it owns and operates. Two of our large customers purchase renewable energy credits from APS that are equivalent to the amount of renewable energy that Red Rock is projected to generate. APS owns and operates more than thirty small solar systems around the state. Together they have the capacity to produce approximately 4 MW of renewable energy. This fleet of solar systems includes a 3 MW facility located at the Prescott Airport and 1 MW of small solar systems in various locations across Table of Contents Arizona. APS has also developed solar photovoltaic distributed renewable energy systems installed as part of the

Community Power Project in Flagstaff, Arizona. The Community Power Project, approved by the ACC on April 1, 2010, was a pilot program through which APS owns, operates, and receives energy from approximately 1 MW of solar photovoltaic distributed renewable energy systems located within a certain test area in Flagstaff, Arizona. The pilot program is now complete and as part of the 2017 Rate Case Decision, the participants have been transferred to the Solar Partner Program described below. Additionally, APS owns 13 MW of solar photovoltaic systems installed across Arizona through the ACC-approved Schools and Government Program. In December 2014, the ACC voted that it had no objection to APS implementing an APS-owned rooftop solar research and development program aimed at learning how to efficiently enable the integration of rooftop solar and battery storage with the grid. The first stage of the program, called the Solar Partner Program, placed 8 MW of residential rooftop solar on strategically selected distribution feeders in an effort to maximize potential system benefits, as well as made systems available to limited-income customers who could not easily install solar through transactions with third parties. The second stage of the program, which included an additional 2 MW of rooftop solar and energy storage, placed two energy storage systems sized at 2 MW on two different high solar penetration feeders to test various grid-related operation improvements and system interoperability, and was in operation by the end of 2016. The costs for this program have been included in APSs rate base as part of the 2017 Rate Case Decision. In the 2017 Rate Case Decision, the ACC also approved the APS Solar Communities program. APS Solar Communities (formerly AZ Sun II) is a three-year program authorizing APS to spend $10 million to $15 million in capital costs each year to install utility-owned DG systems on low to moderate income residential homes, non-profit entities, Title I schools, and rural government facilities. The 2017 Rate Case Decision provided that all operations and maintenance expenses, property taxes, marketing and advertising expenses, and the capital carrying costs for this program will be recovered through the RES. Currently, APS has installed 11 MW of DG systems under the APS Solar Communities program. In the 2019 Rate Case decision, the ACC authorized APS to spend $20 million to $30 million in capital costs for the APS Solar Communities program each year for a period of three years from the effective date of the decision. Energy Storage APS deploys a number of advanced technologies on its system, including energy storage. Energy storage provides capacity, improves power quality, can be utilized for system regulation and, in certain circumstances, be used to defer certain traditional infrastructure investments. Energy storage also aids in integrating renewable generation by storing excess energy when system demand is low and renewable production is high and then releasing the stored energy during peak demand hours later in the day and after sunset. APS is utilizing grid-scale energy storage projects to meet customer reliability requirements, increase renewable utilization, and further our understanding of how storage works with other advanced technologies and the grid. In 2018, APS issued a request for proposal (RFP) for approximately 106 MW of energy storage to be located at up to five of its AZ Sun sites. Based upon its evaluation of the RFP responses, APS decided to expand the initial phase of battery deployment to 141 MW by adding a sixth AZ Sun site. These battery storage facilities are currently expected to be in service during the first quarter of 2023. On August 2, 2021, APS executed a contract for an additional 60 MW of utility-owned energy storage to be located on APSs AZ Sun sites. This contract, with a 2023 in-service date, will complete the addition of storage on current APS-owned utility-scale solar facilities. Table of Contents Additionally, in February 2019, APS signed two 20-year PPAs for energy storage totaling 150 MW. These PPAs were subject to ACC approval in order to allow for cost recovery through the PSA. APS received the requested ACC approval on January 12, 2021, and service under the agreements is expected to begin in 2023. In December 2020, APS issued two RFPs (collectively, the December 2020 RFPs). As a result of the December 2020 RFPs, APS executed four 20-year PPAs for resources that include energy storage: (a) two PPAs for standalone energy storage resources totaling 300 MW; and (b) two PPAs for solar plus storage resources totaling 275 MW. The PPAs are also subject to ACC approval to enable cost recovery through the PSA. APS received the requested ACC approval for three out of four of the projects on December 16, 2021 and on April 13, 2022 for the remaining project. Service under the agreements is expected to begin in 2023 and 2024. In May 2022, APS issued an RFP to address resource needs for 2025 and beyond (the 2022 RFP). As a result of the 2022 RFP, as of January 2023, APS has executed a 20-year PPA for solar plus storage resources totaling 300 MW. The PPA is subject to ACC approval to enable cost recovery through the PSA, which was requested in December 2022 and approved in February 2023. Service under this agreement is expected to begin in 2025. APS currently plans to install more than 1,200 MW of energy storage by 2025, including the energy storage projects under PPAs and AZ Sun retrofits described above. The remaining energy storage is expected to be made up of resources solicited through current and future RFPs. The following table summarizes the resources in APSs energy storage portfolio that are in operation and under development as of December 31, 2022. Agreements for the development and completion of future resources are subject to various conditions. ##TABLE_START Net Capacity in Operation (MW) Net Capacity Planned / Under Development (MW) APS Owned Energy Storage 201 PPAs Energy Storage 1,025 Residential Energy Storage 19(a) 7 Total Energy Storage Portfolio 19 1,233 ##TABLE_END(a) This includes 18.5 MW of APS customer-owned batteries and 0.2 MW of APS-owned residential batteries. Renewable Energy Portfolio To date, APS has a diverse portfolio of existing and planned renewable resources totaling 3,894 MW, including solar, wind, geothermal, biomass and biogas. Of this portfolio, 2,418 MW are currently in operation and 1,476 MW are under contract for development or are under construction. Renewable resources in operation include 264 MW of facilities owned by APS, 736 MW of long-term purchased power agreements, and an estimated 1,418 MW of customer-sited, third-party owned distributed energy resources. Table of Contents As previously discussed, in May 2022, APS issued an RFP to address resource needs for 2025 and beyond. The 2022 RFP solicits competitive proposals for approximately 1,000

MW to 1,500 MW of resources, including up to 600 MW to 800 MW of renewable resources to meet the needs of 2025 and 2026 while also considering resources that can be online as late as 2027. The 2022 RFP stopped accepting bids on July 15, 2022, and APS sent notifications to shortlisted bidders on September 23, 2022. As a result of the 2022 RFP, and as of December 31, 2022, APS has signed a PPA for 300 MW of solar plus energy storage resources and a PPA for 216 MW of wind resources. Once APS secures those important resources and closes out the 2022 RFP, APS intends to issue APSs next RFP to address future resource needs. APSs strategy to achieve its RES requirements includes executing purchased power contracts for new facilities, ongoing development of distributed energy resources and procurement of new facilities to be owned by APS. See Energy Sources and Resource Planning Generation Facilities Solar Facilities above for information regarding APS-owned solar facilities and Energy Sources and Resource Planning Generation Facilities Energy Storage above for more information regarding APS-owned energy storage facilities. The following table summarizes APSs renewable energy sources currently in operation and under development as of December 31, 2022. Agreements for the development and completion of future resources are subject to various conditions, including successful siting, permitting and interconnection of the projects to the electric grid. ##TABLE_START Location Actual/ Target Commercial Operation Date Term (Years) Net Capacity In Operation (MW AC) Net Capacity Planned/Under Development (MW AC) APS Owned Solar: AZ Sun Program: Paloma Gila Bend, AZ 2011 17 Cotton Center Gila Bend, AZ 2011 17 Hyder Phase 1 Hyder, AZ 2011 11 Hyder Phase 2 Hyder, AZ 2012 6 Chino Valley Chino Valley, AZ 2012 20 Hyder II Hyder, AZ 2013 14 Foothills Yuma, AZ 2013 38 Gila Bend Gila Bend, AZ 2014 36 Luke AFB Glendale, AZ 2015 11 Desert Star Buckeye, AZ 2015 10 Subtotal AZ Sun Program 180 Multiple Facilities AZ Various 4 Red Rock Red Rock, AZ 2016 44 Agave Solar Arlington, AZ 2023 150 Distributed Energy: APS Owned (a) AZ Various 36 Total APS Owned 264 150 Purchased Power Agreements Solar: Solana Gila Bend, AZ 2013 30 250 RE Ajo Ajo, AZ 2011 25 5 Sun E AZ 1 Prescott, AZ 2011 30 10 Saddle Mountain Tonopah, AZ 2012 30 15 Badger Tonopah, AZ 2013 30 15 ##TABLE_ENDTable of Contents ##TABLE_START Gillespie Maricopa County, AZ 2013 30 15 CO Bar Solar A Coconino County, AZ 2023 18 80 CO Bar Solar B Coconino County, AZ 2023 18 80 Mesquite Solar 5 Tonopah, AZ 2023 20 60 Sunstreams 3 Arlington, AZ 2024 20 215 Sunstreams 4 Arlington, AZ 2025 20 300 Wind: Aragonne Mesa Santa Rosa, NM 2022 20 200 High Lonesome Mountainair, NM 2009 30 100 Perrin Ranch Wind Williams, AZ 2012 25 99 Chevelon Butte Winslow, AZ 2023 20 238 Chevelon Butte II Winslow, AZ 2024 20 216 Geothermal: Salton Sea Imperial County, CA 2006 23 10 Biomass: Snowflake Snowflake, AZ 2008 25 14 Biogas: NW Regional Landfill Surprise, AZ 2012 20 3 Total Purchased Power Agreements 736 1,189 Distributed Energy Solar (b) Third-party Owned AZ Various 1,385 137 Agreement 1 Bagdad, AZ 2011 25 15 Agreement 2 AZ 2011-2012 20-21 18 Total Distributed Energy 1,418 137 Total Renewable Portfolio 2,418 1,476 ##TABLE_END(a) Includes Flagstaff Community Power Project, APS

School and Government Program, APS Solar Partner Program, and APS Solar Communities Program. (b) Includes rooftop solar facilities owned by third parties. DG is produced in DC and is converted to AC for reporting purposes. Purchased Power Contracts In addition to its own available generating capacity, APS purchases electricity under various arrangements, including long-term contracts and purchases through short-term markets to supplement its owned or leased generation and hedge its energy requirements. A portion of APSs purchased power expense is netted against wholesale sales on the Consolidated Statements of Income. See Note 15. APS continually assesses its need for additional capacity resources to assure system reliability. In addition, APS has also entered into several PPAs for energy storage. See Business of Arizona Public Service Company Energy Sources and Resource Planning Energy Storage above for details on our energy storage PPAs. Table of Contents Purchased Power Capacity APSs purchased power capacity under long-term contracts as of December 31, 2022, is summarized in the table below. All capacity values are based on net capacity unless otherwise noted. ##TABLE_START Type Dates Available Capacity (MW) Purchase Agreement (a) Year-round through June 14, 2023 45 Demand Response Agreement Summer seasons through 2025 75 Tolling Agreement May 1 through October 31, 2021-2027 463 Tolling Agreement Summer seasons from Summer 2020 through Summer 2025 565 Tolling Agreement June 1 through September 30, 2020-2026 570 Renewable Energy (b) Various 736 ##TABLE_END(a) Up to 45 MW of capacity is available; however, the amount of electricity available to APS under this agreement is based in large part on customer demand and is adjusted annually. (b) Does not include MW of capacity planned or under development. Renewable energy purchased power agreements are described in detail below under Current and Future Resources Renewable Energy Standard Renewable Energy Portfolio. Current and Future Resources Current Demand and Reserve Margin Electric power demand is generally seasonal. In Arizona, demand for power peaks during the hot summer months. APSs 2022 peak one-hour demand on its electric system was recorded on July 11, 2022, at 7,587 MW, compared to the 2021 peak of 7,580 MW recorded on June 18, 2021. APSs reserve margin at the time of the 2022 peak demand, calculated using system load serving capacity, was 13%. For 2023, due to expiring purchased power contracts, APS is procuring market resources to maintain its minimum 15% planning reserve criteria. Future Resources and Resource Plan ACC rules require utilities to develop 15-year Integrated Resource Plans (IRP) which describe how the utility plans to serve customer load in the plan timeframe. The ACC reviews each utilitys IRP to determine if it meets the necessary requirements and whether it should be acknowledged. Based on an ACC decision, APS was originally required to file its IRP by April 1, 2020. On February 20, 2020, the ACC extended the deadline for all utilities to file their IRPs from April 1, 2020, to June 26, 2020. On June 26, 2020, APS filed its final IRP. On July 15, 2020, the ACC extended the schedule for final ACC review of utility IRPs to February 2021. In February 2022, the ACC acknowledged APSs IRP. The ACC also approved certain amendments to the IRP process, including, setting an EES of

1.3% of retail sales annually (averaged over a three-year period) and a demand-side resource capacity of 35% of 2020 peak demand by January 1, 2030. Due to current projected future resource needs and load forecasts, APS continues to need to develop or acquire additional capacity. APS intends to file its next IRP later in 2023. See Business of Arizona Public Service Company Energy Sources and Resource Planning Clean Energy Focus Initiatives and Business of Arizona Public Service Company Energy Sources and Resource Planning Energy Storage above for information regarding future plans for energy storage. See Business of Arizona Public Service Company Energy Sources and Resource Planning Generation Facilities Coal-Fueled Generating Facilities above for information regarding plans for Cholla, Four Corners and the Navajo Plant. Table of Contents Energy Imbalance Market Wholesale Market In 2016, APS began to participate in the Energy Imbalance Market (EIM), a voluntary, real-time optimization market operated by the CAISO. The EIM allows for rebalancing supply and demand in 15-minute blocks and dispatching generation every five minutes, instead of the traditional one-hour blocks. APS continues to expect that its participation in EIM will lower its fuel and purchased-power costs, improve situational awareness for system operations in the Western Interconnection power grid, and improve integration of APSs renewable resources. APS is in discussions with the EIM operator, CAISO, and other EIM participants about the feasibility of creating a voluntary day-ahead market to achieve more cost savings and use the regions renewable resources more efficiently. APS also is in discussions with Southwest Power Pool, a market operator developing a day-ahead and real-time market for the Western Interconnection. In addition, APS is participating in the Western Resource Adequacy Program administered by the Western Power Pool. These efforts are driven by three objectives of reducing customer cost, improving reliability, and incorporating more clean energy on APSs system. Energy Modernization Plan On July 30, 2020, the ACC Staff issued final draft energy rules, which proposed 100% of retail kWh sales from clean energy resources by the end of 2050. Nuclear power was defined as a clean energy resource. The proposed rules also required 50% of retail energy served be renewable by the end of 2035. On November 13, 2020, the ACC approved a final draft energy rules package which required additional procedural steps in the rulemaking process. In June 2021, the ACC adopted clean energy rules based on a series of ACC amendments to the final energy rules. The adopted rules require 100% clean energy by 2070 and the following interim standards for carbon reduction from baseline carbon emissions level: 50% reduction by December 31, 2032; 65% reduction by December 31, 2040; 80% reduction by December 31, 2050, and 95% reduction by December 31, 2060. Since the adopted clean energy rules differed substantially from the original Recommended Order and Opinion, supplemental rulemaking procedures were required before the rules could become effective. On January 26, 2022, the ACC reversed its prior decision and declined to send the final draft energy rules through the rulemaking process. Instead, the ACC opened a new docket to consider All-Source RFP requirements and the IRP process. During the August 2022 ACC Open Meeting, Commissioners voted to postpone a decision on the

All-Source RFP and IRP rulemaking package until 2023. APS cannot predict the outcome of this matter. See Note 3 for additional information related to these energy rules. Renewable Energy Standard In 2006, the ACC adopted the RES. Under the RES, electric utilities that are regulated by the ACC must supply an increasing percentage of their retail electric energy sales from eligible renewable resources, including solar, wind, biomass, biogas, and geothermal technologies. The renewable energy requirement is 13% of retail electric sales in 2023 and increases annually until it reaches 15% in 2025. A component of the RES is focused on stimulating development of distributed renewable energy systems. Accordingly, under the RES, an increasing percentage of that requirement must be supplied from distributed energy resources. This distributed renewable energy requirement, which was waived by the ACC as a part of APSs 2023 RES Implementation Plan, would have been 30% of the overall RES requirement of 13% in 2023. On June 7, 2021, the ACC approved the 2021 RES Implementation Plan. On July 1, 2021, APS filed its 2022 RES Implementation Plan, which was subsequently amended on December 9, 2021. On May 18, 2022, the ACC approved the 2022 RES Implementation Plan, including an Table of Contents amendment requiring a stakeholder working group to convene and develop a community solar program for the Commissions consideration at a future date. On September 23, 2022, APS filed a community solar proposal in compliance with the ACC order that was informed by a stakeholder working group. APS is proposing a small, pilot scale program size of up to 140 MW that would be selected through a competitive RFP. The ACC has not yet ruled on the proposal. However, on November 10, 2022, the ACC approved a bifurcated community solar process, directing ACC Staff to develop a statewide policy through additional stakeholder involvement and establishing a separate evidentiary hearing to define other policy components. The community solar program was deferred to the ACCs Hearing Division so that a formal evidentiary hearing could be held to consider issues of substance related to community solar. APS cannot predict the outcomes of these future activities. On July 1, 2022, APS filed its 2023 RES Implementation Plan, and on November 10, 2022, the ACC approved the 2023 RES Implementation Plan, including APSs requested waiver of the distributed energy requirement for 2023. The following table summarizes the RES requirement standard and its timing: ##TABLE_START 2023 2025 RES (inclusive of distributed energy) as a percent of retail electric sales 13% 15% Percent of RES to be supplied from distributed renewable energy resources (a) 30% 30% ##TABLE_END(a) The distributed renewable energy requirement has been waived for 2023. On April 21, 2015, the RES rules were amended to require utilities to report on all eligible renewable resources in their service territory, irrespective of whether the utility owns renewable energy credits associated with such renewable energy. The rules allow the ACC to consider such information in determining whether APS has satisfied the requirements of the RES. Demand Side Management On January 1, 2011, Arizona regulators adopted an EES of 22% cumulative annual energy savings by 2020 to increase energy efficiency and other DSM programs encouraging customers to conserve energy, while incentivizing utilities to aid in these efforts that ultimately reduce the demand for energy. APS achieved the 22% EES in 2021. See Note 3 for information regarding energy efficiency, other DSM obligations and the Energy Modernization Plan. Competitive Environment and Regulatory Oversight Retail The ACC regulates APSs retail electric rates and its issuance of securities. The ACC must also approve any significant transfer or encumbrance of APSs property used to provide retail electric service and approve or receive prior notification of certain transactions between Pinnacle West, APS, and their respective affiliates. See Note 3 for information regarding ACCs regulation of APSs retail electric rates. APS is subject to varying degrees of competition from other investor-owned electric and gas utilities in Arizona (such as Southwest Gas Corporation), as well as cooperatives, municipalities, electrical districts, and similar types of governmental or non-profit organizations. In addition, some customers, particularly industrial and large commercial customers, may own and operate generation facilities to meet Table of Contents some or all of their own energy requirements. This practice is becoming more popular with customers installing or having installed products such as rooftop solar panels to meet or supplement their energy needs. On May 9, 2013, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. The ACC subsequently opened a docket for this matter and received comments from a number of interested parties on the considerations involved in establishing retail electric deregulation in the state. One of these considerations was whether various aspects of a deregulated market, including setting utility rates on a market basis, would be consistent with the requirements of the Arizona Constitution. On September 11, 2013, after receiving legal advice from the ACC Staff, the ACC voted 4-1 to close the current docket and await full Arizona Constitutional authority before any further examination of this matter. The motion approved by the ACC also included opening one or more new dockets in the future to explore options to offer more rate choices to customers and innovative changes within the existing cost-of-service regulatory model that could include elements of competition. On November 17, 2018, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. On July 1 and July 2, 2019, ACC Staff issued a report and initial proposed draft rules regarding possible modifications to the ACCs retail electric competition rules. On February 10, 2020, two ACC Commissioners filed two sets of draft proposed retail electric competition rules. On February 12, 2020, ACC Staff issued its second report regarding possible modifications to the ACCs retail electric competition rules. During a July 15, 2020 ACC Staff meeting, the ACC Commissioners discussed the possible development of a retail competition pilot program, but no action was taken. The ACC continues to discuss matters related to retail electric competition, including the potential for additional buy-through programs or other pilot programs. In April 2022, the Arizona Legislature passed and the Governor signed a bill that repealed the electric deregulation law that had been in place in Arizona since 1998. APS cannot predict what impact, if any, this change will have on APS. On August 4, 2021, Green Mountain Energy filed an application seeking a certificate of convenience and necessity to allow it to provide competitive electric generation service in Arizona. Green Mountain Energy has requested that the ACC grant it the ability to provide competitive service in APSs and Tucson Electric Power Companys certificated service territories and proposes to deliver a 100% renewable energy product to residential and general service customers in those service territories. APS opposes Green Mountain Energys application and intends to intervene to contest it. On November 3, 2021, the ACC submitted questions to the Office of the Arizona Attorney General, Civil Litigation Division, Consumer Protection Advocacy Section (Attorney General) requesting legal opinions related to a number of issues surrounding retail electric competition and the ACCs ability to issue competitive certificates convenience and necessity. On November 26, 2021, the Administrative Law Judge issued a procedural order indicating it would not be appropriate to set a schedule until the Attorney General has provided insights on the applicable law. On October 28, 2021, an ACC Commissioner docketed a letter directing ACC Staff and interested stakeholders to design a 200-300 MW pilot program that would allow residential and small commercial customers of APS to elect a competitive electricity supplier. The letter also states that similar programs should be designed for other Arizona regulated electric utilities. APS cannot predict the outcome of these future activities. Table of Contents Wholesale FERC regulates rates for wholesale power sales and transmission services. See Note 3 for information regarding APSs transmission rates. During 2022, approximately 11.6% of APSs electric operating revenues resulted from such sales and services. APSs wholesale activity primarily consists of managing fuel and purchased power supplies to serve retail customer energy requirements. APS also sells, in the wholesale market, its generation output that is not needed for APSs Native Load and, in doing so, competes with other utilities, power marketers and independent power producers. Additionally, subject to specified parameters, APS hedges both electricity and natural gas. The majority of these activities are undertaken to mitigate risk in APSs portfolio. Transmission and Delivery APS continues to work closely with customers, stakeholders, and regulators to identify and plan for transmission needs that support new customers, system reliability, access to markets and clean energy development. The capital expenditures table presented in the Liquidity and Capital Resources section of Managements Discussion and Analysis of Financial Condition and Results of Operations in Item 7 of this report includes new APS transmission projects, along with other transmission costs for upgrades and replacements, including those for data center and semi-conductor manufacturing development. APS is also working to establish and expand advanced grid technologies throughout its service territory to provide long-term benefits both to APS and its customers. APS is strategically deploying a variety of technologies that are intended to allow customers to better manage their energy usage, minimize system outage durations and frequency, enable customer choice for new customer sited technologies, and facilitate greater cost savings to APS through improved reliability and the automation of certain delivery functions. Environmental Matters Climate Change Legislative Initiatives. There have been no recent successful attempts by Congress to pass legislation that would regulate GHG emissions, and it is unclear at this time whether legislation regulating or limiting utility-sector GHG emissions under consideration in the 118th Congress will become law. In the event climate change legislation ultimately passes, the actual economic and operational impact of such legislation on APS depends on a variety of factors, none of which can be fully known until a law is written, enacted, and the specifics of the resulting program are established. These factors include, without limitation, the terms of the legislation with regard to allowed GHG emissions; the cost to reduce emissions; in the event a cap-and-trade program is established, whether any permitted emissions allowances will be allocated to source operators free of cost or auctioned (and, if so, the cost of those allowances in the marketplace) and whether offsets and other measures to moderate the costs of compliance will be available; and, in the event of a carbon tax, the amount of the tax per pound of carbon dioxide (CO_2) equivalent emitted. In addition to federal legislative initiatives, state-specific initiatives may also impact our business. While Arizona has no pending legislation regulating GHGs, the California legislature enacted AB 32 and SB 1368 in 2006 to address GHG emissions. In October 2011, the California Air Resources Board approved final regulations that established a state-wide cap on GHG emissions beginning on January 1, 2013, and established a GHG allowance trading program under that cap. The first phase of the program, which applies to, among other entities, importers of electricity, commenced on January 1, 2013. Under the program, entities selling electricity into California, including APS, must hold carbon allowances to cover Table of Contents GHG emissions associated with electricity sales into California from outside the state. APS is authorized to recover the cost of these carbon allowances through the PSA. Regulatory Initiatives. In 2009, EPA determined that GHG emissions endanger public health and welfare. As a result of this endangerment finding, EPA determined that the Clean Air Act required new regulatory requirements for new and modified major GHG emitting sources, including power plants. APS will generally be required to consider the impact of GHG emissions as part of its traditional New Source Review analysis for new major sources and major modifications to existing plants. On June 19, 2019, EPA took final action on its proposals to repeal EPAs 2015 Clean Power Plan (CPP) and replace those regulations with a new rule, the Affordable Clean Energy (ACE) regulations. EPA originally finalized the CPP on August 3, 2015, and such rules would have had far broader impact on the electric power sector than the ACE regulations. On January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE regulations and remanded them back to EPA to develop new existing power plant carbon regulations consistent with the courts ruling. That decision, which endorsed an expansive view of the federal Clean Air Act consistent with EPAs 2015 CPP, was subsequently reversed by the U.S. Supreme Court on June 30, 2022. While the current administration has expressed its intent to develop new carbon emission regulations governing existing power plants sometime in 2023, such action will be constrained by the U.S. Supreme Courts decision that the CPP violated the Clean Air Act. Nonetheless, we cannot at this time predict the outcome of pending EPA rulemaking proceedings related to carbon emissions from existing power plants. Other environmental rules that could involve material compliance costs include those related to effluent limitations, the ozone national ambient air quality standards (NAAQS) and other rules or matters involving the Clean Air Act, Clean Water Act, Endangered Species Act, RCRA, Superfund, the Navajo Nation, and water supplies for our power plants. The financial impact of complying with current and future environmental rules could jeopardize the economic viability of our coal plants or the willingness or ability of power plant participants to fund any required equipment upgrades or continue their participation in these plants. The economics of continuing to own certain resources, particularly our fossil-fuel powered plants, may deteriorate, warranting early retirement of those plants, which may result in asset impairments. APS would seek recovery in rates for the book value of any remaining investments in the plants as well as other costs related to early retirement but cannot predict whether it would obtain such recovery. EPA Environmental Regulation Regional Haze Rules . In 1999, EPA announced regional haze rules to reduce visibility impairment in national parks and wilderness areas. The rules require states (or, for sources located on tribal land, EPA) to determine what pollution control technologies constitute the BART for certain older major stationary sources, including fossil-fuel fired power plants. EPA subsequently issued the Clean Air Visibility Rule, which provides guidelines on how to perform a BART analysis. Final regulations imposing BART requirements have now been imposed on each APS coal-fired power plant. Four Corners was required to install new pollution controls to comply with BART, while similar pollution control installation requirements were not necessary for Cholla. Cholla. In early 2017, EPA approved a final rule containing a revision to Arizonas State Implementation Plan (SIP) for Cholla that implemented BART requirements for this facility, which did not require the installation of any new pollution control capital improvements. In conjunction with the closure of Cholla Unit 2 in 2015, APS has committed to ceasing coal combustion within Units 1 and 3 by Table of Contents April 2025. PacifiCorp retired Cholla Unit 4 at the end of 2020. See Cholla in Note 3 for information regarding future plans for Cholla and details related to the resulting regulatory asset. Four Corners . Based on EPAs final standards, APSs 63% share of the cost of required BART controls for Four Corners Units 4 and 5 was approximately $400 million, which has been incurred. See Note 3 for information regarding the related rate recovery. In addition, APS and El Paso entered into an asset purchase agreement providing for the purchase by APS, or an affiliate of APS, of El Pasos 7% interest in Four Corners Units 4 and 5. 4CA purchased the El Paso interest on July 6, 2016. NTEC purchased the interest from 4CA on July 3, 2018. The cost of the pollution controls related to the 7% interest is approximately $45 million, which was assumed by NTEC through its purchase of the 7% interest. Coal Combustion Waste. On December 19, 2014, EPA issued its final regulations governing the handling and disposal of CCR, such as fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste under Subtitle D of the RCRA and establishes national minimum criteria for existing and new CCR landfills and surface impoundments and all lateral expansions. These criteria include standards governing location restrictions, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care, and recordkeeping, notification, and internet posting requirements. The rule generally requires any existing unlined CCR surface impoundment to stop receiving CCR and either retrofit or close, and further requires the closure of any CCR landfill or surface impoundment that cannot meet the applicable performance criteria for location restrictions or structural integrity. Such closure requirements are deemed forced closure or closure for cause of unlined surface impoundments and are the subject of recent regulatory and judicial activities described below. Since these regulations were finalized, EPA has taken steps to substantially modify the federal rules governing CCR disposal. While certain changes have been prompted by utility industry petitions, others have resulted from judicial review, court-approved settlements with environmental groups, and statutory changes to RCRA. The following lists the pending regulatory changes that, if finalized, could have a material impact as to how APS manages CCR at its coal-fired power plants: Following the passage of the Water Infrastructure Improvements for the Nation Act in 2016, EPA possesses authority to either authorize states to develop their own permit programs for CCR management or issue federal permits governing CCR disposal both in states without their own permit programs and on tribal lands. Although ADEQ has taken steps to develop a CCR permitting program, including supporting the passage of new state legislation providing ADEQ with appropriate permitting authority for CCR under the state solid waste management program, it is not clear when that program will be put into effect. On December 19, 2019, EPA proposed its own set of regulations governing the issuance of CCR management permits. The proposal remains pending. On March 1, 2018, as a result of a settlement with certain environmental groups, EPA proposed adding boron to the list of constituents that trigger corrective action requirements to remediate groundwater impacted by CCR disposal activities. Apart from a subsequent proposal issued on August 14, 2019, to add a specific, health-based groundwater protection standard for boron, EPA has yet to take action on this proposal. With respect to APSs Cholla facility, the Companys application for alternative closure was submitted to EPA on November 30, 2020. While EPA has deemed APSs application administratively complete, the Agencys approval remains pending. If granted, this application would allow the continued disposal of CCR within Chollas existing unlined CCR surface impoundments until the required date for ceasing coal-fired boiler operations in April 2025. This Table of Contents application will be subject to public comment and, potentially, judicial review. On January 11, 2022, EPA began issuing proposed decisions pursuant to this provision of the federal CCR regulations and APS anticipates receiving a proposed decision with respect to the Cholla facility in 2023. We cannot at this time predict the outcome of these regulatory proceedings or when the EPA will take final action on those matters that are still pending. Depending on the eventual outcome, the costs associated with APSs management of CCR could materially increase, which could affect APSs financial position, results of operations, or cash flows. APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. APS estimates that its share of incremental costs to comply with the CCR rule for Four Corners is approximately $30 million and its share of incremental costs to comply with the CCR rule for Cholla is approximately $16 million. The Navajo Plant disposed of CCR only in a dry landfill storage area. To comply with the CCR rule for the Navajo Plant, APSs share of incremental costs was approximately $1 million, which has been incurred. Additionally, the CCR rule requires ongoing, phased groundwater monitoring. As of October 2018, APS has completed the statistical analyses for its CCR disposal units that triggered assessment monitoring. APS determined that several of its CCR disposal units at Cholla and Four Corners will need to undergo corrective action. In addition, under the current regulations, all such disposal units must have ceased operating and initiated closure by April 11, 2021, at the latest (except for those disposal units subject to alternative closure). APS completed the assessments of corrective measures on June 14, 2019; however, additional investigations and engineering analyses that will support the remedy selection are still underway. In addition, APS will also solicit input from the public and host public hearings as part of this process. Based on the work performed to date, APS currently estimates that its share of corrective action and monitoring costs at Four Corners will likely range from $10 million to $15 million, which would be incurred over 30 years. The analysis needed to perform a similar cost estimate for Cholla remains ongoing at this time. As APS continues to implement the CCR rules corrective action assessment process, the current cost estimates may change. Given uncertainties that may exist until we have fully completed the corrective action assessment process, we cannot predict any ultimate impacts to the Company; however, at this time we do not believe the cost estimates for Cholla and any potential change to the cost estimate for Four Corners would have a material impact on our financial position, results of operations, or cash flows. Effluent Limitation Guidelines. On September 30, 2015, EPA finalized revised effluent limitation guidelines (ELG) establishing technology-based wastewater discharge limitations for fossil-fired EGUs. EPAs final regulation targets metals and other pollutants in wastewater streams originating from fly ash and bottom ash handling activities, scrubber activities, and coal ash disposal leachate. Based upon an earlier set of preferred alternatives, the final effluent limitations generally require chemical precipitation and biological treatment for flue gas desulfurization scrubber wastewater, zero discharge from fly ash and bottom ash handling, and impoundment for coal ash disposal leachate. On August 11, 2017, EPA announced that it would be initiating rulemaking proceedings to potentially revise the September 2015 ELGs. On September 18, 2017, EPA finalized a regulation postponing the earliest date on which compliance with the ELGs for these waste-streams would be required from November 1, 2018, until November 1, 2020. At this time, APSs National Pollutant Discharge Elimination System (NPDES) discharge permit for Four Corners contains a December 31, 2023, Table of Contents compliance deadline for achieving zero discharge of bottom ash transport waters. Nonetheless, on October 13, 2020, EPA published a final rule relaxing these zero discharge limitations for bottom ash handling water and allowing for approximately 10% of such wastewater to be discharged (on a volumetric, 30-day rolling average basis) under limited power plant operating scenarios. At this time, APS is pursuing a modification to the Four Corners NPDES discharge permit in order to implement the most recent ELG rulemaking. We cannot at this time predict the outcome of this permit modification proceeding, including any public commenting or permit appeal procedures. The Cholla facility does not require NPDES permitting. Ozone National Ambient Air Quality Standards. On October 1, 2015, EPA finalized revisions to the primary ground-level ozone NAAQS at a level of 70 parts per billion (ppb). Further, on December 23, 2020, EPA issued a final regulation retaining the current primary NAAQS for ozone, following a required scientific review process. With ozone standards becoming more stringent, our fossil generation units will come under increasing pressure to reduce emissions of NOx and volatile organic compounds, and to generate emission offsets for new projects or facility expansions located in ozone nonattainment areas. EPA was expected to designate attainment and nonattainment areas relative to the new 70 ppb standard by October 1, 2017. While EPA took action designating attainment and unclassifiable areas on November 6, 2017, the Agencys final action designating non-attainment areas was not issued until April 30, 2018. At that time, EPA designated the geographic areas containing Yuma and Phoenix, Arizona as in non-attainment with the 2015 70 ppb ozone NAAQS. The vast majority of APSs natural gas-fired EGUs are located in these jurisdictions. Areas of Arizona and the Navajo Nation where the remainder of APSs fossil-fuel fired EGU fleet is located were designated as in attainment. We anticipate that revisions to the SIPs and FIPs implementing required controls to achieve the new 70 ppb standard will be in place between 2023 and 2024. At this time, because proposed SIPs and FIPs implementing the revised ozone NAAQSs have yet to be released, APS is unable to predict what impact the adoption of these standards may have on the Company. APS will continue to monitor these standards as they are implemented within the jurisdictions affecting APS. Superfund-Related Matters. The Comprehensive Environmental Response Compensation and Liability Act (CERCLA or Superfund) establishes liability for the cleanup of hazardous substances found contaminating the soil, water, or air. Those who released, generated, transported to, or disposed of hazardous substances at a contaminated site are among the parties who are potentially responsible (each a PRP). PRPs may be strictly, jointly, and severally liable for clean-up. On September 3, 2003, EPA advised APS that EPA considers APS to be a PRP in the Motorola 52 nd Street Superfund Site, Operable Unit 3 (OU3) in Phoenix, Arizona. APS has facilities that are within this Superfund site. APS and Pinnacle West have agreed with EPA to perform certain investigative activities of the APS facilities within OU3. In addition, on September 23, 2009, APS agreed with EPA and one other PRP to voluntarily assist with the funding and management of the site-wide groundwater remedial investigation and feasibility study (RI/FS). The RI/FS for OU3 was finalized and submitted to EPA at the end of 2022. APS cannot predict the EPA s timing with respect to this matter . APS estimates that its cost related to this investigation and study is approximately $3 million. APS anticipates incurring additional expenditures in the future, but because the ultimate remediation requirements are not yet finalized by EPA, at the present time, expenditures related to this matter cannot be reasonably estimated. On August 6, 2013, the Roosevelt Irrigation District (RID) filed a lawsuit in Arizona District Court against APS and 24 other defendants, alleging that RIDs groundwater wells were contaminated by the release of hazardous substances from facilities owned or operated by the defendants. The lawsuit also alleges that, under Superfund laws, the defendants are jointly and severally liable to RID. The allegations against APS arise out of APSs current and former ownership of facilities in and around OU3. As part of a Table of Contents state governmental investigation into groundwater contamination in this area, on January 25, 2015, ADEQ sent a letter to APS seeking information concerning the degree to which, if any, APSs current and former ownership of these facilities may have contributed to groundwater contamination in this area. APS responded to ADEQ on May 4, 2015. On December 16, 2016, two RID environmental and engineering contractors filed an ancillary lawsuit for recovery of costs against APS and the other defendants in the RID litigation. That same day, another RID service provider filed an additional ancillary CERCLA lawsuit against certain of the defendants in the main RID litigation but excluded APS and certain other parties as named defendants. Because the ancillary lawsuits concern past costs allegedly incurred by these RID vendors, which were ruled unrecoverable directly by RID in November of 2016, the additional lawsuits do not increase APSs exposure or risk related to these matters. On April 5, 2018, RID and the defendants in that particular litigation executed a settlement agreement, fully resolving RIDs CERCLA claims concerning both past and future cost recovery. APSs share of this settlement was immaterial. In addition, the two environmental and engineering vendors voluntarily dismissed their lawsuit against APS and the other named defendants without prejudice. An order to this effect was entered on April 17, 2018. With this disposition of the case, the vendors may file their lawsuit again in the future. On August 16, 2019, Maricopa County, one of the three direct defendants in the ancillary service provider lawsuit, filed a third-party complaint seeking contribution for its liability, if any, from APS and 28 other third-party defendants. While this lawsuit remains pending, on September 30, 2022, the U.S. District Court for the District of Arizona granted partial summary judgment to the direct defendants for $20.6 million of the $21 million in CERCLA response costs claimed by the service provider. We are unable to predict the outcome of any further litigation related to the remaining response costs at issue in this litigation; however, we do not expect the outcome to have a material impact on our financial position, results of operations, or cash flows. On February 28, 2022, EPA provided APS with a request for information under CERCLA related to APSs Ocotillo power plant site located in Tempe, Arizona. In particular, EPA seeks information from APS regarding APSs use, storage, and disposal of substances containing per-and polyfluoroalkyl (PFAS) compounds at the Ocotillo power plant site in order to aid EPAs investigation into actual or threatened releases of PFAS into groundwater within the South Indian Bend Wash (SIBW) Superfund site. The SIBW

Superfund site includes the APS Ocotillo power plant site. APS filed its response to this information request on April 29, 2022. On January 17, 2023, EPA contacted APS to inform APS that it would be commencing on-site investigations within the SIBW site, including the Ocotillo power plant, and performing a remedial investigation and feasibility study related to potential PFAS impacts to groundwater over the next two to three years. At the present time, we are unable to predict the outcome of this matter and expenditures related to this matter cannot be reasonably estimated. Manufactured Gas Plant Sites. Certain properties which APS now owns or which were previously owned by it or its corporate predecessors were at one time sites of, or sites associated with, manufactured gas plants. APS is taking action to voluntarily remediate these sites. APS does not expect these matters to have a material adverse effect on its financial position, results of operations, or cash flows. Four Corners National Pollutant Discharge Elimination System Permit On July 16, 2018, several environmental groups filed a petition for review before the EPA Environmental Appeals Board (EAB) concerning the NPDES wastewater discharge permit for Four Corners, which was reissued on June 12, 2018. The environmental groups allege that the permit was reissued in contravention of several requirements under the Clean Water Act and did not contain required provisions concerning EPAs 2015 revised ELGs for steam-electric EGUs, 2014 existing-source Table of Contents regulations governing cooling-water intake structures, and effluent limits for surface seepage and subsurface discharges from coal-ash disposal facilities. To address certain of these issues through a reconsidered permit, EPA took action on December 19, 2018, to withdraw the NPDES permit reissued in June 2018. Withdrawal of the permit moots the EAB appeal, and EPA filed a motion to dismiss on that basis. The EAB thereafter dismissed the environmental group appeal on February 12, 2019. EPA then issued a revised final NPDES permit for Four Corners on September 30, 2019. Based upon a November 1, 2019, filing by several environmental groups, the EAB again took up review of the Four Corners NPDES Permit. Oral argument on this appeal was held on September 3, 2020, and the EAB denied the environmental group petition on September 30, 2020. While on January 22, 2021, the environmental groups filed a petition for review of the EABs decision with the U.S. Court of Appeals for the Ninth Circuit, the parties to this litigation (including APS) finalized a settlement on May 2, 2022. This settlement requires investigation of thermal wastewater discharges from Four Corners, administratively closes the litigation filed in January of 2021, and is not expected to have a material impact on APSs financial position, results of operations, or cash flows. Water Supply Based on a declaration from the U.S. Bureau of Reclamation, as of January 1, 2023, Arizonas supply of Colorado River water will be subject to a Tier 2a shortage. This shortage will result in a reduction to Arizonas share of the Colorado River water by 22 percent or 592,000-acre feet. This reduction, similar to the 2022 tier 1 shortage, will largely be felt by central Arizonas agricultural users, mainly in Pinal County. In light of pre-existing mitigation measures at the state level, the Tier 2a shortage is not expected at this time to materially impact water supplies for customers in APSs service territory, nor materially impact water supplies used by APSs fleet of generation resources. As drought conditions across the southwestern U.S. region continue to worsen, APS will monitor water availability necessary for continued Company operations and, as necessary, implement measures to mitigate risks associated with future Colorado River shortage declarations. Assured supplies of water are important for APSs generating plants. At the present time, APS has adequate water to meet its operating needs. The Four Corners region, in which Four Corners is located, has historically experienced drought conditions that may affect the water supply for the plants if adequate moisture is not received in the watershed that supplies the area. APS is continuing to work with area stakeholders to implement agreements to minimize the effect, if any, on future drought conditions that could have an impact on operations of its plants. Conflicting claims to limited amounts of water in the southwestern United States have resulted in numerous court actions, which, in addition to future supply conditions, have the potential to impact APSs operations. San Juan River Adjudication. Both groundwater and surface water in areas important to APSs operations have been the subject of inquiries, claims, and legal proceedings, which will require a number of years to resolve. APS is one of a number of parties in a proceeding, filed March 13, 1975, before the Eleventh Judicial District Court in New Mexico to adjudicate rights to a stream system from which water for Four Corners is derived. An agreement reached with the Navajo Nation in 1985, however, provides that if Four Corners loses a portion of its rights in the adjudication, the Navajo Nation will provide, for an agreed upon cost, sufficient water from its allocation to offset the loss. In addition, APS is a party to a water contract that allows the Company to secure water for Four Corners in the event of a water shortage Table of Contents and is a party to a shortage sharing agreement, which provides for the apportionment of water supplies to Four Corners in the event of a water shortage in the San Juan River Basin. Gila River Adjudication. A summons served on APS in early 1986 required all water claimants in the Lower Gila River Watershed in Arizona to assert any claims to water on or before January 20, 1987, in an action pending in Arizona Superior Court. Palo Verde is located within the geographic area subject to the summons. APSs rights and the rights of the other Palo Verde participants to the use of groundwater and effluent at Palo Verde are potentially at issue in this adjudication. As operating agent of Palo Verde, APS filed claims that dispute the courts jurisdiction over the Palo Verde participants groundwater rights and their contractual rights to effluent relating to Palo Verde. Alternatively, APS seeks confirmation of such rights. Several of APSs other power plants are also located within the geographic area subject to the summons, including a number of gas-fired power plants located within Maricopa and Pinal Counties. In November 1999, the Arizona Supreme Court issued a decision confirming that certain groundwater rights may be available to the federal government and Indian tribes. In addition, in September 2000, the Arizona Supreme Court issued a decision affirming the lower courts criteria for resolving groundwater claims. Litigation on both of these issues has continued in the trial court. In December 2005, APS and other parties filed a petition with the Arizona Supreme Court requesting interlocutory review of a September 2005 trial court order regarding procedures for determining whether groundwater pumping is affecting surface water rights. The Arizona Supreme Court denied the petition in May 2007, and the trial court is now proceeding with implementation of its 2005 order. No trial date concerning APSs water rights claims has been set in this matter. At this time, the lower court proceedings in the Gila River adjudication are in the process of determining the specific hydro-geologic testing protocols for determining which groundwater wells located outside of the subflow zone of the Gila River should be subject to the adjudication courts jurisdiction. A hearing to determine this jurisdictional test question was held in March 2018 in front of a special master, and a draft decision based on the evidence heard during that hearing was issued on May 17, 2018. The decision of the special master, which was finalized on November 14, 2018, accepts the proposed hydro-geologic testing protocols supported by APS and other industrial users of groundwater. A further ruling affirming this decision by the trial court judge overseeing the adjudication was issued on July 8, 2022. Further proceedings have been initiated to determine the specific hydro-geologic testing protocols for subflow depletion determinations. The determinations made in this final stage of the proceedings may ultimately govern the adjudication of rights for parties, such as APS, that rely on groundwater extraction to support their industrial operations. APS cannot predict the outcome of these proceedings. Little Colorado River Adjudication. APS has filed claims to water in the Little Colorado River Watershed in Arizona in an action pending in the Apache County, Arizona, Superior Court, which was originally filed on September 5, 1985. APSs groundwater resource utilized at Cholla is within the geographic area subject to the adjudication and, therefore, is potentially at issue in the case. APSs claims dispute the courts jurisdiction over its groundwater rights. Alternatively, APS seeks confirmation of such rights. No trial or pretrial proceedings have been scheduled for adjudication of APSs water right claims. The adjudication court is currently conducting a trial of federal reserved water right claims asserted by the Hopi Tribe and by the United States as trustee for the Tribe. In addition, the adjudication court has established a schedule for consideration of separate federal reserved water right claims asserted by the Navajo Nation and by the United States as trustee for the Nation. There is no established timeframe within which the adjudication court is expected to issue a final determination of water rights for the Hopi Tribe and the Navajo Nation, and any such final determination is likely to occur multiple years in the future. Table of Contents Although the above matters remain subject to further evaluation, APS does not expect that the described litigation will have a material adverse impact on its financial position, results of operations, or cash flows. Human Capital The Company seeks to attract the best employees, retain those employees, and create a safe, inclusive, and productive work environment for all employees. We believe the strength of our employees is one of the significant contributors to our Companys success. Human capital measures and objectives that the Company focuses on in retaining its talent and managing its business include the safety of our employees, career development, diversity, equity and inclusion, succession planning, hiring, voluntary turnover, compensation, benefits, employee experience, and engagement. Employee Safety Our work and our decisions are anchored in safety safety is the foundation of everything we do, and employee safety is our paramount responsibility as an employer. We develop safety practices and programs that ensure employees have safe and secure workplaces that allow them to perform at the highest levels. Our comprehensive safety programs and our focus on human and organizational performance and injury case management contribute significantly to our strong safety performance. As we continue to improve our safety performance, our ultimate goal remains serious injury reduction. Our employees are expected to do the right thing and are empowered to speak up when there are better or safer ways of doing business, including stopping work to reassess or improve safety. Safety committees operate in organizations throughout the Company, providing opportunities for employees to positively impact their local safety cultures and performance. Diversity, Equity, and Inclusion We believe that belonging matters. When we feel seen, heard, and valued, we can more effectively unite behind the APS Promise. Inclusion at the Company involves taking deliberate action to embrace the unique perspectives of each employee. We recognize that diversity of demographics, backgrounds and cultural perspective is a key driver for our success. Our internal diversity, equity, and inclusion team, supported by our Executive Diversity Inclusion Council as well as other groups, leads this commitment with an emphasis on diversity among employees, in the workplace, and through our community involvement, as well as an increased focus on attracting and retaining diverse talent. This focus extends to individual business units in the Company, which report on the diversity of their teams during management review meetings to build awareness and address gaps of workforce diversity. Our efforts to support and empower employees include a commitment to full inclusion of all our people. We have a robust, multi-year strategy for diversity, equity, and inclusion that focuses on eleven key areas, both internally- and externally-facing. In 2021, APS received recognition as winner of the Inclusive Workplace Award from Diversity Leadership Alliance and Arizona Society of Human Resource Management. The award recognizes APS as an Arizona corporation that leads by example, creating an inclusive environment in which employees can be their genuine, authentic selves, and partners on community outreach efforts and support. Each year since 2020, we have conducted company-wide executive listening sessions to provide employees with opportunities to be heard on their experiences at the Company. In 2019, we signed the UNITY Pledge in support of full inclusion and equality in employment, housing, and public Table of Contents accommodations for all Arizonans, including gay and transgender people. The UNITY Pledge reinforces our commitment to fostering an environment that recognizes our employees unique needs and celebrates the value of diverse perspectives. The Company sponsors ten employee network groups that are intended to create a sense of inclusion and belonging for employees. We continue to focus on hiring diverse employees as well as hiring employees from our veteran community. During 2022, 44% of external hires were ethnically or racially diverse, 40% were female and 7% were veterans. Additionally, as of December 31, 2022, 35% of our employees are ethnically or racially diverse, 26% are female, and 15% are veterans. Finally , as of December 31, 2022, 39% of the Companys officers are female, and 18% are ethnically or racially diverse. Succession Planning Through a strong focus on succession planning, we ensure that our Company is prepared to fill executive and other key leadership roles with capable, experienced employees. We continually revisit and revise succession plans to make certain that qualified individuals are in place to move into critical positions. We have strategically selected successors for our management team to lead our Company into the future with strong and sustainable performance. In addition, we assure that each business unit of the Company has talent management strategies and development plans to meet its future leadership needs. Effective succession planning helps us identify employees with leadership potential and also allows us to evaluate any gaps in education, skills and experience that need to be addressed to prepare those employees to move into leadership roles. At management review meetings, officers and directors review how business units are addressing succession planning, leadership opportunities, and retirement projections. Talent Strategy and Development We place significant focus on attracting and developing a skilled workforce. To attract and retain top talent, we provide formal professional development programs through blended learning education and leadership training. Our employees have access to a wide variety of training and development opportunities, including leadership academies, rotational programs, mentoring programs, industry certifications, and loaned executive programs. In 2022, we graduated 138 individuals from our three academies (Leadership Academy, Impact and Influence Academy, and Strategic Leadership Academy). Additionally, our Learning and Development organization was recognized as a top training organization, earnings an APEX Award from Training Magazine. Talent pipelines help sustain our skilled workforce needs. Pipeline strategies include our apprentice and rotational programs. Additionally, our recruiters target specific colleges and programs of study that we have identified as talent pipelines. In 2022, we hosted 54 summer interns with a diversity rate of 63%. Total Rewards Strategy In addition to our talent strategy, we place significant focus on our Total Rewards strategy for attracting, developing, and rewarding our highly skilled workforce. Our employees are important to the success and future of our organization and our customers experiences. At the Company, our pay and benefits, along with retirement, recognition, time off, career development and well-being, make up our Total Rewards program. It is an important part of the employee experience at the Company and supports Table of Contents personal well-being and professional satisfaction. We are committed to providing programs that matter to our employees throughout various life and career phases. Employee Engagement An annual employee experience survey and focused quarterly pulse-surveys, enable us to gather employee feedback, identify opportunities for improvement, and compare our performance to other companies. Through the surveys, we track our Employee Experience Index, a set of seven questions that encompass key elements of a positive employee experience, including recognition, career development possibilities, and pride in the organization. Based on survey results, business units and individual managers are encouraged to take meaningful actions to improve the employee experience. In response to past surveys, we have launched enterprise-wide initiatives focused on improving communication between employees and management as well as removing obstacles that prevent job success. Other initiatives driven by the survey have given employees more access to leadership and improved meeting efficiency. Our cross-functional Employee Engagement Council focuses on improving employee recognition across the organization. We work to ensure that a positive work environment is maintained for all employees. Through an outreach initiative, we obtain feedback from new hires regarding their employee experience. In 2019, we integrated our employee experience surveys with onboarding surveys and exit interviews. Bringing together these elements allows us to get a more complete picture of the experience of our employees, from the time they join the Company until they decide to leave. Table of Contents Company Culture In 2020, the Company launched the APS Promise, anchoring our commitment to our customers, community, and each other. The Promise explains our purpose, vision, and mission and the principles and behaviors that will empower us to achieve our strategic goals. It represents the opportunity to build on our cultural strengths and develop new behaviors to enable our future success. BUSINESS OF OTHER SUBSIDIARIES Bright Canyon Energy On July 31, 2014, Pinnacle West announced its creation of a wholly-owned subsidiary, BCE. BCEs strategy is to develop, own, operate and acquire energy infrastructure in a manner that leverages the Companys core expertise in the electric energy industry. As of December 31, 2022, BCE had total assets of approximately $115.3 million. In 2014, BCE formed a 50/50 joint venture with BHE U.S. Transmission LLC, a subsidiary of Berkshire Hathaway Energy Company. The joint venture, named TransCanyon, is pursuing independent electric transmission opportunities within the 11 U.S. states that comprise the Western Interconnection, excluding opportunities related to transmission service that would otherwise be provided under the tariffs of the retail service territories of the venture partners utility affiliates. Table of Contents On December 20, 2019, BCE acquired minority ownership positions in two wind farms under development by Tenaska Energy, Inc. and Tenaska Energy Holdings, LLC, the 242 MW Clear Creek wind farm in Missouri (Clear Creek) and the 250 MW Nobles 2 wind farm in Minnesota (Nobles 2). Clear Creek achieved commercial operation in May 2020 and Nobles 2 achieved commercial operation in December 2020. Both wind farms deliver power under long-term PPAs. BCE indirectly owns 9.9% of Clear Creek and 5.1% of Nobles 2. Tenaska Clear Creek Wind, LLC, the developer, owner, and operator of the Clear Creek wind farm, has disputed the proposed cost allocation of system upgrades related to connecting the Clear Creek wind farm to the transmission system and filed a complaint with FERC on May 21, 2021, which was denied on September 9, 2022. Subsequently, Tenaska Clear Creek Wind, LLC filed with FERC a request for rehearing and a motion for stay of the September 9, 2022 order. On October 7, 2022, the request for rehearing was denied by FERC. FERC has not ruled on the motion for stay. Clear Creek has filed a Petition for Review with the U.S. Court of

Appeals and Motion for Stay Pending Appeal, both of which are still pending. Tenaska Clear Creek Wind, LLC filed a second complaint with FERC on May 25, 2022, alleging that the wind farm was being curtailed in a discriminatory manner. The May 25, 2022 Complaint was denied by FERC on December 15, 2022 and Tenaska Clear Creek Wind, LLC requested Rehearing of the denial on January 13, 2023. Due to the disputed system upgrades and the related curtailment, the Clear Creek wind farm has experienced a significant reduction in power generation that has had a material adverse impact on the projects ability to generate cash flow for investors. These energy curtailments are expected to persist, unless and until system upgrades are implemented to alleviate the present transmission system congestion, or the disputes are determined in favor of, or settled in a manner favorable to, Tenaska Clear Creek Wind, LLC. As such, during the fourth quarter of 2022, due to these on-going disputes, cost allocation uncertainties, and no probable favorable resolution, BCE determined its equity method investment was fully impaired. Prior to the impairment, the investment had a carrying value of $17.1 million, which has been written-down to reflect the investment s estimated fair value of zero as of December 31, 2022. Pinnacle West s Consolidated Statement of Income for the year ended December 31, 2022 includes an after-tax loss of $12.8 million relating to this impairment. BCE has started construction on a microgrid facility in Los Alamitos, California (Los Alamitos) featuring 31 MW of solar, 20 MW of battery storage, and 3 MW of backup generators. Supported by a long-term PPA with San Diego Gas and Electric Company, Los Alamitos will supply 20 MW of solar and battery storage capacity to the Southern California grid and provide resilient backup power in the event of a grid emergency to the Army and California National Guard at Joint Forces Training Base Los Alamitos. The Los Alamitos project is scheduled to achieve commercial operation in third-quarter 2023. See Note 6 regarding a credit agreement entered into by BCE to finance capital expenditures and related costs for this microgrid project. BCE and Ameresco, Inc. jointly own a special purpose entity that is sponsoring the Kpono Solar project. This project is a 42 MW solar and battery storage facility in Oahu, Hawaii that will supply clean renewable energy and capacity under a 20-year PPA with Hawaiian Electric Company, Inc. The Kpono Solar project is expected to be completed in 2024. Table of Contents El Dorado El Dorado is a wholly-owned subsidiary of Pinnacle West. El Dorado owns debt investments and minority interests in several energy-related investments and Arizona community-based ventures. El Dorado is actively seeking to prudently realize the value of these investments. In particular, El Dorado committed to a $25 million investment in the Energy Impact Partners fund, which is an organization that focuses on fostering innovation and supporting the transformation of the utility industry. The investment will be made by El Dorado as investments are selected by the Energy Impact Partners fund. As of December 31, 2022, El Dorado has contributed approximately $12.5 million to the Energy Impact Partners fund. Additionally, El Dorado committed to a $25 million investment in AZ-VC (formerly invisionAZ Fund), which is a fund focused on analyzing, investing, managing, and otherwise dealing with investments in privately-held early stage and emerging growth technology companies and businesses primarily based in the State of Arizona, or based in other jurisdictions and having existing or potential strategic or economic ties to companies or other interests in the State of Arizona. As of December 31, 2022, El Dorado has contributed approximately $2.6 million to the AZ-VC. The remainder of the investments will be contributed by El Dorado as investments are selected by the AZ-VC. Pinnacle West, APS and El Dorado are all incorporated in the State of Arizona. BCE and 4CA are incorporated in Delaware. Additional information for each of these companies is provided below: ##TABLE_START Principal Executive Office Address Year of Incorporation Approximate Number of Employees at December 31, 2022 Pinnacle West 400 North Fifth Street Phoenix, AZ 85004 1985 82 APS 400 North Fifth Street P.O. Box 53999 Phoenix, AZ 85072-3999 1920 5,772 BCE 400 East Van Buren Street Phoenix, AZ 85004 2014 7 El Dorado 400 East Van Buren Street Phoenix, AZ 85004 1983 4CA 400 East Van Buren Street Phoenix, AZ 85004 2016 Total 5,861 ##TABLE_END The APS number includes employees at jointly-owned generating facilities (approximately 2,059 employees) for which APS serves as the generating facility manager. Approximately 1,162 APS employees are union employees, represented by the International Brotherhood of Electrical Workers (IBEW). In March 2020, the Company concluded negotiations with the IBEW and approved a three-year extension of the contract set to expire on April 1, 2020. Under the extension, union members received wage increases for 2020, 2021 and 2022; there were no other changes. The current contract expires on April 1, 2023, and APS and the IBEW are currently engaged in negotiations to renew the contract. Table of Contents WHERE TO FIND MORE INFORMATION We use our website (www.pinnaclewest.com) as a channel of distribution for material Company information. The following filings are available free of charge on our website as soon as reasonably practicable after they are electronically filed with, or furnished to, the Securities and Exchange Commission (SEC): Annual Reports on Form 10-K, definitive proxy statements for our annual shareholder meetings, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and all amendments to those reports. The SEC maintains a website that contains reports, proxy and information statements and other information regarding issuers, such as the Company, that file electronically with the SEC. The address of that website is www.sec.gov. Our board and committee charters, Code of Ethics for Financial Executives, Code of Ethics and Business Practices, and other corporate governance information is also available on the Pinnacle West website. Pinnacle West will post any amendments to the Code of Ethics for Financial Executives and Code of Ethics and Business Practices, and any waivers that are required to be disclosed by the rules of either the SEC or the New York Stock Exchange on its website. The information on Pinnacle Wests website is not incorporated by reference into this report. You can request a copy of these documents, excluding exhibits, by contacting Pinnacle West at the following address: Pinnacle West Capital Corporation, Office of the Corporate Secretary, Mail Station 8602, P.O. Box 53999, Phoenix, Arizona 85072-3999 (telephone 602-250-3011). ITEM 1A. RISK FACTORS In addition to the factors affecting specific business operations identified in the description of these operations contained elsewhere in this report, set forth below are risks and uncertainties that could affect our financial results. Unless otherwise indicated or the context otherwise requires, the following risks and uncertainties apply to Pinnacle West and its subsidiaries, including APS. REGULATORY RISKS Our financial condition depends upon APSs ability to recover costs in a timely manner from customers through regulated rates and otherwise execute its business strategy. APS is subject to comprehensive regulation by several federal, state and local regulatory agencies that significantly influence its business, liquidity and results of operations and its ability to fully recover costs from utility customers in a timely manner. The ACC regulates APSs retail electric rates and FERC regulates rates for wholesale power sales and transmission services. The profitability of APS is affected by the rates it may charge and the timeliness of recovering costs incurred through its rates and adjustor recovery mechanisms. Consequently, our financial condition and results of operations are dependent upon the satisfactory resolution of any APS rate proceedings, adjustor recovery and ancillary matters which may come before the ACC and FERC, including in some cases how court challenges to these regulatory decisions are resolved. Arizona, like certain other states, has a statute that allows the ACC to reopen prior decisions and modify otherwise final orders under certain circumstances. Additionally, given that APS is subject to oversight by several regulatory agencies, a resolution by one may not foreclose potential actions by others for similar or related matters. See Note 10. The ACC must also approve APSs issuance of equity and debt securities and any significant transfer or encumbrance of APS property used to provide retail electric service and must approve or receive prior notification of certain transactions between us, APS, and our respective affiliates, including the infusion of equity into APS. Decisions made by the ACC or FERC could have a material adverse impact on our financial condition, results of operations, or cash flows. Table of Contents APSs ability to conduct its business operations and avoid negative operational and financial impacts depends in part upon compliance with federal, state and local laws, judicial decisions, statutes, regulations and ACC requirements, which may be revised from time to time by legislative or other action, and obtaining and maintaining certain regulatory permits, approvals, and certificates. APS must comply in good faith with all applicable statutes, regulations, rules, tariffs, and orders of agencies that regulate APSs business, including FERC, NRC, EPA, the ACC, and state and local governmental agencies. These agencies regulate many aspects of APSs utility operations, including safety and performance, emissions, siting and construction of facilities, customer service and the rates that APS can charge retail and wholesale customers. Failure to comply can subject APS to, among other things, fines and penalties. For example, under the Energy Policy Act of 2005, FERC can impose penalties (approximately $1.2 million per day per violation) for failure to comply with mandatory electric reliability standards. APS is also required to have numerous permits, approvals and certificates from these agencies. APS believes the necessary permits, approvals and certificates have been obtained for its existing operations and that APSs business is conducted in accordance with applicable laws in all material respects. Changes in laws or regulations that govern APS, new interpretations of law and regulations, or the imposition of new or revised laws or regulations could have an adverse impact on the manner in which we operate our business and our results of operations. In particular, new or revised laws or interpretations of existing laws or regulations may impact or call into question the ACCs permissive regulatory authority, which may result in uncertainty as to jurisdictional authority within our state, and uncertainty as to whether ACC decisions will be binding or challenged by other agencies or bodies asserting jurisdiction. In November 2021, the Arizona Court of Appeals issued an opinion that called into question the ACC-approved limitation of liability provision found in the APS Service Schedules. APS sought review of the decision at the Arizona Supreme Court, which was denied; however, the Supreme Court depublished portions of the Court of Appeals decision. APS is seeking revised tariff language to mitigate potential adverse impacts on APSs future, potential litigation exposure which may result from this court decision. We are unable to predict the impact on our business and operating results from any pending or future regulatory or legislative rulemaking. The operation of APSs nuclear power plant exposes it to substantial regulatory oversight and potentially significant liabilities and capital expenditures. The NRC has broad authority under federal law to impose safety-related, security-related and other licensing requirements for the operation of nuclear generating facilities. Events at nuclear facilities of other operators or impacting the industry generally may lead the NRC to impose additional requirements and regulations on all nuclear generating facilities, including Palo Verde. In the event of noncompliance with its requirements, the NRC has the authority to impose a progressively increased inspection regime that could ultimately result in the shut-down of a unit or civil penalties, or both, depending upon the NRCs assessment of the severity of the situation, until compliance is achieved. The increased costs resulting from penalties, a heightened level of scrutiny and implementation of plans to achieve compliance with NRC requirements may adversely affect APSs financial condition, results of operations and cash flows. APS is subject to numerous environmental laws and regulations, and changes in, or liabilities under, existing or new laws or regulations may increase APSs cost of operations or impact its business plans. APS is, or may become, subject to numerous environmental laws and regulations affecting many aspects of its present and future operations, including air emissions of conventional pollutants and GHGs, water quality, discharges of wastewater and waste streams originating from fly ash and bottom ash handling facilities, solid waste, hazardous waste, and coal combustion products, which consist of bottom ash, fly ash, and air pollution control wastes. These laws and regulations can result in increased capital, Table of Contents operating, and other costs, particularly with regard to enforcement efforts focused on power plant emissions obligations. These laws and regulations generally require APS to obtain and comply with a wide variety of environmental licenses, permits, and other approvals. If there is a delay or failure to obtain any required environmental regulatory approval, or if

APS fails to obtain, maintain, or comply with any such approval, operations at affected facilities could be suspended or subject to additional expenses. In addition, failure to comply with applicable environmental laws and regulations could result in civil liability as a result of government enforcement actions or private claims or criminal penalties. Both public officials and private individuals may seek to enforce applicable environmental laws and regulations. APS cannot predict the outcome (financial or operational) of any related litigation that may arise. Environmental Clean Up. APS has been named as a PRP for a Superfund site in Phoenix, Arizona, and it could be named a PRP in the future for other environmental clean-up at sites identified by a regulatory body. APS cannot predict with certainty the amount and timing of all future expenditures related to environmental matters because of the difficulty of estimating clean-up costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all PRPs. Coal Ash. In December 2014, EPA issued final regulations governing the handling and disposal of CCR, which are generated as a result of burning coal and consist of, among other things, fly ash and bottom ash. The rule regulates CCR as a non-hazardous waste. APS currently disposes of CCR in ash ponds and dry storage areas at Cholla and Four Corners. To the extent the rule requires the closure or modification of these CCR units, modification or changes to the manner of closure of such units, or the construction of new CCR units beyond what we currently anticipate, APS would incur significant additional costs for CCR disposal. In addition, the rule may also require corrective action to address releases from CCR disposal units or the presence of CCR constituents within groundwater near CCR disposal units above certain regulatory thresholds. Ozone National Ambient Air Quality Standards. In 2015, EPA finalized revisions to the NAAQS for ozone, which set new, more stringent standards on emissions of nitrogen oxide, a precursor to ozone, in an effort to protect human health and human welfare. Depending on the final attainment designations for the new standards and the state implementation requirements, APS may be required to invest in new pollution control technologies and to generate emission offsets for new projects or facility expansions located in ozone nonattainment areas. APS cannot assure that existing environmental regulations will not be revised or that new regulations seeking to protect the environment will not be adopted or become applicable to it. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs incurred by APS are not fully recoverable from APSs customers, could have a material adverse effect on its financial condition, results of operations, or cash flows. Due to current or potential future regulations or legislation coupled with trends in natural gas and coal prices, or other clean energy rules or initiatives, the economics or feasibility of continuing to own certain resources, particularly coal facilities, may deteriorate, warranting early retirement of those plants, which may result in asset impairments. APS would seek recovery in rates for the book value of any remaining investments in the plants as well as other costs related to early retirement but cannot predict whether it would obtain such recovery. APS faces potential financial risks resulting from climate change litigation and legislative and regulatory efforts to limit GHG emissions, as well as physical and operational risks related to climate effects. Concern over climate change has led to significant legislative and regulatory efforts to limit CO_2 , which is a major byproduct of the combustion of fossil fuel, and other GHG emissions. Table of Contents Potential Financial Risks Greenhouse Gas Regulation, the Clean Power Plan and Potential Litigation. In 2015, EPA finalized a rule to limit CO_2 emissions from existing power plants, the Clean Power Plan, or CPP. The implementation of this rule within the jurisdictions where APS operates would have resulted in a shift in generation from coal to more natural gas and renewable generation. Because of a view that the federal Clean Air Act did not permit such an expansive use of administrative authority over utility generation resources, in 2019 regulations were issued that repealed the CPP and replaced it with a far narrower set of regulations focused solely on coal-fired power plant efficiency improvements. On January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE regulations and remanded them back to EPA to develop new regulations governing carbon emissions from existing power plants consistent with the courts ruling. That decision, which endorsed an expansive view of the federal Clean Air Act consistent with the CPP, was subsequently reversed by the U.S. Supreme Court on June 30, 2022. While the current administration has expressed its intent to develop new carbon emission regulations governing existing power plants in 2023, such action will be constrained by the U.S. Supreme Courts decision that the CPP violated the Clean Air Act. Depending on the outcome of future carbon emission rulemakings under the Clean Air Act targeting new and existing power plants, the utility industry may become subject to more stringent and expansive regulations. Depending on the means of compliance with federal emission performance standards, the electric utility industry may be forced to incur substantial costs necessary to achieve compliance. In addition, we anticipate that such regulations will be challenged in federal court prior to their implementation. Depending on the outcome of such judicial review, the utility industry may face alternative efforts from private parties seeking to establish alternative GHG emission limitations from power plants. Alternative GHG emission limitations may arise from litigation under either federal or state common laws or citizen suit provisions of federal environmental statutes that attempt to force federal agency rulemaking or imposing direct facility emission limitations. Such lawsuits may also seek damages from harm alleged to have resulted from power plant GHG emissions. Physical and Operational Risks. Weather extremes such as drought and high temperature variations are common occurrences in the southwest United States desert area, and these are risks that APS considers in the normal course of business in the engineering and construction of its electric system. Large increases in ambient temperatures could require evaluation of certain materials used within its system and may represent a greater challenge. Limitations on water supplies necessary to operate electric generation infrastructure could arise from prolonged drought and shortage declarations associated with key surface water resources. As part of conducting its business, APS recognizes that the southwestern United States is particularly susceptible to the risks posed by climate change, which over time is projected to exacerbate high temperature extremes and prolong drought in the area where APS conducts its business. Co-owners of our jointly owned generation and transmission facilities may have unaligned goals and positions due to the effects of legislation, regulations, economic conditions, or changes in our industry, which could have a significant impact on our ability to continue operations of such facilities. APS owns certain of its power plants and transmission facilities jointly with other owners, with varying ownership interests in such facilities. Changes in the nature of our industry and the economic viability of certain plants and facilities, including impacts resulting from types and availability of other resources, fuel costs, legislation, and regulation, together with timing considerations related to expiration of leases or other agreements for such facilities, could result in unaligned positions among co-owners. Differences in the co-owners willingness or ability to continue their participation could lead to eventual shut down of units or facilities and uncertainty related to the resulting cost recovery of such assets. See Note 3 for a discussion of the Navajo Plant and Cholla retirement and the related risks associated with APSs continued recovery of its remaining investment in the plant. Table of Contents Deregulation or restructuring of the electric industry may result in increased competition, which could have a significant adverse impact on APSs business and its results of operations. In 1999, the ACC approved rules for the introduction of retail electric competition in Arizona. Retail competition could have a significant adverse financial impact on APS due to an impairment of assets, a loss of retail customers, lower profit margins or increased costs of capital. Although some very limited retail competition existed in APSs service area in 1999 and 2000, there are currently no active retail competitors offering unbundled energy or other utility services to APSs customers. This is in large part due to a 2004 Arizona Court of Appeals decision that found critical components of the ACCs rules to be violative of the Arizona Constitution. The ruling also voided the operating authority of all the competitive providers previously authorized by the ACC. On May 9, 2013, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. The ACC subsequently opened a docket for this matter and received comments from a number of interested parties on the considerations involved in establishing retail electric deregulation in the state. One of these considerations is whether various aspects of a deregulated market, including setting utility rates on a market basis, would be consistent with the requirements of the Arizona Constitution. On September 11, 2013, after receiving legal advice from the ACC staff, the ACC voted 4-1 to close the current docket and await full Arizona Constitutional authority before any further examination of this matter. In November 2018, the ACC voted to re-examine the facilitation of a deregulated retail electric market in Arizona. On July 1 and July 2, 2019, ACC Staff issued a report and initial proposed draft rules regarding possible modifications to the ACCs retail electric competition rules. On February 10, 2020, two ACC Commissioners filed two sets of draft proposed retail electric competition rules. On February 12, 2020, ACC Staff issued its second report regarding possible modifications to the ACCs retail electric competition rules. During a

July 15, 2020, ACC Staff meeting, the ACC Commissioners discussed the possible development of a retail competition pilot program, but no action was taken. The ACC continues to discuss matters related to retail electric competition, including the potential for additional buy-through programs or other pilot programs. In April 2022, the Arizona Legislature passed and the Governor signed a bill that repealed the electric deregulation law that had been in place in Arizona since 1998. OPERATIONAL RISKS APSs results of operations can be adversely affected by various factors impacting demand for electricity. Weather Conditions. Weather conditions directly influence the demand for electricity and affect the price of energy commodities. Electric power demand is generally a seasonal business. In Arizona, demand for power peaks during the hot summer months, with market prices also peaking at that time. As a result, APSs overall operating results fluctuate substantially on a seasonal basis. In addition, APS has historically sold less power, and consequently earned less income, when weather conditions are milder. As a result, unusually mild weather could diminish APSs financial condition, results of operations, or cash flows. Apart from the impact upon electricity demand, weather conditions related to prolonged high temperatures or extreme heat events present operational challenges. In the southwestern United States, where APS conducts its business, the effects of climate change are projected to increase the overall average temperature, lead to more extreme temperature events, and exacerbate prolonged drought conditions leading to the declining availability of water resources. Extreme heat events and rising temperatures are projected to reduce the generation capacity of thermal-power plants and decrease the efficiency of the transmission grid. These operational risks related to rising temperatures and extreme heat events could affect APSs financial condition, results of operations, or cash flows. Table of Contents Higher temperatures may decrease the snowpack, which might result in lowered soil moisture and an increased threat of forest fires. Forest fires could threaten APSs communities and electric transmission lines and facilities. Any damage caused as a result of forest fires could negatively impact APSs financial condition, results of operations, or cash flows. In addition, the decrease in snowpack can also lead to reduced water supplies in the areas where APS relies upon non-renewable water resources to supply cooling and process water for electricity generation. Prolonged and extreme drought conditions can also affect APSs long-term ability to access the water resources necessary for thermal electricity generation operations. Reductions in the availability of water for power plant cooling could negatively impact APSs financial condition, results of operations, or cash flows. Effects of Energy Conservation Measures and Distributed Energy Resources. APS customers in energy efficiency and conservation programs and other demand-side management efforts, which in turn impact the demand for electricity. APS must also meet certain distributed renewable energy requirements. A portion of APSs total renewable energy requirement must be met with an increasing percentage of distributed renewable energy resources (generally, small scale renewable technologies located on customers properties). The distributed renewable energy requirement is 30% of the applicable RES requirement for

2012 and subsequent years (this requirement has been waived by the ACC for 2023). Customer participation in distributed renewable energy programs would result in lower demand since customers would be meeting some of their own energy needs. In addition to these rules and requirements, energy efficiency technologies and distributed energy resources continue to evolve, which may have similar impacts on demand for electricity. Reduced demand due to these energy efficiency requirements, distributed energy requirements and other emerging technologies, unless substantially offset through ratemaking mechanisms, could have a material adverse impact on APSs financial condition, results of operations and cash flows. Actual and Projected Customer and Sales Growth. Retail customers in APSs service territory increased 2.1% for the year ended December 31, 2022, compared with the prior-year period. For the three years through 2022, APSs customer growth averaged 2.2% per year. We currently project annual customer growth to be 1.5% to 2.5% for 2023 and the average annual growth to be in the range of 1.5% to 2.5% through 2025 based on anticipated steady population growth in Arizona during that period. Retail electricity sales in kWh, adjusted to exclude the effects of weather variations, increased 2.4% for the year ended December 31, 2022, compared with the prior-year period. While steady customer growth was offset by energy savings driven by customer conservation, energy efficiency, and distributed renewable generation initiatives, the main drivers of positive sales for this period were a strong improvement in sales to commercial and industrial customers and the ramp-up of new data center customers. For the three years through 2022, annual retail electricity sales growth averaged 2.5%, adjusted to exclude the effects of weather variations. Due to the expected rapid growth of several large data centers and new large manufacturing facilities, we currently project that annual retail electricity sales in kWh will increase in the range of 3.5% to 5.5% for 2023 and that average annual growth will be in the range of 4.5% to 6.5% through 2025, including the effects of customer conservation, energy efficiency, and distributed renewable generation initiatives, but excluding the effects of weather variations. This projected sales growth range includes the impacts of several large data centers and new large manufacturing facilities, which are expected to contribute to average annual growth in the range of 3.5% to 5.5% through 2025. Actual sales growth, excluding weather-related variations, may differ from our projections as a result of numerous factors, such as economic conditions, customer growth, usage patterns and energy conservation, slower ramp-up of and/or fewer data centers and large manufacturing facilities, slower than expected commercial and industrial expansions, impacts of energy efficiency programs, and growth in DG, Table of Contents and responses to retail price changes. Based on past experience, a 1% variation in our annual residential and small commercial and industrial kWh sales projections under normal business conditions can result in increases or decreases in annual net income of approximately $20 million, and a 1% variation in our annual large commercial and industrial kWh sales projections under normal business conditions can result in increases or decreases in annual net income of approximately $5 million. The operation of power generation facilities and transmission systems involves risks that could result in reduced output or unscheduled outages, which could materially affect APSs results of operations . The operation of power generation, transmission and distribution facilities involves certain risks, including the risk of breakdown or failure of equipment, fuel interruption, and performance below expected levels of output or efficiency. Unscheduled outages, including extensions of scheduled outages due to mechanical failures or other complications, occur from time to time and are an inherent risk of APSs business. Because our transmission facilities are interconnected with those of third parties, the operation of our facilities could be adversely affected by unexpected or uncontrollable events occurring on the larger transmission power grid, and the operation or failure of our facilities could adversely affect the operations of others. Concerns over physical security of these assets could include damage to certain of our facilities due to vandalism or other deliberate acts that could lead to outages or other adverse effects. If APSs facilities operate below expectations, especially during its peak seasons, it may lose revenue or incur additional expenses, including increased purchased power expenses. The impact of wildfires could negatively affect APSs results of operations. Wildfires have the potential to affect the communities that APS serves and APSs vast network of electric transmission and distribution lines and facilities. The potential likelihood of wildfires has increased due to many of the same weather and climate change impacts existing in Arizona as those that led to the catastrophic wildfires in California. While we proactively take steps to mitigate wildfire risk in the areas of our electrical assets, wildfire risk is always present due to APSs expansive service territory. APS could be held liable for damages incurred as a result of wildfires if it was determined that they were caused by or enhanced due to APSs negligence. Any damage caused to our assets, loss of service to our customers, or liability imposed as a result of wildfires could negatively impact APSs financial condition, results of operations, or cash flows. The inability to successfully develop, acquire or operate generation resources to meet future resource needs and load forecasts in accordance with reliability requirements and other new or evolving standards and regulations could adversely impact our business. Potential changes in regulatory standards, impacts of new and existing laws and regulations, including environmental laws and regulations, and the need to obtain various regulatory approvals create uncertainty surrounding our current and future generation portfolio. The current regulatory standards, laws, and regulations create strategic challenges as to the appropriate generation portfolio and fuel diversification mix. In addition, APS is required by the ACC to meet certain energy resource portfolio requirements, including those related to renewables development and energy efficiency measures, in addition to specific competitive resource procurement requirements. The development and operation of any generation facility is also subject to many risks, including those related to financing, siting, permitting, new and evolving technology, and the construction of sufficient transmission capacity to support these facilities. APS needs to develop or acquire new generation facilities, potentially modernize existing facilities, and/or contract for additional capacity in order to meet future resource needs and load forecasts. APSs inability to do so could have a material adverse impact on our business and results of operations. In expressing concerns about the environmental and climate-related impacts from continued extraction, transportation, delivery and combustion of fossil fuels, environmental advocacy groups and other third parties have in recent years undertaken greater efforts to oppose the permitting, construction, Table of Contents and operation of fossil fuel infrastructure projects. These efforts may increase in scope and frequency depending on a number of variables, including the future course of Federal environmental regulation and the increasing financial resources devoted to these opposition activities. APS cannot predict the effect that any such opposition may have on our ability to develop, construct, and operate fossil fuel infrastructure projects in the future. In January 2020, APS announced its goal to provide 100% clean, carbon-free electricity by 2050 with an intermediate 2030 target of achieving a resource mix that is 65% clean energy, with 45% of the generation portfolio coming from renewable energy. APSs ability to successfully execute its clean energy commitment is dependent upon a number of external factors, some of which include supportive national and state energy policies, a supportive regulatory environment, sales and customer growth, the development, deployment and advancement of clean energy technologies, adequate supply chain for generation resources, and continued access to capital markets. The lack of access to sufficient supplies of water could have a material adverse impact on APSs business and results of operations. Assured supplies of water are important for APSs generating plants. Water in the southwestern United States is limited, and various parties have made conflicting claims regarding the right to access and use such limited supply of water. Both groundwater and surface water in areas important to the operation of APSs generating plants have been and are the subject of inquiries, claims and legal proceedings. In addition, the region in which APSs power plants are located suffer from prolonged drought conditions, which could potentially affect the plants water supplies. Climate change is also projected to exacerbate such drought conditions. In addition, Colorado River water supplies for Arizona are subject to a Tier 2a shortage declaration, which substantially limits the quantity of water available for the state. APSs inability to access sufficient supplies of water, along with that of its customers, could have a material adverse impact on our business and results of operations. We are subject to cybersecurity risks and risks of unauthorized access to our systems that could adversely affect our business and financial condition. We operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. In the regular course of our business, we handle a range of sensitive security, customer, and business systems information. There appears to be an increasing level of activity, sophistication, and maturity of threat actors, including from both nation state and non-nation state actors, that seek to exploit potential vulnerabilities in the electric utility industry and wish to disrupt the U.S. bulk power system, our information technology systems, generation (including our Palo Verde nuclear facility), transmission and distribution facilities, and other infrastructure facilities and systems and physical assets. We have been and could be the target of attacks, and the aforementioned systems are critical areas of cyber protection for us. We rely extensively on IT systems, networks, and services, including internet sites, data hosting and processing facilities, and other hardware, software and technical applications and platforms. Some of these systems are managed, hosted, provided, or used for third parties to assist in conducting our business. Malicious actors may attack vendors to disrupt the services these vendors provide to us or to use those vendors as a cyber conduit to attack us. As more third parties are involved in the operation of our business, there is a risk the confidentiality, integrity, privacy, or security of data held by, or accessible to, third parties may be compromised. If a significant cybersecurity event or breach were to occur, we may not be able to fulfill critical business functions and we could (i) experience property damage, disruptions to our business, theft of or unauthorized access to customer, employee, financial or system operation information or other information; (ii) experience loss of revenue or incur significant costs for repair, remediation and breach Table of Contents notification, and increased capital and operating costs to implement increased security measures; and (iii) be subject to increased regulation, litigation and reputational damage. If such disruptions or breaches are not detected quickly, their effects could be compounded or could delay our response or the effectiveness of our response and ability to limit our exposure to potential liability. These types of events would also require significant management attention and resources and could have a material adverse impact on our financial condition, results of operations, or cash flows. We develop and maintain systems and processes aimed at detecting and preventing information and cybersecurity incidents which require significant investment, maintenance, and ongoing monitoring and updating as technologies and regulatory requirements change. These systems and processes may be insufficient to mitigate the possibility of cybersecurity incidents, malicious social engineering, fraudulent or other malicious activities, and human error or malfeasance in the safeguarding of our data. We are subject to laws and rules issued by multiple government agencies concerning safeguarding and maintaining the confidentiality of our security, customer information and business information. One of these agencies, NERC, has issued comprehensive regulations and standards surrounding the security of bulk power systems, and is continually in the process of developing updated and additional requirements with which the utility industry must comply. The NRC also has issued regulations and standards related to the protection of critical digital assets at commercial nuclear power plants. The increasing promulgation of NERC and NRC rules and standards will increase our compliance costs and our exposure to the potential risk of violations of the standards. Experiencing a cybersecurity incident could cause us to be non-compliant with applicable laws and regulations, such as those promulgated by NERC and the NRC, privacy laws, or contracts that require us to securely maintain confidential data, causing us to incur costs related to legal claims or proceedings and regulatory fines or penalties. The risk of these system-related events and security breaches occurring continues to intensify. We have experienced, and expect to continue to experience, threats and attempted intrusions to our information technology systems and we could experience such threats and attempted intrusions to our operational control systems. To date, we do not believe we have experienced a material breach or disruption to our network or information systems or our service operations. We may not be able to anticipate and prevent all cyberattacks or information security breaches, and our ongoing investments in security resources, talent, and business practices may not be effective against all threat actors. We maintain cyber insurance to provide coverage for a portion of the losses and damages that may result from a security breach of our information technology systems, but such insurance is subject to a number of exclusions and may not cover the total loss or damage caused by a breach. Coverage for cybersecurity events continues to evolve as the industry matures. In the future, adequate insurance may not be available at rates that we believe are reasonable, and the costs of responding to and recovering from a cyber incident may not be covered by insurance or recoverable in rates. The ownership and operation of power generation and transmission facilities on Indian lands could result in uncertainty related to continued leases, easements, and rights-of-way, which could have a significant impact on our business. Four Corners and portions of certain APS transmission lines are located on Indian lands pursuant to leases, easements or other rights-of-way that are effective for specified periods. APS is unable to predict the final outcomes of pending and future approvals by the applicable sovereign governing bodies with respect to renewals of these leases, easements, and rights-of-way. Table of Contents There are inherent risks in the ownership and operation of nuclear facilities, such as environmental, health, fuel supply, spent fuel disposal, regulatory and financial risks and the risk of terrorist attack that could adversely affect our business and financial condition. APS has an ownership interest in and operates on behalf of a group of participants, Palo Verde, which is the largest nuclear electric generating facility in the United States. Palo Verde constitutes approximately 18% of APSs owned and leased generation capacity. Palo Verde is subject to environmental, health and financial risks, such as the ability to obtain adequate supplies of nuclear fuel; the ability to dispose of spent nuclear fuel; the ability to maintain adequate reserves for decommissioning; potential liabilities arising out of the operation of these facilities; the costs of securing the facilities against possible terrorist attacks; and unscheduled outages due to equipment and other problems. APS maintains nuclear decommissioning trust funds and external insurance coverage to minimize its financial exposure to some of these risks; however, it is possible that damages could exceed the amount of insurance coverage. APS may be required under federal law to pay up to $120.1 million (but not more than $17.9 million per year) of liabilities arising out of a nuclear incident not only at Palo Verde, but at any other nuclear power plant in the United States. In addition, APS is subject to retrospective premium adjustments under its nuclear property insurance policies with Nuclear Electric Insurance Limited (NEIL) for approximately $22.3 million if NEILs losses in any policy year exceed accumulated funds and if the retrospective premium assessment is declared by NEILs Board of Directors. Although APS has no reason to anticipate a serious nuclear incident at Palo Verde, if an incident did occur, it could materially and adversely affect our results of operations and financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit and to promulgate new regulations that could require significant capital expenditures and/or increase operating costs. Changes in technology could create challenges for APSs existing business. Alternative energy technologies that produce power or reduce power consumption or emissions are being developed and commercialized, including renewable technologies such as photovoltaic (solar) cells, customer-sited generation, energy storage (batteries) and efficiency technologies. Advances in technology and equipment/appliance efficiency could reduce the demand for supply from conventional generation, including carbon-free nuclear generation, and increase the complexity of managing APSs information technology and power system operations, which could adversely affect APSs business. Customer-sited alternative energy technologies present challenges to APSs operations due to misalignment with APSs existing operational needs. When these resources lack dispatchability and other elements of utility-side control, they are considered unmanaged resources. The cumulative effect of such unmanaged resources results in added complexity for APSs system management. APS continues to pursue and implement advanced grid technologies, including transmission and distribution system technologies and digital meters enabling two-way communications between the utility and its customers. Many of the products and processes resulting from these and other alternative technologies, including energy storage technologies, have not yet been widely used or tested on a long-term basis, and their use on large-scale systems is not as established or mature as APSs existing technologies and equipment. The implementation of new and additional technologies adds complexity to our information technology and operational technology systems, which could require additional infrastructure and resources. Widespread installation and acceptance of new technologies could also enable the entry of new market participants, such as technology companies, into the interface between APS and its customers and could have other unpredictable effects on APSs traditional business model. Deployment of renewable energy technologies is expected to continue across the western states and result in a larger portion of the overall energy production coming from these sources. These trends, which Table of Contents have benefited from historical and continuing government support for certain technologies, have the potential to put downward pressure on wholesale power prices throughout the western states which could make APSs existing generating facilities less economical and impact their operational patterns and long-term viability. We are subject to employee workforce factors that could adversely affect our business and financial condition. Like many companies in the electric utility industry, our workforce is maturing, with approximately 30% of employees eligible to retire by the end of 2027. Although we have undertaken efforts to recruit, train and develop new employees, we face increased competition for talent. We are subject to other employee workforce factors, such as the availability and retention of qualified personnel and the need to negotiate collective bargaining agreements with union employees. These or other employee workforce factors could negatively impact our business, financial condition, or results of operations. COVID-19 could negatively affect our business. COVID-19 is a continually developing situation around the globe that has led to economic disruption and volatility in the financial markets. The spread of COVID-19 and efforts to contain the virus and mitigate its public health effects, could decrease demand for energy, lower economic growth, impact our employees and contractors, cause disruptions in our supply chain, increase certain costs, further increase volatility in the capital markets (and result in increases in the cost of capital or an inability to access the capital markets or draw on available credit facilities), delay the completion of capital or other construction projects and other operations and maintenance activities, delay payments or increase uncollectable accounts, impact our ability to hire or retain qualified employees, or cause other unpredictable events, each of which could adversely affect our business, results of operations, cash flows or financial condition. FINANCIAL RISKS A downgrade of our credit ratings could materially and adversely affect our business, financial condition, and results of operations. Our current ratings are set forth in Liquidity and Capital Resources Credit Ratings in Item 7. We cannot be sure that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Any downgrade or withdrawal could adversely affect the market price of Pinnacle Wests and APSs securities, limit our access to capital and increase our borrowing costs, which would adversely impact our financial results. We could be required to pay a higher interest rate for future financings, and our potential pool of investors and funding sources could decrease. In addition, borrowing costs under our existing credit facilities depend on our credit ratings. A downgrade could also require us to provide additional support in the form of letters of credit or cash or other collateral to various counterparties. If our short-term ratings were to be lowered, it could severely limit access to the commercial paper market. We note that the ratings from rating agencies are not recommendations to buy, sell or hold our securities and that each rating should be evaluated independently of any other rating. Investment performance, changing interest rates, new rules or regulations and other economic, social, and political factors could decrease the value of our benefit plan assets, nuclear decommissioning trust funds and other special use funds or increase the valuation of our related obligations, resulting in significant additional funding requirements. We are also subject to risks related to the provision of employee healthcare benefits and healthcare reform legislation. Any inability to fully recover these costs in our utility rates would negatively impact our financial condition. Table of Contents We have significant pension plan and other postretirement benefits plan obligations to our employees and retirees, and legal obligations to fund our pension trust and nuclear decommissioning trusts for Palo Verde. We hold and invest substantial assets in these trusts that are designed to provide funds to pay for certain of these obligations as they arise. Declines in market values of the fixed income and equity securities held in these trusts may increase our funding requirements into the related trusts. Additionally, the valuation of liabilities related to our pension plan and other postretirement benefit plans are impacted by a discount rate, which is the interest rate used to discount future pension and other postretirement benefit obligations. Declining interest rates decrease the discount rate, increase the valuation of the plan liabilities, and may result in increases in pension and other postretirement benefit costs, cash contributions, regulatory assets, and charges to OCI. Changes in demographics, including increased number of retirements or changes in life expectancy and changes in other actuarial assumptions, may also result in similar impacts. The minimum contributions required under these plans are impacted by federal legislation and related regulations. Increasing liabilities or otherwise increasing funding requirements under these plans, resulting from adverse changes in legislation or otherwise, could result in significant cash funding obligations that could have a material impact on our financial position, results of operations, or cash flows. We recover most of the pension and other postretirement benefit expense and all of the currently estimated nuclear decommissioning costs in our regulated rates. Any inability to fully recover these costs in a timely manner could have a material negative impact on our financial condition, results of operations, or cash flows. Pending or future federal or state legislative or regulatory activity or court proceedings could increase costs of providing medical insurance for our employees and retirees. Any potential changes and resulting cost impacts cannot be determined with certainty at this time. Our cash flow depends on the performance of APS and its ability to make distributions. We derive essentially all of our revenues and earnings from our wholly-owned subsidiary, APS. Accordingly, our cash flow and our ability to pay dividends on our common stock is dependent upon the earnings and cash flows of APS and its distributions to us. APS is a separate and distinct legal entity and has no obligation to make distributions to us. APSs financing agreements may restrict its ability to pay dividends, make distributions or otherwise transfer funds to us. In addition, an ACC financing order requires APS to maintain a common equity ratio of at least 40% and does not allow APS to pay common dividends if the payment would reduce its common equity below that threshold. The common equity ratio, as defined in the ACC order, is total shareholder equity divided by the sum of total shareholder equity and long-term debt, including current maturities of long-term debt. Pinnacle Wests ability to meet its debt service obligations could be adversely affected because its debt securities are structurally subordinated to the debt securities and other obligations of its subsidiaries. Because Pinnacle West is structured as a holding company, all existing and future debt and other liabilities of its subsidiaries will be effectively senior in right of payment to its own debt securities. The assets and cash flows of our subsidiaries will be available, in the first instance, to service their own debt and other obligations. Our ability to have the benefit of their cash flows, particularly in the case of any insolvency or financial distress affecting our subsidiaries, would arise only through our equity ownership interests in our subsidiaries and only after their creditors have been satisfied. The use of derivative contracts in the normal course of our business could result in financial losses that negatively impact our results of operations. APSs operations include managing market risks related to commodity prices. APS is exposed to the impact of market fluctuations in the price and transportation costs of electricity, natural gas, and coal to Table of Contents the extent that unhedged positions exist. We have established procedures to manage risks associated with these market fluctuations by utilizing various commodity derivatives, including exchange traded futures and over-the-counter (OTC) forwards, options, and swaps. As part of our overall risk management program, we enter into derivative transactions to hedge purchases and sales of electricity and natural gas. The changes in market value of such contracts have a high correlation to price changes in the hedged commodity. To the extent that commodity markets are illiquid, we may not be able to execute our risk management strategies, which could result in greater unhedged positions than we would prefer at a given time and financial losses that negatively impact our results of operations. The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) contains measures aimed at increasing the transparency and stability of the over-the-counter derivative markets and preventing excessive speculation. The Dodd-Frank Act could restrict, among other things, trading positions in the energy futures markets, require different collateral or settlement positions, or increase regulatory reporting over derivative positions. Based on the provisions included in the Dodd-Frank Act and the implementation of regulations, these changes could, among other things, impact our ability to hedge commodity price and interest rate risk or increase the costs associated with our hedging programs. We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We use a risk management process to assess and monitor the financial exposure of all counterparties. Despite the fact that the majority of APSs trading counterparties are rated as investment grade by the rating agencies, there is still a possibility that one or more of these companies could default, which could result in a material adverse impact on our earnings for a given period. GENERAL RISKS Proposals to change policy in Arizona or other states made through ballot initiatives or referenda may increase the Companys cost of operations or impact its business plans. In Arizona and other states, a person or organization may file a ballot initiative or referendum with the Arizona Secretary of State or other applicable state agency and, if a sufficient number of verifiable signatures are presented, the initiative or referendum may be placed on the ballot for the public to vote on the matter. Ballot initiatives and referenda may relate to any matter, including policy and regulation related to the electric industry, and may change statutes or the state constitution in ways that could impact Arizona utility customers, the Arizona economy, and the Company. Some ballot initiatives and referenda are drafted in an unclear manner and their potential industry and economic impact can be subject to varied and conflicting interpretations. We may oppose certain initiatives or referenda (including those that could result in negative impacts to our customers, the state, or the Company) via the electoral process, litigation, traditional legislative mechanisms, agency rulemaking or otherwise, which could result in significant costs to the Company. The passage of certain initiatives or referenda could result in laws and regulations that impact our business plans and have a material adverse impact on our financial condition, results of operations, or cash flows. General economic conditions could materially affect our business, financial condition, and results of operations. General economic factors that are beyond the Companys control impact the Companys forecasts and actual performance. These factors include interest rates; recession; inflation; stagflation; deflation; supply chain constraints; unemployment trends; sanctions, trade restrictions, military interventions and the threat or possibility of war; terrorism or other global or national unrest; and political or financial instability. In particular, during 2021 and 2022, the United States economy has experienced a substantial rise in the inflation rate. There is increased uncertainty as to whether the rise in inflation will continue and for how long. Increases in inflation raise the Companys costs for commodities, labor, materials and services. Additionally, COVID-19 severely impacted global supply chains, resulting in equipment delays and Table of Contents increased costs. A failure to recover the increased costs caused by increased inflation and supply chain constraints through our rates could have a material adverse impact on our financial condition, results of operations, or cash flows. The market price of our common stock may be volatile. The market price of our common stock could be subject to significant fluctuations in response to factors such as the following, some of which are beyond our control: variations in our quarterly operating results; operating results that vary from the expectations of management, securities analysts, and investors; changes in expectations as to future financial performance, including financial estimates by securities analysts and investors; developments generally affecting industries in which we operate; announcements by us or our competitors of significant contracts, acquisitions, joint marketing relationships, joint ventures, or capital commitments; announcements by third parties of significant claims or proceedings against us; favorable or adverse regulatory or legislative developments; our dividend policy; change in our management; future sales by the Company of equity or equity-linked securities; and general domestic and international economic conditions. In addition, the stock market in general has experienced volatility that has often been unrelated to the operating performance of a particular company. These broad market fluctuations may adversely affect the market price of our common stock. Financial market disruptions or new rules or regulations may increase our financing costs or limit our access to various financial markets, which may adversely affect our liquidity and our ability to implement our financial strategy. Pinnacle West and APS rely on access to credit markets as a significant source of liquidity and the capital markets for capital requirements not satisfied by cash flow from our operations. We believe that we will maintain sufficient access to these financial markets. However, certain market disruptions or revisions to rules or regulations may cause our cost of borrowing to increase generally, and/or otherwise adversely affect our ability to access these financial markets. In addition, the credit commitments of our lenders under our bank facilities may not be satisfied or continued beyond current commitment periods for a variety of reasons, including new rules and regulations, changes to the internal policies of our lenders, periods of financial distress or liquidity issues affecting our lenders or financial markets, which could materially adversely affect the adequacy of our liquidity sources and/or the cost of maintaining these sources. Changes in economic conditions, monetary policy, fiscal policy, financial regulation, rating agency treatment and/or other factors could result in higher interest rates, which would increase interest expense on our existing variable rate debt and new debt we expect to issue in the future, and thus increase the cost and/or reduce the amount of funds available to us for our current plans. Table of Contents Additionally, an increase in our leverage, whether as a result of these factors or otherwise, could adversely affect us by: causing a downgrade of our credit ratings; increasing the cost of future debt financing and refinancing; increasing our vulnerability to adverse economic and industry conditions; and requiring us to dedicate an increased portion of our cash flow from operations to payments on our debt, which would reduce funds available to us for operations, future investment in our business or other purposes. Certain provisions of our articles of incorporation and bylaws and of Arizona law make it difficult for shareholders to change the composition of our board and may discourage takeover attempts. These provisions, which could preclude our shareholders from receiving a change of control premium, include the following: restrictions on our ability to engage in a wide range of business combination transactions with an interested shareholder (generally, any person who beneficially owns 10% or more of our outstanding voting power, or any of our affiliates or associates who beneficially owned 10% or more of our outstanding voting power at any time during the prior three years) or any affiliate or associate of an interested shareholder, unless specific conditions are met; anti-greenmail provisions of Arizona law and our bylaws that prohibit us from purchasing shares of our voting stock from beneficial owners of more than 5% of our outstanding shares unless specified conditions are satisfied; the ability of the Board of Directors to increase the size of and fill vacancies on the Board of Directors, whether resulting from such increase, or from death, resignation, disqualification or otherwise; the ability of our Board of Directors to issue additional shares of common stock and shares of preferred stock and to determine the price and, with respect to preferred stock, the other terms, including preferences and voting rights, of those shares without shareholder approval; restrictions that limit the rights of our shareholders to call a special meeting of shareholders; and restrictions regarding the rights of our shareholders to nominate directors or to submit proposals to be considered at shareholder meetings. While these provisions may have the effect of encouraging persons seeking to acquire control of us to negotiate with our Board of Directors, they could enable the Board of Directors to hinder or frustrate a transaction that some, or a majority, of our shareholders might believe to be in their best interests and, in that case, may prevent or discourage attempts to remove and replace incumbent directors.

Ticker: POR, Sector: Utilities, Filed At: 2023-02-15T19:18:09-05:00

ITEM 1. BUSINESS. General Portland General Electric Company (PGE or the Company), a vertically-integrated electric utility with corporate headquarters located in Portland, Oregon, is engaged in the generation, wholesale purchase, transmission, distribution, and retail sale of electricity in the state of Oregon (State). The Company operates as a cost-based, regulated electric utility with revenue requirements and customer prices determined based on the forecasted cost to serve retail customers and a reasonable rate of return as determined by the Public Utility Commission of Oregon (OPUC). PGE meets its retail load requirement with both Company-owned generation and power purchased in the wholesale market. The Company participates in the wholesale market through the purchase and sale of electricity and natural gas in an effort to obtain reasonably-priced power to serve its retail customers. PGE is committed to developing products and service offerings for the benefit of retail and wholesale customers. PGE, incorporated in 1930, is publicly-owned, with its common stock listed on the New York Stock Exchange (NYSE). The Company operates as a single business segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis. The Company owns unregulated, non-utility real estate comprised primarily of PGEs corporate headquarters. PGEs State-approved service area allocation of four thousand square miles is located entirely within Oregon and includes 51 incorporated cities. During 2022, the Company added nine thousand customers, and as of December 31, 2022, served a total of 926 thousand retail customers. Available Information PGEs periodic and current reports, and amendments to those reports, are available and may be accessed free of charge through the Investors section of the Companys website at PortlandGeneral.com as soon as reasonably practicable after the reports are electronically filed with, or furnished to, the United States Securities and Exchange Commission (SEC). It is not intended that PGEs website and the information contained therein or connected thereto be incorporated into this Annual Report on Form 10-K. Regulation Federal and State regulation each have a significant influence on PGEs business operations. In addition to the agencies and activities discussed below, the Company is subject to regulation by certain environmental agencies, as described in the Environmental Matters section in this Item 1. Federal Regulation Several federal agencies, including the Federal Energy Regulatory Commission (FERC), the U.S. Department of Transportations Pipeline and Hazardous Materials Safety Administration (PHMSA), and the Nuclear Regulatory Commission (NRC), have regulatory authority over certain of PGEs operations and activities, as described in the discussion that follows. PGE is a licensee, a public utility, and a user, owner, and operator of the bulk power system, as those terms are defined in the Federal Power Act (FPA). As such, the Company is subject to regulation by the FERC in matters related to wholesale energy activities, transmission services, reliability and cybersecurity standards, natural gas pipelines, hydroelectric projects, accounting policies and practices, short-term debt issuances, and certain other matters. Wholesale Energy PGE has authority under its FERC Market-Based Rates tariff to charge market-based rates for wholesale energy sales in all markets in which it sells electricity except in its own Balancing Authority Area (BAA). The BAA is the area in which PGE is responsible for balancing customer demand with electricity supply, in real time, and the tariff exception within PGEs BAA does not have a material impact on the Company. Transmission PGE offers wholesale electricity transmission service pursuant to its Open Access Transmission Tariff (OATT), which contains rates, terms, and conditions of service, as filed with, and approved by, the FERC. Reliability and Cybersecurity Standards The FERC has adopted mandatory reliability standards for owners, users, and operators of the bulk power system. Such standards, which are applicable to PGE, were developed by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC), which have responsibility for compliance and enforcement of these standards, and are intended to help protect critical cyber and physical assets used to support reliable operations. Natural Gas Pipelines The FERC has authority in matters related to the construction, operation, extension, enlargement, safety, and abandonment of jurisdictional interstate natural gas pipeline facilities, as well as transportation rates and accounting for interstate natural gas commerce. PGE is subject to such authority as the Company has a 79.5% ownership interest in the Kelso-Beaver (KB) Pipeline, a 17-mile, 20-inch diameter, interstate pipeline that provides natural gas to

Port Westward Unit 1 (PW1), Port Westward Unit 2 (PW2), and Beaver, the Companys natural gas-fired generating plants located near Clatskanie, Oregon, to the North Mist storage facility (owned and operated by a local natural gas distribution company), and to one additional local delivery point that serves a manufacturing concern. As the operator of record of the KB Pipeline, PGE is subject to the requirements and regulations enacted under the Pipeline Safety Laws administered by the PHMSA, which include safety and operator qualification standards in addition to public awareness requirements. Hydroelectric Licensing As required under the FPA, PGE holds FERC licenses for all Company-owned and operated hydroelectric generating plants. The FERC license process includes an extensive public review process that involves the consideration of numerous natural resource issues and environmental conditions. For additional information, see the Environmental Matters section in this Item 1. and the Generating Facilities section in Item 2.Properties. Accounting Policies and Practices PGE prepares periodic and current reports in accordance with accounting principles generally accepted in the United States of America (GAAP). In addition, the Company prepares, pursuant to applicable provisions of the FPA, financial statements in accordance with the accounting requirements of the FERC, as set forth in its applicable Uniform System of Accounts and published accounting releases. Such financial statements are included in annual and quarterly reports filed with the FERC. Short-term Debt Pursuant to applicable provisions of the FPA and FERC regulations, regulated public utilities are required to obtain FERC approval to issue certain securities. For additional information on the Companys Short-term Debt, see Short-term Debt in the Debt and Equity section of Liquidity and Capital Resources in Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Spent Fuel Storage The NRC regulates the licensing and decommissioning of nuclear power plants, including PGEs decommissioned Trojan nuclear power plant (Trojan), which was closed in 1993. For additional information on spent nuclear fuel storage activities, see Note 8, Asset Retirement Obligations in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data and Hazardous Material in the Environmental Matters section of this Item 1. State Regulation PGE is subject to the jurisdiction of the OPUC, which reviews and approves the Companys retail prices and reviews the Companys generation and transmission resource acquisition plans, pursuant to a biennial integrated resource planning process. The OPUC regulates the issuance of securities, prescribes accounting policies and practices, regulates the sale of utility assets, reviews transactions with affiliated companies, and has jurisdiction over the acquisition of, or exertion of substantial influence over, public utilities. Retail customer prices are determined through formal public proceedings that generally include testimony by participating parties, discovery, public hearings, and the issuance of a final order by the OPUC. Participants in such proceedings may include PGE, OPUC staff, and intervenors representing PGE customer groups, as well as other interested parties. The following lists the more significant regulatory mechanisms and proceedings under which customer prices are determined: General Rate Cases . PGE periodically

evaluates the need to update its retail electric price structure as part of a comprehensive general rate case process that reflects revenue requirements based on a forecasted test year. The OPUC authorizes the Companys debt-to-equity capital structure, return on equity, overall rate of return, and customer prices. Annual Power Cost Updates . The OPUC has approved an Annual Power Cost Update Tariff (AUT) by which PGE can adjust retail customer prices annually to reflect forecasted changes in the Companys net variable power costs (NVPC). NVPC consists of the cost of power purchased and fuel used to generate electricity, as well as the cost of settled electric and natural gas financial contracts (all classified as Purchased power and fuel expense in the Companys consolidated statements of income) and is net of wholesale revenues, which are classified in the consolidated statements of income as Revenues, net. The OPUC has also authorized a Power Cost Adjustment Mechanism (PCAM), under which PGE may share with customers a portion of actual cost variances associated with NVPC. Renewable Energy. The State has a Renewable Portfolio Standard (RPS) that requires PGE to serve a portion of its retail load with renewable resources. In conjunction with the RPS, the State established a Renewable Adjustment Clause (RAC) mechanism that allows for the recovery in retail customer prices, outside of a general rate case, of prudently incurred costs to comply with the RPS. In 2016, the State also passed Oregon Senate Bill (SB) 1547, a law referred to as the Oregon Clean Electricity and Coal Transition Plan, which, among its provisions, increased the RPS percentages in certain future years and required the elimination of coal from Oregon utility customers energy supply. For further information on SB 1547, see RPS standards and other laws in the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. During 2021, the State legislature passed House Bill (HB) 2021, which establishes clean energy targets and sets out a framework that includes, among other things, the development and submittal of clean energy plans for investor-owned utilities, including PGE, and electric service suppliers in the State. The targets are an 80% reduction in greenhouse gas (GHG) emissions by 2030, 90% by 2035, and 100% by 2040 and every year thereafter. For further information on HB 2021 and the baseline to which the target reductions apply, see HB 2021 in the Laws and Regulations portion of the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Regulatory Accounting PGE prepares financial statements in accordance with GAAP and, as a regulated public utility, the effects of rate regulation are reflected in its financial statements. GAAP provides for the deferral, as regulatory assets, of certain actual or estimated costs that would otherwise be charged to expense, based on expected recovery from customers in future prices. Likewise, certain actual or anticipated credits that would otherwise be recognized as revenue or reduce expense can be deferred as regulatory liabilities, based on expected future credits or refunds to customers. PGE records regulatory assets or liabilities if it is probable that they will be reflected in future prices, based on regulatory orders or other available evidence. The Company periodically assesses the applicability of regulatory accounting to its business, considering both the current and

anticipated future regulatory environment and related accounting guidance . For additional information, see Regulatory Assets and Liabilities in Note 2, Summary of Significant Accounting Policies, and Note 7, Regulatory Assets and Liabilities, in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data. Customers and Revenues PGE generates revenue primarily through the sale and delivery of electricity to retail customers located exclusively in Oregon. In addition, the Company distributes power to customers that choose to purchase their energy from an Electricity Service Supplier (ESS). Although the Company includes such Direct Access customers in its customer counts and energy delivered to such commercial and industrial customers in its total retail energy deliveries, retail revenues include only delivery charges and applicable transition adjustments for these Direct Access customers, as the customers purchase energy directly from the ESSs. The Company conducts retail electric operations within its State-approved service territory and competes with ESSs to supply certain commercial and industrial customer energy needs. In addition, PGE competes with the local natural gas distribution company for the energy needs of residential and commercial space heating, water heating, and appliances. Energy efficiency, conservation measures, and the advancement of distributed generation, including rooftop solar, and storage resources also have an influence on customer demand. Retail Revenues Retail customers are classified as residential, commercial, or industrial, with no single customer representing more than 8% of PGEs total retail revenues or 13% of total retail deliveries. PGEs Retail revenues, retail energy deliveries, and average number of retail customers consist of the following: ##TABLE_START Years Ended December 31, 2022 2021 2020 Retail revenues (1) (dollars in millions): Residential $ 1,158 52 % $ 1,118 54 % $ 1,030 53 % Commercial 735 33 708 34 634 33 Industrial 312 14 279 13 246 13 Subtotal 2,205 99 2,105 101 1,910 99 Alternative revenue programs, net of amortization 11 1 (29) (1) (6) Other accrued revenues, net (2) 7 2 28 1 Total retail revenues $ 2,223 100 % $ 2,078 100 % $ 1,932 100 % Retail energy deliveries (3) (MWh in thousands): Residential 8,088 38 % 7,978 39 % 7,756 40 % Commercial 7,198 34 7,193 35 6,855 35 Industrial 5,945 28 5,361 26 4,932 25 Total retail energy deliveries 21,231 100 % 20,532 100 % 19,543 100 % Average number of retail customers: Residential 809,573 88 % 800,372 88 % 791,119 88 % Commercial 112,602 12 111,569 12 110,851 12 Industrial 269 268 267 Total 922,444 100 % 912,209 100 % 902,237 100 % ##TABLE_END##TABLE_START ##TABLE_END(1) Includes both revenues from customers who purchase their energy supplies from the Company and revenues from the delivery of energy to those commercial and industrial customers that purchase their energy from ESSs. (2) Amount for the year ended December 31, 2020 is primarily comprised of $24 million of amortization, including interest, related to the deferral recorded in 2018 for the net tax benefits due to the change in corporate tax rate under the United States Tax Cuts and Jobs Act of 2017 (TCJA). (3) Includes both energy sold to retail customers and energy deliveries to those commercial and industrial customers that purchase their energy from ESSs. The following table presents additional annual

averages for retail customers. Certain supplemental tariff collections are excluded from revenues as they are not considered a part of the Companys base retail prices for these calculations. ##TABLE_START Years Ended December 31, 2022 2021 2020 Residential Revenue per customer (in dollars): $ 1,362 $ 1,320 $ 1,226 Usage per customer (in kilowatt hours): 9,991 9,968 9,804 Revenue per kilowatt hour (in cents): 13.63 13.24 12.50 Commercial Revenue per customer (in dollars): $ 6,491 $ 6,303 $ 5,684 Usage per customer (in kilowatt hours): 63,923 64,478 61,837 Revenue per kilowatt hour (in cents): 10.15 9.78 9.19 Industrial Revenue per customer (in dollars): $ 1,156,371 $ 1,044,314 $ 921,540 Usage per customer (in kilowatt hours): 22,097,472 20,002,246 18,472,161 Revenue per kilowatt hour (in cents): 5.23 5.22 4.99 ##TABLE_ENDFor additional information, see the Results of Operations section in Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. In addition to standard cost-of-service pricing, the Company offers different pricing options including a daily market price option, various time-of-use options, and several renewable energy options. For additional information on customer options, see Customer Choice Programs within this Customers and Revenues section of this Item 1. Residential customers include single family housing, multiple family housing (such as apartments, duplexes, and town homes), mobile homes, and small farms. Residential demand is sensitive to the effects of weather. The Company had seen its highest peak demand during the winter heating season although increased use of air conditioning in PGEs service territory has caused the summer peaks to increase over time. In recent years, including 2022, summer peaks have exceeded winter peaks and long-term load forecasts expect that trend to continue. An extreme winter temperature event on December 22, 2022, caused a new winter peak for the first time since 1998. Economic conditions can also affect residential demand as job growth and population growth in PGEs service territory have led to increased customer growth rates. The COVID-19 pandemic has introduced additional behavioral patterns as residential customers spend more time at home. Residential demand is also impacted by energy efficiency measures and increased rooftop solar penetration in the service territory; however, the Companys decoupling mechanism was intended to mitigate the financial effects of such measures. For further information regarding the decoupling mechanism, see Decoupling among the Regulatory Matters in the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Commercial customers consist of non-residential customers who accept energy deliveries at voltages equivalent to those delivered to residential customers. This customer class includes most businesses, small industrial companies, and public street and highway lighting accounts. The Companys commercial customer demand is somewhat less susceptible to weather conditions than residential customer demand. Economic conditions and fluctuations in total employment in the region can lead to changes in energy demand from commercial customers. Energy efficiency measures also impact commercial demand, as measures have focused in the commercial sector in recent years, although the Companys decoupling mechanism was intended to partially mitigate the financial

effects of such measures. For further information regarding the decoupling mechanism, see Decoupling among the Regulatory Matters in the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Industrial customers consist of non-residential customers who accept delivery at higher voltages than commercial customers, with pricing based on the amount of electricity delivered under the applicable tariff. Demand from industrial customers is primarily driven by economic conditions, with weather having little impact on this customer class. Customer Choice Programs Under cost-of-service pricing, residential and small commercial customers may select portfolio options from PGE that include time-of-use and renewable resource pricing. Pricing options other than cost-of-service are available to certain commercial and industrial customers for a one-year period, including daily market index-based pricing under which the Company provides the electricity, and Direct Access, whereby customers purchase electricity directly from an ESS. PGE receives revenue from Direct Access customers only for the transmission and delivery of the volume of electricity delivered, along with fixed transition adjustments intended to mitigate the shifting of excess charges to the Companys cost-of-service customers. Certain large commercial and industrial customers may elect a fixed three-year or a minimum five-year term, to be served either by an ESS, or by the Company under the daily market index-based price option. Participation in the fixed three-year and minimum five-year opt-out programs for existing and planned load is capped at 300 average megawatts (MWa) in aggregate. In 2020, the OPUC issued an order that required PGE to begin offering, to eligible customers, enrollment in the New Large Load Direct Access program, which is capped at 119 MWa in total, for unplanned, large, new loads and large load growth at existing sites. For further information regarding Direct Access deliveries, see Customers and demand in the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. PGEs customers have a desire for purchasing clean energy, as over 234 thousand residential and small commercial customers voluntarily participate in PGEs Green Future Program, the largest renewable power program by participation in the nation. Oregons most populous city, Portland, and most populous county, Multnomah, have each passed resolutions to achieve 100 percent clean and renewable electricity by 2035 and 100 percent economy-wide clean and renewable energy by 2050. Other jurisdictions in PGEs service area have set, or are considering, similar goals. The Company implemented a new customer service option, the Green Future Impact Program, which allows for 100 MW of PGE-provided power purchase agreements for renewable resources and up to 200 MW of customer-provided renewable resources. Approved by the OPUC in 2019, the program provides business customers access to bundled renewable attributes from those resources. In March 2021, the OPUC issued an order that expanded the program by 200 MW and provided for the possibility of PGE ownership of the underlying renewable resources under certain conditions. Through this voluntary program, the Company seeks to align sustainability goals, cost and risk management, and reliable integrated power while

providing customer choice and a cleaner energy system. In December 2021, the OPUC issued an order, which approved a petition to increase capacity under the customer-provided renewable resources by 250 MW, which brings the total available capacity under the program to 750 MW. For more information on the Companys power purchase agreements that currently serve the Green Future Impact Program, see Green Future Impact Program within Purchased Power in the Power Supply section of this Item 1. Wholesale Revenues PGE participates in the wholesale electricity marketplace in order to balance its supply of power to meet the needs of its retail customers. Interconnected transmission systems in the western United States serve utilities with diverse load requirements and allow the Company to purchase and sell electricity, largely through bi-lateral agreements, within the region to serve retail demand. PGEs engagement in the wholesale electricity marketplace depends upon numerous factors, including the relative price and availability of power, hydro and wind conditions, and daily and seasonal retail demand. The Company also participates in the California Independent System Operators western Energy Imbalance Market (western EIM), which allows for load balancing with other western EIM participants in five-minute intervals. Wholesale revenues represented 14% of total revenues in 2022, 11% in 2021, and 8% in 2020. Other Operating Revenues Other operating revenues consist primarily of gains and losses on the sale of natural gas volumes purchased that exceeded what was needed to fuel the Companys generating facilities, as well as revenues from transmission services, excess transmission capacity resales, pole attachment rentals, and other electric services provided to customers. Other operating revenues represented 2% of total revenues in 2022, 3% in 2021, and 2% in 2020. Seasonality Demand for electricity by PGEs residential and, to a lesser extent, commercial customers is affected by seasonal weather conditions. The Company uses heating and cooling degree-days to determine the effect of weather on the demand for electricity. Heating and cooling degree-days, determined by taking the difference between the average daily temperature and a baseline of 65 degrees, provide cumulative variances over a period of time, to indicate the extent to which customers are likely to have used electricity for heating or cooling. The higher the number of degree-days, the greater the expected demand for electricity. The following table presents the heating and cooling degree-days for the most recent three-year period, along with current 15-year averages for the most recent year provided by the National Weather Service, as measured at Portland International Airport: ##TABLE_START Heating Degree-Days Cooling Degree-Days 2022 4,103 865 2021 3,828 838 2020 3,836 600 15-year average 4,103 569 ##TABLE_ENDIn June 2021, PGE set a new all-time high net system load peak of 4,453 megawatts (MW), surpassing the previous all-time peak that occurred in December 1998 by more than 9%. While the Companys previous summer peak of 3,976 MW had occurred in August 2017, that level has been exceeded now in each of the past two summers. In December 2022, a new winter peak of 4,113 MW occurred. The following table presents PGEs average winter (defined as January, February, and December) and summer (defined as June through September) loads for the periods

presented, along with the corresponding peak load (in MWs) and month in which such peak occurred. As illustrated, although the average winter loads continue to exceed average summer loads, the Company has seen its highest annual peak loads during the summer months in recent years: ##TABLE_START Winter Loads Summer Loads Average Peak Month Average Peak Month 2022 2,773 4,113 December 2,529 4,255 July 2021 2,659 3,629 December 2,492 4,453 June 2020 2,566 3,367 December 2,289 3,771 July ##TABLE_ENDThe Company tracks and evaluates both load growth and peak load requirements for purposes of long-term load forecasting, integrated resource planning, and preparing general rate case assumptions. Behavior patterns, conservation, energy efficiency initiatives and measures, weather effects, economic conditions, distributed generation including rooftop solar, transportation and building electrification, and demographic changes all play a role in determining expected future customer demand and the resulting resources the Company may need to adequately meet those loads and maintain adequate capacity reserves. Power Supply PGE utilizes its generating resources, as well as wholesale power purchases from third parties to meet the needs of its retail customers. The volume of electricity the Company generates is dependent upon, among other factors, the capacity and availability of its generating resources and the price and availability of wholesale power and natural gas. As part of its power supply operations, the Company enters into short- and long-term power and fuel purchase and sale agreements. PGE executes economic dispatch decisions concerning its own generation and participates in the wholesale market in an effort to obtain reasonably-priced power for its retail customers, manage risk, and administer its long-term wholesale contracts. The Company also performs portfolio management and wholesale market sales services for third parties in the region. The Company also encourages energy efficiency measures to help meet its energy requirements and promotes the use of various demand side management products to reduce load during peak time usage. PGEs resource and contracted capacity (in MW) was as follows: ##TABLE_START As of December 31, 2022 2021 Capacity % Capacity % Generation: Thermal (1) : Natural gas 1,842 32 % 1,842 35 % Coal 296 4 296 5 Total thermal 2,138 37 2,138 40 Wind (2) 817 15 817 16 Hydro (3) 419 7 495 9 Total generation 3,374 59 3,450 65 Purchased power: Long-term contracts: Hydro (3) 871 15 803 15 PURPA qualifying facilities (4) 315 5 298 6 Dispatchable standby generation 130 2 130 2 Capacity 100 2 100 2 Wind (2) 300 5 300 6 Solar (5) 57 1 7 Biomass 10 10 Total long-term contracts 1,783 31 1,648 31 Short-term contracts 597 10 216 4 Total purchased power capacity 2,380 41 1,864 35 Total resource capacity 5,754 100 % 5,314 100 % ##TABLE_END##TABLE_START ##TABLE_END(1) Capacity represents the MW the plants are capable of generating under normal operating conditions, which is affected by ambient temperatures, net of electricity used in the operation of the plant. (2) Capacity represents nameplate and differs from expected energy to be generated, which is expected to have a capacity factor range from 30 to 40%, dependent upon wind conditions. (3) Capacity represents net capacity and differs from expected energy to be generated, which is expected to have a capacity factor range from 40 to 50%,

dependent upon river flows. (4) Capacity represents contracted capacity for power purchase agreements (PPAs) under the Public Utility Regulatory Policies Act of 1978 (PURPA). (5) Capacity includes 50 MW from the solar component of Wheatridge. The Wheatridge facility also includes 30 MW related to the battery component which is not reflected in the table above. For information regarding actual generating output and purchases for the years ended December 31, 2022 and 2021, see the Results of Operations section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Generation PGEs generating resources consist of six thermal plants (natural gas- and coal-fired), three wind farms, and seven hydroelectric facilities. The portion of PGEs retail load requirements generated by its plants varies from year to year and is determined by various factors, including planned and unplanned outages, availability and price of coal and natural gas, precipitation and snow-pack levels, the market price of electricity, and wind variability. For a complete listing of these facilities, see Generating Facilities in Item 2.Properties. Thermal The Company has five natural gas-fired generating facilities: PW1, PW2, Beaver, Coyote Springs Unit 1 (Coyote Springs), and Carty Generating Station (Carty). The Company operated, and continues to have a 90% ownership interest in the Boardman coal-fired generating plant (Boardman), which ceased coal-fired operations during the fourth quarter of 2020. The Company has begun decommissioning the facility. The Company also has a 20% ownership interest in the Colstrip Units 3 and 4 coal-fired generating plant (Colstrip), which is located in Colstrip, Montana and operated by a third party. For additional information on Colstrip as it relates to environmental laws and regulations in the State, see RPS standards and other laws in the Overview section in Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations and Note 19, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data. Wind PGE owns and operates two wind farms, Biglow Canyon Wind Farm (Biglow Canyon) and Tucannon River Wind Farm (Tucannon River). Biglow Canyon, located in Sherman County, Oregon, consists of 217 turbines with a total nameplate capacity of 450 MW. Tucannon River, located in southeastern Washington, consists of 116 turbines with a total nameplate capacity of 267 MW. During 2020, the wind component of the Wheatridge Renewable Energy Facility (Wheatridge), located in Morrow County, Oregon, was placed into service. Although PGE does not operate Wheatridge, it owns 40 turbines with a total nameplate capacity of 100 MW and purchases the output of the remaining turbines, with a nameplate capacity of 200 MW through power purchase agreement. PGE and NextEra Energy Resources, LLC, a subsidiary of NextEra Energy, Inc. have entered into agreements to construct a 311 MW wind energy facility, which will be part of the larger Clearwater Wind development in Eastern Montana. This additional wind capacity is not reflected in the table above. For more information regarding the Clearwater Wind development, see The Resource Planning Process within the Overview section of Item 7 Managements Discussion and Analysis of Financial Condition and Results of Operations. Hydro The Companys FERC-licensed

hydroelectric projects consist of Pelton/Round Butte on the Deschutes River near Madras, Oregon (discussed below), four plants on the Clackamas River, and one on the Willamette River. As of December 31, 2021, PGE had a 66.67% ownership interest in the 455 MW Pelton/Round Butte hydroelectric project on the Deschutes River, with the remaining interest held by the Confederated Tribes of the Warm Springs Reservation of Oregon (CTWS). A 50-year joint license for the project, which is operated by PGE, was issued by the FERC in 2005. The CTWS had an option to purchase an additional undivided 16.66% ownership interest in Pelton/Round Butte in 2021, and closed on the purchase of this incremental undivided ownership interest on January 1, 2022. As a result, PGEs ownership interest in the project is 50.01%. CTWS has a second option in 2036 to purchase an undivided 0.02% interest in Pelton/Round Butte. If the second option is exercised, CTWSs ownership percentage would exceed 50%. PGE purchases 100% of the CTWSs share of the project output. For more information see CTWS within Purchased Power in the Power Supply section of this Item 1. Fuel Supply PGE contracts for natural gas and coal supplies required to fuel the Companys thermal generating plants, with certain plants also able to operate on fuel oil, if needed. In addition, the Company uses forward, future, swap, and option contracts to manage its exposure to volatility in natural gas prices. Natural Gas Physical supplies of natural gas are generally purchased up to twelve months in advance of delivery and based on anticipated operation of the plants. PGE manages the price risk of natural gas supply through the use of financial contracts up to 60 months in advance of expected need of energy. PGE owns 79.5%, and is the operator of record, of the KB Pipeline, which directly connects PW1, PW2, and Beaver to the Northwest Pipeline, an interstate natural gas pipeline operating between British Columbia and New Mexico. Currently, PGE transports natural gas on the KB Pipeline for its own use under a firm transportation service agreement, with capacity offered to others on an interruptible basis to the extent not utilized by the Company. PGE has access to 111,805 Dth per day of firm natural gas transportation capacity on the Northwest Pipeline to serve the three plants. PGE has access to 4.1 billion cubic feet of natural gas storage in Mist, Oregon from which it can draw when economic factors favor its use or in the event that natural gas supplies are interrupted. The storage facility, owned and operated by NW Natural, may be utilized to provide fuel to PW1, PW2, and Beaver. To serve Coyote Springs and Carty, PGE has access to 120,000 Dth per day of firm natural gas transportation capacity on three pipeline systems accessing gas fields in Alberta, Canada. Coal The Colstrip co-owners obtain coal to fuel the plant via conveyor belt from a mine that lies adjacent to the facility and is the sole source of coal supply for the plant. The coal supply contract with the owner of the mine is scheduled to expire at the end of 2025. The terms of the contract and the quality of coal are expected to allow the facility to operate within required emissions limits. Purchased Power PGE supplements its own generation with power purchased in the wholesale market to meet its retail load requirements. The Company utilizes short- and long-term wholesale power purchase contracts in an effort to provide the most favorable economic mix on a variable cost

basis. PGEs medium-term power cost strategy helps mitigate the effect of price volatility on its customers due to changing energy market conditions. The strategy allows the Company to take positions in power and fuel markets up to five years in advance of physical delivery. By purchasing a portion of anticipated energy needs for future years over an extended period, PGE mitigates a portion of the potential future volatility in the average cost of purchased power and fuel. The Companys major power purchase contracts consist of the following (also see the preceding table which summarizes the average resource capabilities related to these contracts): Hydro During 2022, the Company had the following agreements: Public Utility Districts PGE has long-term power purchase contracts with certain public utility districts (PUDs) in the state of Washington for a portion of the output of two hydroelectric projects on the mid-Columbia River. Although the projects currently provide PGE a total of 410 MW of capacity through contracts as shown below, actual energy received is dependent upon river flows and capacity amounts may decline over time: 162 MW of capacity with Grant County PUD that expires in 2052; 148 MW of capacity with Douglas County PUD that expires in 2028; and 100 MW of capacity with Douglas County PUD that expires in 2025. CTWS PGE has a long-term agreement under which the Company purchases output from CTWS interest in the Pelton/Round Butte hydroelectric project. Although the agreement provides approximately 224 MW of net capacity, actual energy received is dependent upon river flows. The term of the agreement coincides with the term of the FERC license for this project, which expires in 2055. Under a separate PPA executed in 2014, PGE pays fixed capacity and energy charges to CTWS for 100% of its share of the project through 2024. On June 30, 2021 the CTWS notified PGE of their intent to exercise their option to purchase an additional undivided 16.66% ownership interest in Pelton/Round Butte and closed on the purchase on January 1, 2022. As a result of the sale, capacity from company-owned generation decreased by approximately 76 MW, and capacity from purchased power increased by a corresponding amount. Under the PPA, PGE purchases 100% of the CTWSs additional share of the project and payments under the PPA increase proportionately. In the fourth quarter of 2021, PGE and CTWS executed an additional 16-year PPA which begins on January 1, 2025, that effectively extends the term from 2024 to 2040 and increases the capacity payments in the extension period. Other The remaining capacity is primarily comprised of two additional contracts that provide for the purchase of power generated from hydroelectric projects with capacity of 236 MW in total: 200 MW of capacity with Bonneville Power Administration that expires in 2024; and 36 MW of capacity with Portland Hydro that expires in 2032 PURPA qualifying facilities PGE is required to purchase power from PURPA qualifying facilities (QFs), as mandated by federal law. QFs are generating facilities that fall within the following two categories: i) qualifying generation facilities with a capacity of 80 MW or less and whose primary energy source is renewable (hydro, wind, solar, biomass, waste, or geothermal); or ii) qualifying cogeneration facilities that sequentially produce electricity and another form of useful thermal energy (e.g., heat, steam) in a way that is more efficient than the separate production of each form of

energy. As of December 31, 2022, PGE had contracts with 67 online QFs, providing a total of 315 MW of capacity. As of December 31, 2022, PGE has six contracts with QFs representing 127 MW of capacity that are not yet operational, of which two of the QF PPAs are in default because the QF has failed to complete construction and become operational by the date required by the PPA. The PPAs provide that the QF has one year to cure its default. If the QF has failed to cure, PGE is permitted to immediately terminate the QF PPA upon expiration of the cure period. The term of a QF PPA generally ranges from 15 to 23 years. The expense and volume of purchases from QFs for the years ended December 31, 2022 and 2021 were as follows: ##TABLE_START 2022 2021 PURPA contract expense (in millions) $ 62 $ 55 MWh purchased under PURPA contracts (in thousands) 750 683 Average cost per MWh from PURPA contracts $ 82.90 $ 79.89 ##TABLE_ENDExpenses incurred related to PURPA contracts are included in PGEs AUT. Dispatchable Standby Generation (DSG) PGE has a DSG program under which the Company can start, operate, and monitor customer-owned backup generators when needed to provide NERC-required operating reserves. As of December 31, 2022, there were 59 customer-owned sites with a total DSG capacity of 130 MW. PGE continues to pursue expansion of the program with the goal of having an additional 3 to 10 MW of customer-owned DSG projects online by the end of 2023. Capacity PGE has one capacity contract representing up to 100 MW of seasonal capacity during the summer and winter peak periods obtained from a natural gas-fired resource, which expires in 2024. Wind PGE has three contracts representing 300 MW of capacity to purchase power generated from renewable wind resources that extend to 2028, 2035, and 2051. The expected energy from these wind resources will vary from the nameplate capacity due to varying wind conditions. PGE and NextEra Energy Resources, LLC, a subsidiary of NextEra Energy, Inc. have entered into agreements to construct a 311 MW wind energy facility, which will be part of the larger Clearwater Wind development in Eastern Montana. This additional wind capacity is not reflected in the table above. For more information regarding the Clearwater Wind development, see The Resource Planning Process within the Overview section of Item 7 Managements Discussion and Analysis of Financial Condition and Results of Operations. Solar PGE has four contracts representing 57 MW of capacity to purchase power generated from photovoltaic solar projects. Two of these projects extend to 2036 while the other two extend to 2037 and 2042. The expected energy from these solar resources will vary from the nameplate capacity due to varying solar conditions. Construction on the solar and battery components of Wheatridge was completed in 2022. The solar component of Wheatridge supplies the Company with 50 MW of capacity. The facility also includes 30 MW related to the battery component which is not reflected in the table above. Subsidiaries of NextEra Energy Resources, LLC own the solar and battery components, and sell their portion of the output to PGE. Biomass PGE has one contract to purchase biomass energy that is set to expire in June 2023. Green Future Impact Program PGE has three contracts representing 360 MW of capacity to purchase power generated from renewable resources to support the Green Future

Impact Program: a 15-year contract with Avangrid Renewables representing 162 MW from a renewable solar facility in Gilliam County, Oregon that was placed in service in January 2023. This additional capacity is not reflected in the table above; and a 15-year contract with Avangrid Renewables representing 138 MW from a renewable solar facility in Wasco County, Oregon that is expected to be placed in service in December 2023. This additional capacity is not reflected in the table above. a 15-year contract with Avangrid Renewables representing 60 MW from a renewable solar facility in Wasco County, Oregon that is expected to be placed in service in December 2023. This additional capacity is not reflected in the table above. For additional information on the Green Future Impact Program, see Customer Choice Programs within the Customers and Revenues section of this Item 1. Short-term contracts These contracts are for delivery periods of one month up to one year in length. They are entered into with various counterparties to provide additional firm energy to help meet the Companys load requirements. PGE also utilizes spot purchases of power in the open market to secure the energy required to serve its retail customers. Such purchases are made under contracts that range in duration from 15 minutes to less than one month. PGE is a market participant in the western EIM, which allows certain of the Companys generating plants to receive automated dispatch signals from the California Independent System Operator (CAISO) for load balancing with other western EIM participants in five-minute intervals. For additional information regarding PGEs power purchase contracts, see Note 16, Commitments and Guarantees and Note 17, Leases, in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data. Future Energy Resource Strategy PGEs Integrated Resource Plan (IRP) outlines the Companys plan to meet future customer demand and describes PGEs future energy supply strategy. For a detailed discussion of the IRPs, see Investing in a Clean Energy Future within the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Transmission and Distribution Transmission systems deliver energy from generating facilities to distribution systems for final delivery to customers. PGE schedules energy deliveries over its transmission system in accordance with FERC requirements and operates one BAA in its service territory. In 2022, PGE delivered approximately 27 million megawatt hours (MWh) through 1,255 circuit miles of transmission lines operating at or above 115 kilovolts (kV). PGEs transmission system is part of the Western Interconnection, the regional grid in the western United States. The Western Interconnection includes the interconnected transmission systems of 11 western states, two Canadian provinces and parts of Mexico, and is subject to the reliability rules of the WECC and the NERC. PGE relies on transmission contracts with Bonneville Power Administration (BPA) to transmit a significant amount of the Companys generation to serve its distribution system. PGEs transmission system, together with contractual rights on other transmission systems, enables the Company to integrate and access generation resources to meet its customers energy requirements. PGEs generation is managed on a coordinated basis to obtain maximum load-carrying capability and efficiency. PGE has announced its

intention to join the Western Power Pool and a binding resource adequacy program for the region known as the Western Resource Adequacy Program (WRAP). For further information, see Operating Activities within the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. The Companys wholesale transmission activities are regulated by the FERC and are offered on a non-discriminatory basis, with all potential customers provided equal access to PGEs transmission system through PGEs OATT. In accordance with its OATT, PGE offers several transmission services to wholesale customers, including: Network integration transmission service, a service that integrates generating resources to serve retail loads; Short- and long-term firm point-to-point transmission service, a service with fixed delivery and receipt points; and Non-firm point-to-point service, an as available service with fixed delivery and receipt points. For additional information regarding the Companys transmission and distribution facilities, see Transmission and Distribution in Item 2.Properties. Environmental Matters PGEs operations are subject to a wide range of environmental protection laws and regulations, which pertain to air and water quality, endangered species and wildlife protection, and hazardous material. Various state and federal agencies also regulate environmental matters that relate to the siting, construction, and operation of generation, transmission, and substation facilities and the handling, accumulation, clean-up, and disposal of toxic and hazardous substances. In addition, certain of the Companys hydroelectric projects and transmission facilities are located on property under the jurisdiction of federal and state agencies, and/or tribal entities that have authority in environmental protection matters. The following discussion provides further information on certain environmental regulations that affect the Companys operations and facilities. Air Quality Clean Air Act PGEs operations, primarily its thermal generating plants, are subject to regulation under the federal Clean Air Act (CAA), which addresses particulate matter, hazardous air pollutants, and GHG emissions, among other things. Oregon and Montana, the states in which PGEs thermal facilities are located, also implement and administer certain portions of the CAA and have set standards that are at least as stringent as federal standards. PGE manages its air emissions at its thermal generating plants by the use of low sulfur fuel, emissions and combustion controls and monitoring, and sulfur dioxide allowances awarded under the CAA. Climate Change In 2015, the United States Environmental Protection Agency (EPA) released the Clean Power Plan (CPP), under which each state would have to reduce overall carbon dioxide emissions from its power sector on a state-wide basis. In 2016, the United States Supreme Court halted implementation and enforcement of the CPP. In 2018, the EPA proposed the more narrowly focused Affordable Clean Energy (ACE) rule, to repeal and replace the CPP and, in 2019, finalized the ACE rule, which established guidelines for states to develop plans to address GHG emissions from individual, existing coal-fired plants, such as Colstrip in the case of PGE. With the finalization of the ACE rule, the CPP was repealed. However, on January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE rule and remanded it, in full, back to the EPA. Notwithstanding

objections that the EPA intended to issue a new rule that took recent changes in the electricity sector into account, on October 29, 2021, the U.S. Supreme Court agreed to hear an appeal of the D.C. Circuit decision. The Supreme Court, in a February 28, 2022 decision, determined that the broad approach in the CPP regulating emissions exceeded the powers granted to EPA by Congress. The Court did not expressly determine whether EPA can regulate power sector GHG emissions through its other regulatory authority and the EPA has indicated it intends to issue a proposed successor rule to the CPP in March 2023. PGE will continue to assess the Supreme Courts decision, as well as any further EPA response, for impacts on Colstrip and the Companys existing natural gas fleet. House Bill (HB) 2021 In June 2021, the Oregon Legislature passed HB 2021, which requires retail electricity providers to reduce GHG emissions associated with serving Oregon retail electricity consumers 80% by 2030, 90% by 2035, and 100% by 2040, compared to their baseline emissions levels. The baseline levels for PGE are the average annual emissions for the years 2010, 2011, and 2012 associated with the electricity sold to its retail electricity consumers as reported to the Oregon Department of Environmental Quality (ODEQ). See HB 2021 in the Laws and Regulations section of the Overview for additional information. Any laws that would impose taxes or mandatory reductions in GHG emissions may have a material impact on PGEs operations, as the Company utilizes fossil fuels in its own power generation and other companies use such fuels to generate power that PGE purchases in the wholesale market. If incremental costs were incurred as a result of changes in the regulations regarding GHG emissions, the Company would seek recovery in customer prices. For more information regarding GHG emissions and related environmental regulation, including Oregons RPS and the Companys goals in this area, see Renewable Energy under State Regulation in the Regulation section of this Item 1. and Company Strategy in the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Water Quality The federal Clean Water Act requires that any federal license or permit to conduct an activity that may result in a discharge to waters of the United States must first receive a water quality certification or permit from the state in which the activity will occur. In Oregon, Montana, and Washington, the Department of Environmental Quality and Department of Ecology of each state are responsible for reviewing proposed projects under such requirements to ensure that federally approved activities will meet water quality standards and policies established by the respective state. PGE has obtained permits or certificates of compliance for its hydroelectric operations under the FERC licenses and continues to monitor and update equipment to meet federal and state standards. Threatened and Endangered Species and Wildlife Fish Protection The federal Endangered Species Act (ESA) has granted protection to many populations of migratory fish species in the Pacific Northwest. Long-term recovery plans for these species continue to have operational impacts on many of the regions hydroelectric projects. PGE continues to implement fish protection measures at its hydroelectric projects that were prescribed by the U.S. Fish and Wildlife Service and the National

Marine Fisheries Service under their authority granted in the ESA and the FPA. Conditions required with the operating licenses are expected to result in a minor reduction in power production and continued capital spending to modify the facilities to enhance fish passage and survival. Avian Protection Various statutes, including the Migratory Bird Treaty Act and Bald and Golden Eagle Protection Act, contain provisions for civil, criminal, and administrative penalties resulting from the unauthorized take of migratory birds and eagles. Because PGE operates facilities that can pose risks to a variety of such birds and eagles, the Company developed an Avian Protection Plan to help address and reduce risks to avian species that may be affected by Company operations. PGE has implemented such a plan for its transmission, distribution, and thermal generation facilities and additional, specific plans for its wind generation facilities. Hazardous Material PGE has a comprehensive program to comply with requirements of both federal and state regulations related to the storage, handling, and disposal of hazardous materials. The handling and disposal of hazardous materials from Company facilities is subject to regulation under the federal Resource Conservation and Recovery Act. In addition, the use, disposal, and clean-up of polychlorinated biphenyls, contained in certain electrical equipment, are regulated under the federal Toxic Substances Control Act. PGE is also subject to the Comprehensive Environmental Response Compensation and Liability Act, commonly referred to as Superfund, which provides authority to the EPA to assert joint and several liability for investigation and remediation costs for designated Superfund sites. An investigation by the EPA that began in 1997 of a segment of the Willamette River in Oregon known as Portland Harbor, revealed significant contamination of river sediments and prompted the EPA to designate Portland Harbor as a Superfund site. The EPA has listed PGE among the more than one hundred Potentially Responsible Parties (PRPs) in this matter, as PGE historically owned or operated property near the river. For additional information regarding the EPA action on Portland Harbor, see Note 19, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data. PGE is subject to regulation by the United States Department of Energy (USDOE), which, under the Nuclear Waste Policy Act of 1982, is responsible for the permanent storage and disposal of spent nuclear fuel. PGE has contracted with the USDOE for permanent disposal of spent nuclear fuel from Trojan that is stored in the Independent Spent Fuel Storage Installation (ISFSI), an NRC-licensed interim dry storage facility that houses the fuel. The NRC approved the transfer of spent nuclear fuel from a spent fuel pool to the ISFSI where it is expected to remain until permanent off-site storage is available. Shipment of the spent nuclear fuel from the ISFSI to off-site storage is not expected to be completed prior to 2059. For additional information regarding this matter, see Trojan decommissioning activities in Note 8, Asset Retirement Obligations, in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data. Human Capital Management PGEs talent and culture are vital to its ability to execute its business strategy and realize continued success. Accordingly, the Company seeks to attract and retain a talented,

motivated, and diverse workforce and maintain a culture that reflects PGEs Guiding Behaviors, drive for performance, and commitment to acting with the highest levels of honesty, integrity, compliance, and safety. Employees and Collective Bargaining Agreements PGE had 2,873 employees in its workforce as of December 31, 2022, with 673 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers (IBEW). One agreement covers 610 employees, which expires March 2025, and the other covers 63 employees, which expires August 2027. The partnership with IBEW is key to a holistic labor relations approach. In addition, PGE utilizes independent contractors and temporary personnel to supplement its workforce. Competitive Pay and Benefits PGE is committed to pay equity among its employees and offers a wide range of market-competitive benefits, including comprehensive health and welfare benefits and a 401(k) retirement plan, designed to support the physical, mental, and financial well-being of its employees. Talent Development PGE provides a variety of training and development programs for employees, as well as tuition reimbursement for job-related coursework. PGE offers a mentorship program for all regular, non-represented PGE employees to help support their growth and development. The PGE Board of Directors oversees executive talent development with the assistance of the Nominating, Governance, and Sustainability Committee and the Compensation, Culture and Talent Committee in an effort to maximize the pool of internal candidates. At least annually, the Board conducts reviews of succession plans for senior management, which includes a review of the qualifications and development plans of potential internal candidates and diversity of the succession pipeline. The Compensation, Culture and Talent Committee regularly conducts more in-depth reviews of development plans for promising management talent. PGE conducts employee engagement surveys periodically to give employees the opportunity to share their perspectives and provide feedback. Survey results are shared with PGE management so that managers can take action towards improving the employee experience. Health and Safety PGE is committed to providing a safe and healthy place of business for employees, customers, and the public. Management has established an Executive Safety Council that has oversight of the Companys efforts to create a safe workplace. In addition, PGE provides various safety resources to its employees, such as safety manuals, trainings, and incident reporting tools that are all designed to incorporate safe practices into all daily activities and promote in all employees a sense of personal commitment, responsibility, and obligation regarding safety. PGE also has an Employee Assistance Program that provides free and confidential wellness counseling to all employees and their families. Diversity, Equity, and Inclusion PGE promotes an inclusive workforce through pay equity practices, racial equity training, and development opportunities for women and people of color to advance into management. Black, Indigenous, and People of Color comprise over 26% of its employees and nearly 26% of management. One third of its employees and management, including its CEO, are female. PGE also promotes diversity and economic development through its suppliers. The Companys supplier diversity program

provides an opportunity in all competitive bid events for qualified minority-owned, women-owned, disabled veteran-owned, and emerging small business suppliers. COVID-19 Since the beginning of the COVID-19 pandemic, PGE has taken steps to protect employees. The Company continues to prioritize the health and safety of its employees and be informed by federal, state and local officials to align its efforts with current information. Information about Executive Officers The following are PGEs current executive officers: ##TABLE_START Name Age Current Position and Previous Experience Year Appointed Officer James A. Ajello 69 Senior Vice President, Finance, Chief Financial Officer, Treasurer and Corporate Compliance Officer (January 2021 to present), Senior Advisor (November 2020 to December 2020), Executive Vice President and Chief Financial Officer at Hawaiian Electric Industries (January 2009 to April 2017 - retired), Senior Vice President, Business Development at Reliant Energy (January 2000 to January 2009), Managing Director, UBS Securities (January 1984 to August 1998). 2021 Larry N. Bekkedahl 61 Senior Vice President, Advanced Energy Delivery (July 2021 to present), Vice President, Grid Architecture, Integration and Systems Operations (January 2019 to July 2021), Vice President Transmission and Distribution (August 2014 to January 2019). Senior Vice President of Transmission Services at BPA (June 2012 to August 2014), Vice President of Engineering and Technical Services at BPA (2008 to June 2012). 2014 Nicholas G. Blosser 52 Vice President Public Affairs (August 2022 to present), Chief of Staff and Deputy Cabinet Secretary and Special Assistant to the President, Office of Cabinet Affairs at The White House (March 2021 to July 2022), Intergovernmental Affairs and State Lead, Biden-Harris Transition Team (November 2020-January 2021), Chief of Staff for Oregon Governor Kate Brown (February 2017 to November 2020), Co-Founder and CEO of Celilo Group Media, Inc. (January 2000 to February 2017) 2022 M. Angelica Espinosa 45 Vice President, General Counsel (March 2022 to present), Deputy General Counsel and Corporate Secretary (June 2021 to March 2022), Chief Risk Officer and Vice President of Safety and Compliance at Southern California Gas Company (January 2019 to June 2021), Vice President, Compliance Governance and Corporate Secretary at Sempra Energy (November 2016 to January 2019) 2022 Bradley Y. Jenkins 59 Vice President, Utility Operations (January 2019 to present), Vice President, Generation and Power Operations (October 2017 to January 2019), Vice President, Power Supply Generation (September 2015 to October 2017), General Manager, Diversified Plant Operations, (November 2013 to August 2015), Plant General Manager, Boardman (September 2012 to November 2013), Operations Manager, Boardman (March 2012 to September 2012). 2015 John T. Kochavatr 49 Vice President, Information Technology and Chief Information Officer (February 2018 to present). Senior Vice President and Chief Information Officer at SUEZ Water Technologies Solutions (formerly General Electric Water and Process Technologies) (October 2017 to January 2018), Chief Information Officer and Chief Digital Officer at General Electric Water and Process Technologies (November 2012 to September 2017). 2018 ##TABLE_END##TABLE_START Anne F. Mersereau 60 Vice President, Human Resources, Diversity, Equity and Inclusion (January 2016 to present),

Employee Services Manager (January 2014 to January 2016), Change Management Consultant (January 2012 to January 2014), Human Resources Business Partner (July 2009 to December 2011). 2016 Maria M. Pope 57 President (October 2017 to present) and Chief Executive Officer (January 2018 to present), Senior Vice President, Power Supply, Operations and Resource Strategy (March 2013 to December 2017), Senior Vice President, Finance, Chief Financial Officer and Treasurer (January 2009 to February 2013). Board director (January 2006 to December 2008). Vice President and Chief Financial Officer for Mentor Graphics Corporation (July 2007 to December 2008). 2009 Brett M. Sims 54 Vice President, Strategy, Regulation and Energy Supply (October 2020 to present), Senior Director of Strategy, Commercial and Regulatory Affairs (September 2017 to October 2020), Director of Origination, Structuring Resource Strategy (May 2001 to September 2017). 2020 ##TABLE_END ITEM 1A. RISK FACTORS. When evaluating PGE and any investment in its securities, investors should consider carefully the following risk factors and all other information contained in this Annual Report on Form 10-K and in the other documents that the Company files from time to time with the SEC. The events described in the risk factors could have material effects on PGEs business, financial condition, results of operations, or cash flows, or that materially adversely affect PGEs results and cause such results to differ materially from projected results. Risk and uncertainties not currently known to the Company or that are currently deemed to be immaterial may also harm PGE. If any of these risks occur, PGEs business, financial condition, results of operations, and/or cash flows could be materially adversely affected, and the trading prices of the Companys securities could substantially decline. BUSINESS AND OPERATIONAL RISKS The effects of unseasonable or severe weather and other natural phenomena can adversely affect the Companys financial condition and results of operations, and the effects of climate change could result in more intense, frequent, and extreme weather events. Weather conditions can adversely affect PGEs revenues and costs, impacting the Companys results of operations. Variations in temperatures can affect customer demand for electricity, with warmer-than-normal winter seasons or cooler-than-normal summer seasons reducing the demand for energy. Weather conditions are the dominant cause of usage variations from normal seasonal patterns, particularly for residential customers. Rapid increases in load requirements resulting from unexpected weather changes, particularly if coupled with transmission constraints, could adversely impact PGEs cost and ability to meet the energy needs of its customers. Conversely, rapid decreases in load requirements could result in the sale of excess energy at depressed market prices. Changes in the global and local climate could result in more intense, frequent, and extreme weather events such as ice and snowstorms, high wind, flooding, changes in regional rainfall and snowpack levels, high heat events, drought conditions, and increased risk of wildfires. These events may disrupt energy delivery, cause power outages, and damage the Companys facilities and transmission and distribution system. Such events could result in a reduction in revenue and an increase in additional costs to restore service, repair facilities, purchase power and fuel to serve PGE load, and

procure insurance related to such impacts. In response to more intense, frequent, and severe weather events, PGE may need to make additional investments in generation, transmission, and distribution assets to enhance reliability and resiliency. Severe weather may also require increased PGE personnel availability, which could result in increased operating expenses as well increased safety risk. In certain instances, PGE relies on mutual aid support to assist in the recovery from severe weather. Lack of availability of mutual aid support could result in increased time to restore services to customers as well as increased costs and decreased customer satisfaction. Wildfires of greater size and prevalence, such as those of a magnitude seen in Oregon in recent years, could negatively affect public safety, the resilience of the electric grid, customers demand for power and PGEs ability and cost to procure adequate power and fuel supplies to serve its customers, PGE s ability to access the wholesale energy market, PGEs ability to operate its generating facilities and transmission and distribution systems, PGEs costs to maintain, repair, and replace such facilities and systems, and recovery of costs. PGE may be unable to effectively implement a public safety power shutoff (PSPS) and de-energize its system in the event of heightened wildfire risk, or the PSPS may not be able to prevent a wildfire, which could lead to potential liability if energized systems are determined to be the cause of wildfires that result in harm. Capital investment and operating expenses related to this risk may not be recoverable through increases in customer prices. Cybersecurity attacks, data security breaches, physical attacks and security breaches, acts of terrorism, or other similar events that could disrupt PGEs operations, require significant expenditures, or result in claims against the Company. In the normal course of business, PGE collects, processes, and retains sensitive and confidential customer and employee information, as well as proprietary business information, and operates systems that directly impact the availability of electric power and the transmission of electric power in its service territory. PGE owns and operates generation, transmission, distribution, and other facilities that depend on information technology systems. A cyber-attack may cause large-scale disruption to the U.S. bulk power system or PGE operations and could target the Companys computer systems, software, or networks to achieve such disruption. Generation, transmission, and distribution facilities, in general, have been identified as potential targets of physical or cyber-attacks. In addition, physical attacks on transmission and distribution facilities have occurred in the United States. Despite the security measures in place, the Companys systems and assets, and those of third-party service providers, could be vulnerable to cybersecurity attacks, data security breaches, physical attacks and security breaches, acts of terrorism, or other similar events that could disrupt operations, cause damage to the Companys generation, transmission, or distribution facilities, impact reliability of the transmission and distribution system, information technology systems, inhibit the capability of equipment or systems to function as designed or expected, prevent service to customers or collection of revenues, or result in the release of sensitive or confidential customer, employee, or Company information. Such events could cause a shutdown of service, expose PGE to

liability, or cause reputational damage. In addition, the Company may be required to expend significant capital and other resources to protect against security breaches or to alleviate problems caused by security breaches. A breach of certain business systems could impact PGEs ability to initiate, authorize, process, record, and report financial information. The cost of repairing damage to PGEs facilities and infrastructure caused by acts of terrorism, and the loss of revenue if such events prevent PGE from providing utility service to its customers, could adversely impact its financial condition and results of operations. PGE maintains insurance coverage against some, but not all, potential losses resulting from these risks. However, insurance is limited in scope and subject to exceptions, and may not be adequate to protect the Company against liability in all cases and insurers may dispute or be unable to perform their obligations to the Company, or may not be available at rates that are commercially reasonable. Natural or human-caused disasters and other risks could damage the Companys facilities and disrupt delivery of electricity resulting in significant property loss, repair costs, and reduced customer satisfaction. PGE has exposure to natural and human-caused disasters and other risks, including, but not limited to, a pandemic such as COVID-19, earthquake, accidents, equipment failure, acts of terrorism, acts of vandalism, computer system outages and other events. Such events, which may be amplified by the fact that PGEs business activities are concentrated in one region, could disrupt PGE operations, damage PGE facilities and systems, interrupt the delivery of electricity, increase repair and service restoration expenses, reduce revenues, cause the release of harmful materials, cause fires or flooding, and subject the Company to liability. Such events, if repeated or prolonged, can also affect customer satisfaction and the level of regulatory oversight. Electric utility operations may pose risk to public and workers safety. The operation of electric generation, transmission, and distribution infrastructure involves inherent risks, including breakdown or failure of equipment, motor vehicle accidents, fires involving the utilitys equipment, dam failure at company-owned hydroelectric facilities, public and worker safety, human contact with energized equipment, and operator error. A portion of the Companys operations relies on Company- or third party-owned natural gas transmission and distribution infrastructure and involves inherent risks, such as leaks, explosions, mechanical problems, and worker and public safety. These risks could cause significant harm to workers and the public including loss of human life, significant damage to property, adverse impacts on the environment and impairment of PGEs operations, all of which could result in financial losses that would have a material adverse effect on the Companys results of operations and financial condition. PGE is also required to comply with new and changing regulatory standards involving safety compliance. The cost to comply with such requirements could be significant, and failure to meet these regulatory standards could result in substantial fines. The inability to attract and retain a qualified workforce and to maintain satisfactory collective bargaining agreements without prolonged labor disruptions, may adversely affect PGEs results of operations. PGEs workforce includes a diverse mix of skilled professional, managerial, and technical employees, including employees represented

under collective bargaining agreements. Workforce management risks include the risk of retaining key employees, turnover due to demographic challenges as employees approach retirement age, and turnover due to macroeconomic trends such as the impacts of inflation on pensions and other retirement funding. PGE faces competition for employees within the industry and in local geographies. The Company faces the risk of labor disruption due to the outcomes of labor negotiations or the possibility that employees not currently subject to collective bargaining agreements may organize. PGE relies on a contracted workforce for specific business purposes, and may experience increased costs or inability to find contracted workforce, which may result in a negative impact on operations as well as financial impact. The construction of new facilities and the modifications or replacements of existing facilities, is subject to risks that could result in the disallowance of certain costs for recovery in customer prices or higher operating costs. Long-term increases in both the number of customers and demand for energy will require continued expansion and upgrade of PGEs generation, transmission, and distribution systems. Construction of new facilities and modifications or replacements of existing facilities could be affected by factors such as unanticipated delays and cost increases, including supply chain disruption and cost inflation, availability of skilled workforce, increases in interest rates, failure of counterparties to perform under agreements, and the failure to obtain, or delay in obtaining, necessary permits from state or federal agencies or tribal entities. Delays and cost increases could result in failure to complete the projects or the abandonment of capital projects, which could eliminate or impair PGEs ability to recover related costs in the rate determination process. In addition, failure to complete construction projects according to specifications could result in reduced plant efficiency, equipment failure, and plant performance that falls below expected levels, which could increase operating costs. REGULATORY, LEGAL, AND COMPLIANCE RISKS PGE is subject to extensive price regulation and relies on recovery of costs, the uncertainty of which affect the Companys operations and costs. PGE is subject to ongoing regulation by the FERC, the OPUC and by certain federal, state, and local authorities under environmental, permitting, and other laws. Such regulation significantly influences the Companys operating environment and affects many aspects of its business. The Company cannot predict with certainty the future course of such changes or the ultimate effect that they might have on its business, and such changes could delay or adversely affect business planning and transactions and substantially increase the Companys costs. OPUC regulates the prices that PGE charges, which is a major factor in determining the Companys operating income, financial position, liquidity, and credit ratings. As a general matter, PGE relies on customer prices to recover most of the costs incurred in connection with the operation of its business, including, among other things, costs related to capital projects (such as the construction of new facilities or the modification of existing facilities), the costs of compliance with legislative and regulatory requirements (including environmental laws), and the costs of damage from storms and other natural disasters. Regulators may deny recovery of costs it considers imprudently incurred. Although the

OPUC is required to establish customer prices that are fair, just, and reasonable, it has significant discretion in the interpretation of this standard. PGE attempts to manage its costs at levels consistent with OPUC-approved prices. However, if the Company is unable to do so, or if such cost management results in increased operational risk, the Companys financial and operating results could be adversely affected. PGE is subject to various legal and regulatory proceedings, the outcome of which is uncertain, and resolution unfavorable to PGE could adversely affect its results of operations, financial condition, or cash flows. In the normal course of its business, PGE is subject to regulatory proceedings, lawsuits, claims, and other matters, which could result in adverse judgments, settlements, fines, penalties, injunctions, or other relief. Such matters include governmental policies, legislative action, and regulatory audits, investigations, and actions, including those of the FERC and OPUC with respect to allowed rates of return, financings, electricity pricing and price structures, acquisition and disposal of facilities and other assets, construction and operation of plant facilities, transmission of electricity, recovery of power costs, operating expenses, deferrals, timely recovery of costs and capital investments, and current or prospective wholesale and retail competition. These matters are subject to many uncertainties, the ultimate outcome of which management cannot predict. The final resolution of certain matters in which PGE is involved could result in disallowance of operating expenses previously deferred or could require that the Company incur expenditures over an extended period and in a range of amounts that could have an adverse effect on its cash flows and results of operations. Similarly, the terms of resolution could require the Company to change its business practices and procedures, which could also have an adverse effect on its cash flows, financial position, or results of operations. New laws, changes in legal precedent, or novel interpretations of existing regulations could also result in adverse effects on cash flows and results of operations. There are certain pending legal and regulatory proceedings that may have an adverse effect on results of operations and cash flows for future reporting periods. For additional information, see Item 3.Legal Proceedings, Regulatory Matters within the Overview of Item 7. Managements Discussion and Analysis of Financial Condition and Results of Operations, and Note 19, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data. Compliance with environmental laws and regulations may result in capital expenditures, increased operating costs and various liabilities, and adverse impact on the Companys results of operations. PGE is subject to various environmental laws, regulations, and other standards including federal, state and local environmental statutes, rules and regulations relating to air quality, water quality and usage, soil quality, emissions of greenhouse gases (GHG) such as carbon dioxide, waste management, hazardous wastes, fish, avian and other wildlife mortality and habitat protection, historical artifact preservation, natural resources, health, and safety. Compliance with such laws and regulations could, among other things, prevent or delay the development of power generation and transmission and distribution facilities, restrict output of facilities, limit the use of fuels required for power generation,

require additional pollution control equipment, require investment in non-emitting resources, and otherwise increase costs and increase capital expenditures. A portion of PGEs total system load is supplied with power generated from hydroelectric and wind generating resources. Operation of these facilities is subject to regulation related to the protection of fish and wildlife. Changes to the listing of various plants and species of fish, birds, and other wildlife as threatened or endangered could result in increased mitigation activities, which could have a material impact on PGEs financial condition and results of operations. Salmon recovery plans could include further major operational changes to the regions hydroelectric projects, including those owned by PGE and those from which the Company purchases power under long-term contracts. In addition, laws relating to the protection of migratory birds and other wildlife could impact the development and operation of transmission and distribution lines and wind projects. Also, new interpretations of existing laws and regulations could be adopted or become applicable to such facilities, which could further increase required expenditures for salmon recovery and endangered species protection and reduce the availability of hydroelectric or wind generating resources to meet the Companys energy requirements. Compliance with any new or additional GHG emissions reduction requirements could require PGE to incur significant expenditures, including those related to carbon capture and sequestration technology, purchase of emission allowances and offsets, fuel switching, and the retirement or replacement of high-emitting generation facilities with non-emitting facilities. The cost to comply with potential GHG emissions reduction requirements is subject to significant uncertainties, including those related to: the timing of the implementation of emissions reduction rules; required levels of emissions reductions; requirements with respect to the allocation of emissions allowances; the maturation, regulation, and commercialization of carbon capture, sequestration, and storage technology; and PGEs compliance alternatives. Although the Company cannot currently estimate the effect of future laws and regulations on its results of operations, financial condition, or cash flows, the costs of compliance with such legislation or regulations could be material. Changes in tax laws may have an adverse impact on the Companys financial position, results of operations, and cash flows. PGE makes judgments and interpretations about the application of tax law when determining the provision for taxes. Such judgments include the timing and probability of recognition of income, deductions, and tax credits, which are subject to challenge by taxing authorities. Additionally, treatment of tax benefits and costs for ratemaking purposes could be different than what the Company anticipates or requests from the State regulatory commission, which could have a negative effect on the Companys financial condition and results of operations. PGE owns and operates renewable generating facilities, which generate federal production tax credits (PTCs) that PGE uses to reduce its federal tax obligations. The amount of PTCs earned depends on the level of electricity output generated and the applicable tax credit rate. A variety of operating and economic parameters, including adverse weather conditions and equipment reliability, could significantly reduce the PTCs generated by the Companys wind facilities resulting

in a material adverse impact on PGEs financial condition and results of operations. These PTCs generate tax credit carryforwards that the Company plans to utilize in the future to reduce income tax obligations. If PGE cannot generate enough taxable income in the future to utilize all of the tax credit carryforwards before the credits expire, the Company may incur material charges to earnings. ECONOMIC, FINANCIAL, AND MARKET RISKS A decrease in customer demand for electricity may negatively impact PGEs business. Unfavorable economic conditions in Oregon, such as, for example, increased inflation, may result in reduced demand for electricity and impair the financial stability of PGEs customers. Such reductions in demand could adversely affect PGEs results of operations and cash flows. Economic conditions could also result in an increased level of uncollectible customer accounts and cause the Companys vendors and service providers to experience cash flow problems and be unable to perform under existing or future contracts. Customer demand could also be negatively impacted by PGEs ability to attract and retain customers, mandated energy efficiency measures, demand side management programs, potential formation of community choice aggregation programs, distributed generation resources, and economic and demographic conditions, such as population changes, job and income growth, new construction, new business formation and the overall level of economic activity. Development, improvement, and adoption of technological advances could lead to declines in energy use per customer. Some or all of these factors could impact the demand for electricity. The decline in revenues due to decreased customer demand for electricity may increase customer prices for remaining customers, as PGEs revenue requirement is designed to cover its fixed utility operating expenses. Increased customer prices could further reduce customer demand for electricity and strain PGEs ability to attract and retain customers. The loss of customers, the inability to replace those customers with new customers, and the decrease in demand for electricity could negatively impact PGEs financial condition and results of operations. Capital and credit market conditions could adversely affect the Companys access to capital, cost of capital, and ability to execute its strategic plan. Access to capital and credit markets is important to PGEs ability to operate. The Company expects to issue debt and equity securities, as necessary, to fund its future capital requirements. Volatility of interest rates could negatively impact PGEs cost of debt and results of operations. In addition, contractual commitments and regulatory requirements may limit the Companys ability to delay or terminate certain projects. If the capital and credit market conditions in the United States and other parts of the world deteriorate, the Companys future cost of debt and equity capital, as well as access to capital markets, could be adversely affected. In addition, sales or issuances of substantial amounts of PGEs common stock in the public market, including upon settlement of the forward sale agreements entered into in 2022, could cause the market price of PGEs common stock to decline. This could impair the Companys ability to raise additional capital through the sale of equity securities. Future sales or issuances of common stock or other equity-related securities could be dilutive to holders of common stock and could adversely affect their voting and other rights and

economic interests. PGE expects to raise additional capital in the future. PGE may raise additional funds through public or private equity or debt offerings or other financings, as well as additional borrowings under existing credit facilities. Any new debt financing entered into may involve covenants that restrict operations more than PGEs current outstanding debt and credit facilities. These restrictive covenants could include limitations on additional borrowings, specific restrictions on the use of assets, and prohibitions or limitations on the Companys ability to create liens, pay dividends, receive distributions from subsidiaries, redeem or repurchase stock or make investments. These factors could hinder the Companys access to capital markets and limit or delay the ability to carry out the Companys capital expenditure plan or pursue other opportunities beyond the current capital expenditure plan. The declaration of future dividends is at the discretion of the Board of Directors and is not guaranteed and, in some circumstances, the payment of dividends may be limited by the terms of PGEs debt instruments. PGE has historically paid regular quarterly dividends on common stock. However, the declaration of dividends is at the discretion of PGEs Board of Directors and is not guaranteed. The amount of common stock dividends, if any, will depend upon results of operations and financial condition, future capital expenditures and investments, the rights of holders of any outstanding shares of preferred stock, and other factors that the Board of Directors considers relevant. In addition, the terms of the Companys debt instruments may limit the payment of dividends. Under the Indenture of Mortgage and Deed of Trust, dated July 1, 1945, as amended and supplemented to date, between PGE and Wells Fargo Bank, National Association, so long as any of the first mortgage bonds are outstanding, the Company may not pay or declare dividends (other than stock dividends) on common stock or purchase or retire for a consideration (other than in exchange for other shares of PGEs capital stock or the proceeds from the sale of other shares of capital stock) any shares of capital stock of any class, if the aggregate amount distributed or expended after December 31, 1944 would exceed the aggregate amount of PGEs net income, as adjusted, available for dividends on common stock accumulated after December 31, 1944. At December 31, 2022, $399 million of accumulated net income was available for payment of dividends under this provision. Adverse changes in PGEs credit ratings could negatively affect its access to the capital markets and its cost of borrowed funds. Credit rating agencies routinely evaluate the Company, and their ratings of long-term and short-term debt are based on a number of factors, including the perceived supportiveness of the regulatory environment affecting the utility operations, the Companys cash generating capability, level of indebtedness, overall financial strength, the status of certain capital projects, as well as factors beyond PGEs control, such as tax reform, the state of the economy and industry generally. A ratings downgrade could increase fees on PGEs syndicated unsecured revolving credit facility, commercial paper program, and letter of credit facilities, increasing the cost of funding day-to-day working capital requirements, and could also result in higher interest rates on future long-term debt. A ratings downgrade could also restrict the Companys access to the commercial paper market, a principal source of short-term financing, or

result in higher interest costs. In addition, if Moodys Investors Service (Moodys) and/or SP Global Ratings (SP) reduce their rating on PGEs unsecured debt to below investment grade, the Company could be subject to requests by certain wholesale counterparties to post additional performance assurance collateral, which could have an adverse effect on the Companys liquidity and ability to participate in the wholesale markets. Under certain circumstances, banks participating in PGEs syndicated unsecured revolving credit facility could decline to fund advances requested by the Company or could withdraw from participation in the credit facility, which could adversely affect PGEs liquidity. PGE currently has a syndicated unsecured revolving credit facility with several banks for an aggregate amount of $650 million. The revolving credit facility provides a primary source of liquidity and may be used to supplement operating cash flow and as backup for commercial paper borrowings. The revolving credit facility represents commitments by the participating banks to make loans and, in certain cases, to issue letters of credit. The Company is required to make certain representations to the banks each time it requests an advance under the credit facility. However, in the event of a material adverse change in the business, financial condition, or results of operations of PGE, the Company may not be able to make such representations, in which case the banks would not be required to lend. PGE is also subject to the risk that one or more of the participating banks may default on their obligation to make loans under the credit facility. Adverse capital market performance could result in reductions in the fair value of benefit plan assets and increase the Companys liabilities related to such plans. Sustained declines in the fair value of the plans assets could result in significant increases in funding requirements, which could adversely affect PGEs liquidity and results of operations. Performance of the capital markets affects the value of assets that are held in trust to satisfy future obligations under PGEs defined benefit pension and other postretirement plans. Sustained adverse market performance could result in lower rates of return for these assets than projected by the Company and could increase PGEs funding requirements related to the plans. Additionally, changes in interest rates affect PGEs liabilities under the plans. As interest rates decrease, the Companys liabilities increase, potentially requiring additional funding. Performance of the capital markets also affects the fair value of assets that are held in trust to satisfy future obligations under the Companys non-qualified employee benefit plans, which include deferred compensation plans. As changes in the fair value of these assets are recorded in current earnings, decreases can adversely affect the Companys operating results. In addition, such decreases can require that PGE make additional payments to satisfy its obligations under these plans. The volatility of market prices for power and natural gas could adversely affect PGEs costs and ability to manage its energy supply, which could negatively impact the Companys liquidity and results of operations. As part of its normal business operations, PGE purchases and sells power and natural gas in the open market under short- and long-term contracts, which may specify variable prices or volumes. Market prices for power and natural gas are influenced primarily by factors related to supply and demand. These factors

generally include the adequacy of generating capacity, scheduled and unscheduled outages of generating facilities, hydroelectric and wind generation levels, prices and availability of fuel sources for generation, disruptions or constraints to transmission facilities, weather conditions, economic growth, and changes in technology. Volatility in these markets can affect the availability, price, and demand for power and natural gas. Disruption in power and natural gas markets could result in a deterioration of market liquidity, increase the risk of counterparty default, affect regulatory and legislative processes in unpredictable ways, affect wholesale power prices, and impair PGEs ability to manage its energy portfolio. Changes in power and natural gas prices can also affect the fair value of derivative instruments and cash requirements to purchase power and natural gas. If power and natural gas prices decrease from those contained in the Companys existing purchased power and natural gas agreements, PGE may be required to provide increased collateral, which could adversely affect the Companys liquidity. Conversely, if power and natural gas prices rise, especially during periods when the Company requires greater-than-expected volumes that must be purchased at market or short-term prices, PGE could incur greater costs than originally estimated. PGEs contract positions are not fully hedged against commodity prices, and hedges or other risk mitigations may not protect against significant losses. The risk of volatility in power costs is partially mitigated through the AUT and the PCAM. Application of the PCAM requires that PGE absorb certain power cost increases before the Company is allowed to recover any amount from customers. Accordingly, the PCAM is expected to only partially mitigate the potentially adverse financial impacts of forced generating plant outages, reduced hydro and wind availability, interruptions in fuel supplies, and volatile wholesale energy prices. PGE has put in place risk management policies, procedures, and controls to identify, quantify, and manage risk, however, these systems, processes, tools, and controls may not prevent material losses. Risk management procedures may not always be followed as intended, may not operate as designed, or may not identify all potential risks, including, without limitation, severe weather or employee misconduct. There is no assurance that PGEs risk management procedures will be effective in preventing or mitigating losses, and could have a material adverse effect on the Companys results of operation and financial condition. Reduced river flows, unfavorable wind conditions, and forced outages at generating and battery storage facilities can increase the cost of power required to serve customers. The Company could be required to replace energy expected from these sources with higher cost power from other facilities or with wholesale market purchases, which could have an adverse effect on results of operations. PGE derives a significant portion of its power supply from its own hydroelectric facilities and long-term purchase contracts with certain public utility districts in the state of Washington. Regional rainfall and snowpack levels affect river flows and the resulting amount of energy generated by these facilities. Shortfalls in energy expected from lower cost hydroelectric generating resources would require increased energy from the Companys other generating resources and/or power purchases in the wholesale market, which could have an adverse effect on results of

operations. PGE also derives a portion of its power supply from wind generating resources, for which the output is dependent upon wind conditions. Unfavorable wind conditions could require increased reliance on power from the Companys thermal generating resources or power purchases in the wholesale market, both of which could have an adverse effect on results of operations. Forced outages at generating facilities and battery storage facilities, both PGE-owned or under purchased power agreements, could result in power costs greater than those included in customer prices, in addition to increased repair and maintenance costs. Although the application of the PCAM could help mitigate adverse financial effects from any decrease in power supply, full recovery of any increase in power costs is not assured. Inability to fully recover such costs in future prices could have a negative impact on the Companys results of operations, as well as a reduction in renewable energy credits and loss of PTCs related to wind generating resources. The capacity provided by the Companys generating resources and third-party purchased power may not be sufficient to meet its customers energy demand requirements. PGE meets its customers energy demand requirements based on capacity obtained from its generating facilities and third-party power purchase agreements. The Company continuously evaluates how much capacity it will need to meet reasonably expected demands of customers and provide reasonable reserves. PGE is also required to file Integrated Resource Plans with the OPUC that detail the Companys plan to meet the future energy and capacity needs of its customers through a least-cost, least-risk combination of energy generation and demand reduction, while also aggressively reducing GHG emissions from the power supply. If the capacity provided by the Companys generating facilities and purchased power is not adequate to meet customers energy demands, PGE may be required to purchase more power from third parties, invest in acquiring additional generating or battery storage facilities, or invest in extending the operating life of existing generating assets. Any failure to obtain adequate capacity to meet customers energy demand requirements could increase its costs and negatively impact PGEs customer satisfaction, all of which could have an adverse impact on PGEs business and results of operations. Advances in energy technology could make PGEs business less competitive. A basic premise of PGEs business as a vertically integrated utility is the ability to produce electricity at competitive prices due to economies of scale. Furthermore, a key component of PGEs growth is its ability to construct, own, and operate facilities. Many companies and organizations conduct research and development activities to seek improvements in alternative technologies and distributed generation. Advancements in and creation of new technologies could include fuel cells and micro turbines, wind turbines, photovoltaic solar cells, distributed generation, nuclear energy, hydrogen, ongoing customer energy efficiency, two-way grid enabling customer-owned generation, and advances in batteries or energy storage. It is possible that advances in such technologies, or other current technologies, will reduce the cost of alternative methods of electricity production or storage to a level that is equal to or below that of existing methods. The electricity industry is undergoing significant change, including increased deployment of distributed

energy resources, technological advancements as described above, and political and regulatory developments. Electric utilities are experiencing increasing deployment of distributed energy resources, such as solar generation, energy storage, energy efficiency and demand response technologies. The deployment of these technologies supports PGEs decarbonization goals. The growth of new technologies will require modernization of the electric distribution grid to, among other things, accommodate increasing two-way flows of electricity and increase the grids capacity to interconnect these resources. A higher penetration of distributed energy resources may result in decreased customer demand, or may have impacts on grid reliability. Increased distributed energy resources and renewable energy resources will require new and sustained investments in grid modernization and transmission. If all such costs are not recoverable in rates, PGE could experience material increases in its commodity costs, which could impact PGEs results of operations, financial condition, or cash flows. It is also possible that alternative generation or storage resources are mandated, subsidized, or encouraged through legislation or regulation or otherwise are economically competitive and added to the available generation supply. Competitors may not be subject to the same operating, regulatory and financial requirements that the Company is, potentially causing a substantial competitive disadvantage for PGE. Changes in public policy, such as new tax incentives that PGE cannot take advantage of or efforts to deregulate the utility industry, could provide an advantage to competitors. Such alternative resources and regulatory or legislative actions could displace higher marginal cost generating units or make PGE less competitive in constructing, owning, and operating such facilities. Such a development could limit the Companys future growth opportunities and limit growth in demand for PGEs electric service. Changes in market conditions and environmental laws and regulations could negatively impact PGEs non-utility real estate investments. PGE owns, through a wholly owned subsidiary, its corporate headquarters building located in Portland, Oregon. A significant change in real estate values could adversely affect PGEs results of operations. PGE also owns unregulated properties that are currently or previously leased to third parties and located adjacent to PGEs T.W. Sullivan hydro generating facility. PGE has recorded a non-utility asset retirement obligation (ARO) for this site related to assets that are no longer in service. Significant changes in estimates for this non-utility ARO due to changes in environmental laws or regulations could adversely affect PGEs results of operations. Rapidly changing stakeholder expectations and standards with respect to PGEs environmental, social, and governance (ESG) programs could result in increased costs and exposure to incremental risk. Investors, lenders, rating agencies, customers, regulators, employees, and other stakeholders are increasing their focus on evaluating companies as corporate citizens based on their ESG programs and metrics. Based on PGEs ESG profile, investors and lenders may elect to increase their required returns on capital offered to the Company, reallocate capital, or not commit capital as a result of their assessment of the Companys ESG profile. Such actions by investors and lenders could increase PGEs cost of, or access to, capital and financing. PGE is

committed to the success of its ESG programs; however, if the Company fails to adapt or execute on its ESG strategies, or is perceived to have failed in addressing stakeholder ESG expectations or standards, which continue to evolve, PGE may suffer reputational damage, which could have a material adverse effect on its business, results of operations, and financial condition. Additionally, the cost of implementing and complying with such ESG programs could be material. Actions of activist shareholders could have a negative impact on PGEs business. Actions of activist shareholders, which can take many forms and arise in a variety of situations, could include engaging in proxy solicitations, advancing shareholder proposals, or otherwise attempting to effect changes and assert influence on the Companys board of directors and management. Dealing with such actions could result in substantial costs and divert managements and the Companys boards attention and resources from PGEs business and execution of its strategy. Such shareholder activism could give rise to perceived uncertainties regarding PGEs future, adversely affecting PGEs business opportunities, ability to access capital markets, relationships with its customers and employees, and make it more difficult to attract and retain a qualified workforce. Any such actions could have a material adverse effect on the Companys financial condition and results of operations and could cause significant fluctuations in the trading prices of its common stock based on market perceptions or other factors. PGEs business activities are concentrated in one region and future performance may be affected by events and factors unique to Oregon or the region. The Companys industry and geographic concentrations may increase exposure to risks arising from regional regulation or legislation, such as legislative action related to carbon emissions. These concentrations may also increase exposure to credit and operational risks due to counterparties, suppliers, and customers being similarly affected by changing conditions.

Ticker: POR, Sector: Utilities, Filed At: 2023-02-15T19:18:09-05:00

ITEM 1. BUSINESS. General Portland General Electric Company (PGE or the Company), a vertically-integrated electric utility with corporate headquarters located in Portland, Oregon, is engaged in the generation, wholesale purchase, transmission, distribution, and retail sale of electricity in the state of Oregon (State). The Company operates as a cost-based, regulated electric utility with revenue requirements and customer prices determined based on the forecasted cost to serve retail customers and a reasonable rate of return as determined by the Public Utility Commission of Oregon (OPUC). PGE meets its retail load requirement with both Company-owned generation and power purchased in the wholesale market. The Company participates in the wholesale market through the purchase and sale of electricity and natural gas in an effort to obtain reasonably-priced power to serve its retail customers. PGE is committed to developing products and service offerings for the benefit of retail and wholesale customers. PGE, incorporated in 1930, is publicly-owned, with its common stock listed on the New York Stock Exchange (NYSE). The Company operates as a single business segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis. The Company owns unregulated, non-utility real estate comprised primarily of PGEs corporate headquarters. PGEs State-approved service area allocation of four thousand square miles is located entirely within Oregon and includes 51 incorporated cities. During 2022, the Company added nine thousand customers, and as of December 31, 2022, served a total of 926 thousand retail customers. Available Information PGEs periodic and current reports, and amendments to those reports, are available and may be accessed free of charge through the Investors section of the Companys website at PortlandGeneral.com as soon as reasonably practicable after the reports are electronically filed with, or furnished to, the United States Securities and Exchange Commission (SEC). It is not intended that PGEs website and the information contained therein or connected thereto be incorporated into this Annual Report on Form 10-K. Regulation Federal and State regulation each have a significant influence on PGEs business operations. In addition to the agencies and activities discussed below, the Company is subject to regulation by certain environmental agencies, as described in the Environmental Matters section in this Item 1. Federal Regulation Several federal agencies, including the Federal Energy Regulatory Commission (FERC), the U.S. Department of Transportations Pipeline and Hazardous Materials Safety Administration (PHMSA), and the Nuclear Regulatory Commission (NRC), have regulatory authority over certain of PGEs operations and activities, as described in the discussion that follows. PGE is a licensee, a public utility, and a user, owner, and operator of the bulk power system, as those terms are defined in the Federal Power Act (FPA). As such, the Company is subject to regulation by the FERC in matters related to wholesale energy activities, transmission services, reliability and cybersecurity standards, natural gas pipelines, hydroelectric projects, accounting policies and practices, short-term debt issuances, and certain other matters. Wholesale Energy PGE has authority under its FERC Market-Based Rates tariff to charge market-based rates for wholesale energy sales in all markets in which it sells electricity except in its own Balancing Authority Area (BAA). The BAA is the area in which PGE is responsible for balancing customer demand with electricity supply, in real time, and the tariff exception within PGEs BAA does not have a material impact on the Company. Transmission PGE offers wholesale electricity transmission service pursuant to its Open Access Transmission Tariff (OATT), which contains rates, terms, and conditions of service, as filed with, and approved by, the FERC. Reliability and Cybersecurity Standards The FERC has adopted mandatory reliability standards for owners, users, and operators of the bulk power system. Such standards, which are applicable to PGE, were developed by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC), which have responsibility for compliance and enforcement of these standards, and are intended to help protect critical cyber and physical assets used to support reliable operations. Natural Gas Pipelines The FERC has authority in matters related to the construction, operation, extension, enlargement, safety, and abandonment of jurisdictional interstate natural gas pipeline facilities, as well as transportation rates and accounting for interstate natural gas commerce. PGE is subject to such authority as the Company has a 79.5% ownership interest in the Kelso-Beaver (KB) Pipeline, a 17-mile, 20-inch diameter, interstate pipeline that provides natural gas to

Port Westward Unit 1 (PW1), Port Westward Unit 2 (PW2), and Beaver, the Companys natural gas-fired generating plants located near Clatskanie, Oregon, to the North Mist storage facility (owned and operated by a local natural gas distribution company), and to one additional local delivery point that serves a manufacturing concern. As the operator of record of the KB Pipeline, PGE is subject to the requirements and regulations enacted under the Pipeline Safety Laws administered by the PHMSA, which include safety and operator qualification standards in addition to public awareness requirements. Hydroelectric Licensing As required under the FPA, PGE holds FERC licenses for all Company-owned and operated hydroelectric generating plants. The FERC license process includes an extensive public review process that involves the consideration of numerous natural resource issues and environmental conditions. For additional information, see the Environmental Matters section in this Item 1. and the Generating Facilities section in Item 2.Properties. Accounting Policies and Practices PGE prepares periodic and current reports in accordance with accounting principles generally accepted in the United States of America (GAAP). In addition, the Company prepares, pursuant to applicable provisions of the FPA, financial statements in accordance with the accounting requirements of the FERC, as set forth in its applicable Uniform System of Accounts and published accounting releases. Such financial statements are included in annual and quarterly reports filed with the FERC. Short-term Debt Pursuant to applicable provisions of the FPA and FERC regulations, regulated public utilities are required to obtain FERC approval to issue certain securities. For additional information on the Companys Short-term Debt, see Short-term Debt in the Debt and Equity section of Liquidity and Capital Resources in Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Spent Fuel Storage The NRC regulates the licensing and decommissioning of nuclear power plants, including PGEs decommissioned Trojan nuclear power plant (Trojan), which was closed in 1993. For additional information on spent nuclear fuel storage activities, see Note 8, Asset Retirement Obligations in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data and Hazardous Material in the Environmental Matters section of this Item 1. State Regulation PGE is subject to the jurisdiction of the OPUC, which reviews and approves the Companys retail prices and reviews the Companys generation and transmission resource acquisition plans, pursuant to a biennial integrated resource planning process. The OPUC regulates the issuance of securities, prescribes accounting policies and practices, regulates the sale of utility assets, reviews transactions with affiliated companies, and has jurisdiction over the acquisition of, or exertion of substantial influence over, public utilities. Retail customer prices are determined through formal public proceedings that generally include testimony by participating parties, discovery, public hearings, and the issuance of a final order by the OPUC. Participants in such proceedings may include PGE, OPUC staff, and intervenors representing PGE customer groups, as well as other interested parties. The following lists the more significant regulatory mechanisms and proceedings under which customer prices are determined: General Rate Cases . PGE periodically

evaluates the need to update its retail electric price structure as part of a comprehensive general rate case process that reflects revenue requirements based on a forecasted test year. The OPUC authorizes the Companys debt-to-equity capital structure, return on equity, overall rate of return, and customer prices. Annual Power Cost Updates . The OPUC has approved an Annual Power Cost Update Tariff (AUT) by which PGE can adjust retail customer prices annually to reflect forecasted changes in the Companys net variable power costs (NVPC). NVPC consists of the cost of power purchased and fuel used to generate electricity, as well as the cost of settled electric and natural gas financial contracts (all classified as Purchased power and fuel expense in the Companys consolidated statements of income) and is net of wholesale revenues, which are classified in the consolidated statements of income as Revenues, net. The OPUC has also authorized a Power Cost Adjustment Mechanism (PCAM), under which PGE may share with customers a portion of actual cost variances associated with NVPC. Renewable Energy. The State has a Renewable Portfolio Standard (RPS) that requires PGE to serve a portion of its retail load with renewable resources. In conjunction with the RPS, the State established a Renewable Adjustment Clause (RAC) mechanism that allows for the recovery in retail customer prices, outside of a general rate case, of prudently incurred costs to comply with the RPS. In 2016, the State also passed Oregon Senate Bill (SB) 1547, a law referred to as the Oregon Clean Electricity and Coal Transition Plan, which, among its provisions, increased the RPS percentages in certain future years and required the elimination of coal from Oregon utility customers energy supply. For further information on SB 1547, see RPS standards and other laws in the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. During 2021, the State legislature passed House Bill (HB) 2021, which establishes clean energy targets and sets out a framework that includes, among other things, the development and submittal of clean energy plans for investor-owned utilities, including PGE, and electric service suppliers in the State. The targets are an 80% reduction in greenhouse gas (GHG) emissions by 2030, 90% by 2035, and 100% by 2040 and every year thereafter. For further information on HB 2021 and the baseline to which the target reductions apply, see HB 2021 in the Laws and Regulations portion of the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Regulatory Accounting PGE prepares financial statements in accordance with GAAP and, as a regulated public utility, the effects of rate regulation are reflected in its financial statements. GAAP provides for the deferral, as regulatory assets, of certain actual or estimated costs that would otherwise be charged to expense, based on expected recovery from customers in future prices. Likewise, certain actual or anticipated credits that would otherwise be recognized as revenue or reduce expense can be deferred as regulatory liabilities, based on expected future credits or refunds to customers. PGE records regulatory assets or liabilities if it is probable that they will be reflected in future prices, based on regulatory orders or other available evidence. The Company periodically assesses the applicability of regulatory accounting to its business, considering both the current and

anticipated future regulatory environment and related accounting guidance . For additional information, see Regulatory Assets and Liabilities in Note 2, Summary of Significant Accounting Policies, and Note 7, Regulatory Assets and Liabilities, in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data. Customers and Revenues PGE generates revenue primarily through the sale and delivery of electricity to retail customers located exclusively in Oregon. In addition, the Company distributes power to customers that choose to purchase their energy from an Electricity Service Supplier (ESS). Although the Company includes such Direct Access customers in its customer counts and energy delivered to such commercial and industrial customers in its total retail energy deliveries, retail revenues include only delivery charges and applicable transition adjustments for these Direct Access customers, as the customers purchase energy directly from the ESSs. The Company conducts retail electric operations within its State-approved service territory and competes with ESSs to supply certain commercial and industrial customer energy needs. In addition, PGE competes with the local natural gas distribution company for the energy needs of residential and commercial space heating, water heating, and appliances. Energy efficiency, conservation measures, and the advancement of distributed generation, including rooftop solar, and storage resources also have an influence on customer demand. Retail Revenues Retail customers are classified as residential, commercial, or industrial, with no single customer representing more than 8% of PGEs total retail revenues or 13% of total retail deliveries. PGEs Retail revenues, retail energy deliveries, and average number of retail customers consist of the following: ##TABLE_START Years Ended December 31, 2022 2021 2020 Retail revenues (1) (dollars in millions): Residential $ 1,158 52 % $ 1,118 54 % $ 1,030 53 % Commercial 735 33 708 34 634 33 Industrial 312 14 279 13 246 13 Subtotal 2,205 99 2,105 101 1,910 99 Alternative revenue programs, net of amortization 11 1 (29) (1) (6) Other accrued revenues, net (2) 7 2 28 1 Total retail revenues $ 2,223 100 % $ 2,078 100 % $ 1,932 100 % Retail energy deliveries (3) (MWh in thousands): Residential 8,088 38 % 7,978 39 % 7,756 40 % Commercial 7,198 34 7,193 35 6,855 35 Industrial 5,945 28 5,361 26 4,932 25 Total retail energy deliveries 21,231 100 % 20,532 100 % 19,543 100 % Average number of retail customers: Residential 809,573 88 % 800,372 88 % 791,119 88 % Commercial 112,602 12 111,569 12 110,851 12 Industrial 269 268 267 Total 922,444 100 % 912,209 100 % 902,237 100 % ##TABLE_END##TABLE_START ##TABLE_END(1) Includes both revenues from customers who purchase their energy supplies from the Company and revenues from the delivery of energy to those commercial and industrial customers that purchase their energy from ESSs. (2) Amount for the year ended December 31, 2020 is primarily comprised of $24 million of amortization, including interest, related to the deferral recorded in 2018 for the net tax benefits due to the change in corporate tax rate under the United States Tax Cuts and Jobs Act of 2017 (TCJA). (3) Includes both energy sold to retail customers and energy deliveries to those commercial and industrial customers that purchase their energy from ESSs. The following table presents additional annual

averages for retail customers. Certain supplemental tariff collections are excluded from revenues as they are not considered a part of the Companys base retail prices for these calculations. ##TABLE_START Years Ended December 31, 2022 2021 2020 Residential Revenue per customer (in dollars): $ 1,362 $ 1,320 $ 1,226 Usage per customer (in kilowatt hours): 9,991 9,968 9,804 Revenue per kilowatt hour (in cents): 13.63 13.24 12.50 Commercial Revenue per customer (in dollars): $ 6,491 $ 6,303 $ 5,684 Usage per customer (in kilowatt hours): 63,923 64,478 61,837 Revenue per kilowatt hour (in cents): 10.15 9.78 9.19 Industrial Revenue per customer (in dollars): $ 1,156,371 $ 1,044,314 $ 921,540 Usage per customer (in kilowatt hours): 22,097,472 20,002,246 18,472,161 Revenue per kilowatt hour (in cents): 5.23 5.22 4.99 ##TABLE_ENDFor additional information, see the Results of Operations section in Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. In addition to standard cost-of-service pricing, the Company offers different pricing options including a daily market price option, various time-of-use options, and several renewable energy options. For additional information on customer options, see Customer Choice Programs within this Customers and Revenues section of this Item 1. Residential customers include single family housing, multiple family housing (such as apartments, duplexes, and town homes), mobile homes, and small farms. Residential demand is sensitive to the effects of weather. The Company had seen its highest peak demand during the winter heating season although increased use of air conditioning in PGEs service territory has caused the summer peaks to increase over time. In recent years, including 2022, summer peaks have exceeded winter peaks and long-term load forecasts expect that trend to continue. An extreme winter temperature event on December 22, 2022, caused a new winter peak for the first time since 1998. Economic conditions can also affect residential demand as job growth and population growth in PGEs service territory have led to increased customer growth rates. The COVID-19 pandemic has introduced additional behavioral patterns as residential customers spend more time at home. Residential demand is also impacted by energy efficiency measures and increased rooftop solar penetration in the service territory; however, the Companys decoupling mechanism was intended to mitigate the financial effects of such measures. For further information regarding the decoupling mechanism, see Decoupling among the Regulatory Matters in the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Commercial customers consist of non-residential customers who accept energy deliveries at voltages equivalent to those delivered to residential customers. This customer class includes most businesses, small industrial companies, and public street and highway lighting accounts. The Companys commercial customer demand is somewhat less susceptible to weather conditions than residential customer demand. Economic conditions and fluctuations in total employment in the region can lead to changes in energy demand from commercial customers. Energy efficiency measures also impact commercial demand, as measures have focused in the commercial sector in recent years, although the Companys decoupling mechanism was intended to partially mitigate the financial

effects of such measures. For further information regarding the decoupling mechanism, see Decoupling among the Regulatory Matters in the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Industrial customers consist of non-residential customers who accept delivery at higher voltages than commercial customers, with pricing based on the amount of electricity delivered under the applicable tariff. Demand from industrial customers is primarily driven by economic conditions, with weather having little impact on this customer class. Customer Choice Programs Under cost-of-service pricing, residential and small commercial customers may select portfolio options from PGE that include time-of-use and renewable resource pricing. Pricing options other than cost-of-service are available to certain commercial and industrial customers for a one-year period, including daily market index-based pricing under which the Company provides the electricity, and Direct Access, whereby customers purchase electricity directly from an ESS. PGE receives revenue from Direct Access customers only for the transmission and delivery of the volume of electricity delivered, along with fixed transition adjustments intended to mitigate the shifting of excess charges to the Companys cost-of-service customers. Certain large commercial and industrial customers may elect a fixed three-year or a minimum five-year term, to be served either by an ESS, or by the Company under the daily market index-based price option. Participation in the fixed three-year and minimum five-year opt-out programs for existing and planned load is capped at 300 average megawatts (MWa) in aggregate. In 2020, the OPUC issued an order that required PGE to begin offering, to eligible customers, enrollment in the New Large Load Direct Access program, which is capped at 119 MWa in total, for unplanned, large, new loads and large load growth at existing sites. For further information regarding Direct Access deliveries, see Customers and demand in the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. PGEs customers have a desire for purchasing clean energy, as over 234 thousand residential and small commercial customers voluntarily participate in PGEs Green Future Program, the largest renewable power program by participation in the nation. Oregons most populous city, Portland, and most populous county, Multnomah, have each passed resolutions to achieve 100 percent clean and renewable electricity by 2035 and 100 percent economy-wide clean and renewable energy by 2050. Other jurisdictions in PGEs service area have set, or are considering, similar goals. The Company implemented a new customer service option, the Green Future Impact Program, which allows for 100 MW of PGE-provided power purchase agreements for renewable resources and up to 200 MW of customer-provided renewable resources. Approved by the OPUC in 2019, the program provides business customers access to bundled renewable attributes from those resources. In March 2021, the OPUC issued an order that expanded the program by 200 MW and provided for the possibility of PGE ownership of the underlying renewable resources under certain conditions. Through this voluntary program, the Company seeks to align sustainability goals, cost and risk management, and reliable integrated power while

providing customer choice and a cleaner energy system. In December 2021, the OPUC issued an order, which approved a petition to increase capacity under the customer-provided renewable resources by 250 MW, which brings the total available capacity under the program to 750 MW. For more information on the Companys power purchase agreements that currently serve the Green Future Impact Program, see Green Future Impact Program within Purchased Power in the Power Supply section of this Item 1. Wholesale Revenues PGE participates in the wholesale electricity marketplace in order to balance its supply of power to meet the needs of its retail customers. Interconnected transmission systems in the western United States serve utilities with diverse load requirements and allow the Company to purchase and sell electricity, largely through bi-lateral agreements, within the region to serve retail demand. PGEs engagement in the wholesale electricity marketplace depends upon numerous factors, including the relative price and availability of power, hydro and wind conditions, and daily and seasonal retail demand. The Company also participates in the California Independent System Operators western Energy Imbalance Market (western EIM), which allows for load balancing with other western EIM participants in five-minute intervals. Wholesale revenues represented 14% of total revenues in 2022, 11% in 2021, and 8% in 2020. Other Operating Revenues Other operating revenues consist primarily of gains and losses on the sale of natural gas volumes purchased that exceeded what was needed to fuel the Companys generating facilities, as well as revenues from transmission services, excess transmission capacity resales, pole attachment rentals, and other electric services provided to customers. Other operating revenues represented 2% of total revenues in 2022, 3% in 2021, and 2% in 2020. Seasonality Demand for electricity by PGEs residential and, to a lesser extent, commercial customers is affected by seasonal weather conditions. The Company uses heating and cooling degree-days to determine the effect of weather on the demand for electricity. Heating and cooling degree-days, determined by taking the difference between the average daily temperature and a baseline of 65 degrees, provide cumulative variances over a period of time, to indicate the extent to which customers are likely to have used electricity for heating or cooling. The higher the number of degree-days, the greater the expected demand for electricity. The following table presents the heating and cooling degree-days for the most recent three-year period, along with current 15-year averages for the most recent year provided by the National Weather Service, as measured at Portland International Airport: ##TABLE_START Heating Degree-Days Cooling Degree-Days 2022 4,103 865 2021 3,828 838 2020 3,836 600 15-year average 4,103 569 ##TABLE_ENDIn June 2021, PGE set a new all-time high net system load peak of 4,453 megawatts (MW), surpassing the previous all-time peak that occurred in December 1998 by more than 9%. While the Companys previous summer peak of 3,976 MW had occurred in August 2017, that level has been exceeded now in each of the past two summers. In December 2022, a new winter peak of 4,113 MW occurred. The following table presents PGEs average winter (defined as January, February, and December) and summer (defined as June through September) loads for the periods

presented, along with the corresponding peak load (in MWs) and month in which such peak occurred. As illustrated, although the average winter loads continue to exceed average summer loads, the Company has seen its highest annual peak loads during the summer months in recent years: ##TABLE_START Winter Loads Summer Loads Average Peak Month Average Peak Month 2022 2,773 4,113 December 2,529 4,255 July 2021 2,659 3,629 December 2,492 4,453 June 2020 2,566 3,367 December 2,289 3,771 July ##TABLE_ENDThe Company tracks and evaluates both load growth and peak load requirements for purposes of long-term load forecasting, integrated resource planning, and preparing general rate case assumptions. Behavior patterns, conservation, energy efficiency initiatives and measures, weather effects, economic conditions, distributed generation including rooftop solar, transportation and building electrification, and demographic changes all play a role in determining expected future customer demand and the resulting resources the Company may need to adequately meet those loads and maintain adequate capacity reserves. Power Supply PGE utilizes its generating resources, as well as wholesale power purchases from third parties to meet the needs of its retail customers. The volume of electricity the Company generates is dependent upon, among other factors, the capacity and availability of its generating resources and the price and availability of wholesale power and natural gas. As part of its power supply operations, the Company enters into short- and long-term power and fuel purchase and sale agreements. PGE executes economic dispatch decisions concerning its own generation and participates in the wholesale market in an effort to obtain reasonably-priced power for its retail customers, manage risk, and administer its long-term wholesale contracts. The Company also performs portfolio management and wholesale market sales services for third parties in the region. The Company also encourages energy efficiency measures to help meet its energy requirements and promotes the use of various demand side management products to reduce load during peak time usage. PGEs resource and contracted capacity (in MW) was as follows: ##TABLE_START As of December 31, 2022 2021 Capacity % Capacity % Generation: Thermal (1) : Natural gas 1,842 32 % 1,842 35 % Coal 296 4 296 5 Total thermal 2,138 37 2,138 40 Wind (2) 817 15 817 16 Hydro (3) 419 7 495 9 Total generation 3,374 59 3,450 65 Purchased power: Long-term contracts: Hydro (3) 871 15 803 15 PURPA qualifying facilities (4) 315 5 298 6 Dispatchable standby generation 130 2 130 2 Capacity 100 2 100 2 Wind (2) 300 5 300 6 Solar (5) 57 1 7 Biomass 10 10 Total long-term contracts 1,783 31 1,648 31 Short-term contracts 597 10 216 4 Total purchased power capacity 2,380 41 1,864 35 Total resource capacity 5,754 100 % 5,314 100 % ##TABLE_END##TABLE_START ##TABLE_END(1) Capacity represents the MW the plants are capable of generating under normal operating conditions, which is affected by ambient temperatures, net of electricity used in the operation of the plant. (2) Capacity represents nameplate and differs from expected energy to be generated, which is expected to have a capacity factor range from 30 to 40%, dependent upon wind conditions. (3) Capacity represents net capacity and differs from expected energy to be generated, which is expected to have a capacity factor range from 40 to 50%,

dependent upon river flows. (4) Capacity represents contracted capacity for power purchase agreements (PPAs) under the Public Utility Regulatory Policies Act of 1978 (PURPA). (5) Capacity includes 50 MW from the solar component of Wheatridge. The Wheatridge facility also includes 30 MW related to the battery component which is not reflected in the table above. For information regarding actual generating output and purchases for the years ended December 31, 2022 and 2021, see the Results of Operations section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Generation PGEs generating resources consist of six thermal plants (natural gas- and coal-fired), three wind farms, and seven hydroelectric facilities. The portion of PGEs retail load requirements generated by its plants varies from year to year and is determined by various factors, including planned and unplanned outages, availability and price of coal and natural gas, precipitation and snow-pack levels, the market price of electricity, and wind variability. For a complete listing of these facilities, see Generating Facilities in Item 2.Properties. Thermal The Company has five natural gas-fired generating facilities: PW1, PW2, Beaver, Coyote Springs Unit 1 (Coyote Springs), and Carty Generating Station (Carty). The Company operated, and continues to have a 90% ownership interest in the Boardman coal-fired generating plant (Boardman), which ceased coal-fired operations during the fourth quarter of 2020. The Company has begun decommissioning the facility. The Company also has a 20% ownership interest in the Colstrip Units 3 and 4 coal-fired generating plant (Colstrip), which is located in Colstrip, Montana and operated by a third party. For additional information on Colstrip as it relates to environmental laws and regulations in the State, see RPS standards and other laws in the Overview section in Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations and Note 19, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data. Wind PGE owns and operates two wind farms, Biglow Canyon Wind Farm (Biglow Canyon) and Tucannon River Wind Farm (Tucannon River). Biglow Canyon, located in Sherman County, Oregon, consists of 217 turbines with a total nameplate capacity of 450 MW. Tucannon River, located in southeastern Washington, consists of 116 turbines with a total nameplate capacity of 267 MW. During 2020, the wind component of the Wheatridge Renewable Energy Facility (Wheatridge), located in Morrow County, Oregon, was placed into service. Although PGE does not operate Wheatridge, it owns 40 turbines with a total nameplate capacity of 100 MW and purchases the output of the remaining turbines, with a nameplate capacity of 200 MW through power purchase agreement. PGE and NextEra Energy Resources, LLC, a subsidiary of NextEra Energy, Inc. have entered into agreements to construct a 311 MW wind energy facility, which will be part of the larger Clearwater Wind development in Eastern Montana. This additional wind capacity is not reflected in the table above. For more information regarding the Clearwater Wind development, see The Resource Planning Process within the Overview section of Item 7 Managements Discussion and Analysis of Financial Condition and Results of Operations. Hydro The Companys FERC-licensed

hydroelectric projects consist of Pelton/Round Butte on the Deschutes River near Madras, Oregon (discussed below), four plants on the Clackamas River, and one on the Willamette River. As of December 31, 2021, PGE had a 66.67% ownership interest in the 455 MW Pelton/Round Butte hydroelectric project on the Deschutes River, with the remaining interest held by the Confederated Tribes of the Warm Springs Reservation of Oregon (CTWS). A 50-year joint license for the project, which is operated by PGE, was issued by the FERC in 2005. The CTWS had an option to purchase an additional undivided 16.66% ownership interest in Pelton/Round Butte in 2021, and closed on the purchase of this incremental undivided ownership interest on January 1, 2022. As a result, PGEs ownership interest in the project is 50.01%. CTWS has a second option in 2036 to purchase an undivided 0.02% interest in Pelton/Round Butte. If the second option is exercised, CTWSs ownership percentage would exceed 50%. PGE purchases 100% of the CTWSs share of the project output. For more information see CTWS within Purchased Power in the Power Supply section of this Item 1. Fuel Supply PGE contracts for natural gas and coal supplies required to fuel the Companys thermal generating plants, with certain plants also able to operate on fuel oil, if needed. In addition, the Company uses forward, future, swap, and option contracts to manage its exposure to volatility in natural gas prices. Natural Gas Physical supplies of natural gas are generally purchased up to twelve months in advance of delivery and based on anticipated operation of the plants. PGE manages the price risk of natural gas supply through the use of financial contracts up to 60 months in advance of expected need of energy. PGE owns 79.5%, and is the operator of record, of the KB Pipeline, which directly connects PW1, PW2, and Beaver to the Northwest Pipeline, an interstate natural gas pipeline operating between British Columbia and New Mexico. Currently, PGE transports natural gas on the KB Pipeline for its own use under a firm transportation service agreement, with capacity offered to others on an interruptible basis to the extent not utilized by the Company. PGE has access to 111,805 Dth per day of firm natural gas transportation capacity on the Northwest Pipeline to serve the three plants. PGE has access to 4.1 billion cubic feet of natural gas storage in Mist, Oregon from which it can draw when economic factors favor its use or in the event that natural gas supplies are interrupted. The storage facility, owned and operated by NW Natural, may be utilized to provide fuel to PW1, PW2, and Beaver. To serve Coyote Springs and Carty, PGE has access to 120,000 Dth per day of firm natural gas transportation capacity on three pipeline systems accessing gas fields in Alberta, Canada. Coal The Colstrip co-owners obtain coal to fuel the plant via conveyor belt from a mine that lies adjacent to the facility and is the sole source of coal supply for the plant. The coal supply contract with the owner of the mine is scheduled to expire at the end of 2025. The terms of the contract and the quality of coal are expected to allow the facility to operate within required emissions limits. Purchased Power PGE supplements its own generation with power purchased in the wholesale market to meet its retail load requirements. The Company utilizes short- and long-term wholesale power purchase contracts in an effort to provide the most favorable economic mix on a variable cost

basis. PGEs medium-term power cost strategy helps mitigate the effect of price volatility on its customers due to changing energy market conditions. The strategy allows the Company to take positions in power and fuel markets up to five years in advance of physical delivery. By purchasing a portion of anticipated energy needs for future years over an extended period, PGE mitigates a portion of the potential future volatility in the average cost of purchased power and fuel. The Companys major power purchase contracts consist of the following (also see the preceding table which summarizes the average resource capabilities related to these contracts): Hydro During 2022, the Company had the following agreements: Public Utility Districts PGE has long-term power purchase contracts with certain public utility districts (PUDs) in the state of Washington for a portion of the output of two hydroelectric projects on the mid-Columbia River. Although the projects currently provide PGE a total of 410 MW of capacity through contracts as shown below, actual energy received is dependent upon river flows and capacity amounts may decline over time: 162 MW of capacity with Grant County PUD that expires in 2052; 148 MW of capacity with Douglas County PUD that expires in 2028; and 100 MW of capacity with Douglas County PUD that expires in 2025. CTWS PGE has a long-term agreement under which the Company purchases output from CTWS interest in the Pelton/Round Butte hydroelectric project. Although the agreement provides approximately 224 MW of net capacity, actual energy received is dependent upon river flows. The term of the agreement coincides with the term of the FERC license for this project, which expires in 2055. Under a separate PPA executed in 2014, PGE pays fixed capacity and energy charges to CTWS for 100% of its share of the project through 2024. On June 30, 2021 the CTWS notified PGE of their intent to exercise their option to purchase an additional undivided 16.66% ownership interest in Pelton/Round Butte and closed on the purchase on January 1, 2022. As a result of the sale, capacity from company-owned generation decreased by approximately 76 MW, and capacity from purchased power increased by a corresponding amount. Under the PPA, PGE purchases 100% of the CTWSs additional share of the project and payments under the PPA increase proportionately. In the fourth quarter of 2021, PGE and CTWS executed an additional 16-year PPA which begins on January 1, 2025, that effectively extends the term from 2024 to 2040 and increases the capacity payments in the extension period. Other The remaining capacity is primarily comprised of two additional contracts that provide for the purchase of power generated from hydroelectric projects with capacity of 236 MW in total: 200 MW of capacity with Bonneville Power Administration that expires in 2024; and 36 MW of capacity with Portland Hydro that expires in 2032 PURPA qualifying facilities PGE is required to purchase power from PURPA qualifying facilities (QFs), as mandated by federal law. QFs are generating facilities that fall within the following two categories: i) qualifying generation facilities with a capacity of 80 MW or less and whose primary energy source is renewable (hydro, wind, solar, biomass, waste, or geothermal); or ii) qualifying cogeneration facilities that sequentially produce electricity and another form of useful thermal energy (e.g., heat, steam) in a way that is more efficient than the separate production of each form of

energy. As of December 31, 2022, PGE had contracts with 67 online QFs, providing a total of 315 MW of capacity. As of December 31, 2022, PGE has six contracts with QFs representing 127 MW of capacity that are not yet operational, of which two of the QF PPAs are in default because the QF has failed to complete construction and become operational by the date required by the PPA. The PPAs provide that the QF has one year to cure its default. If the QF has failed to cure, PGE is permitted to immediately terminate the QF PPA upon expiration of the cure period. The term of a QF PPA generally ranges from 15 to 23 years. The expense and volume of purchases from QFs for the years ended December 31, 2022 and 2021 were as follows: ##TABLE_START 2022 2021 PURPA contract expense (in millions) $ 62 $ 55 MWh purchased under PURPA contracts (in thousands) 750 683 Average cost per MWh from PURPA contracts $ 82.90 $ 79.89 ##TABLE_ENDExpenses incurred related to PURPA contracts are included in PGEs AUT. Dispatchable Standby Generation (DSG) PGE has a DSG program under which the Company can start, operate, and monitor customer-owned backup generators when needed to provide NERC-required operating reserves. As of December 31, 2022, there were 59 customer-owned sites with a total DSG capacity of 130 MW. PGE continues to pursue expansion of the program with the goal of having an additional 3 to 10 MW of customer-owned DSG projects online by the end of 2023. Capacity PGE has one capacity contract representing up to 100 MW of seasonal capacity during the summer and winter peak periods obtained from a natural gas-fired resource, which expires in 2024. Wind PGE has three contracts representing 300 MW of capacity to purchase power generated from renewable wind resources that extend to 2028, 2035, and 2051. The expected energy from these wind resources will vary from the nameplate capacity due to varying wind conditions. PGE and NextEra Energy Resources, LLC, a subsidiary of NextEra Energy, Inc. have entered into agreements to construct a 311 MW wind energy facility, which will be part of the larger Clearwater Wind development in Eastern Montana. This additional wind capacity is not reflected in the table above. For more information regarding the Clearwater Wind development, see The Resource Planning Process within the Overview section of Item 7 Managements Discussion and Analysis of Financial Condition and Results of Operations. Solar PGE has four contracts representing 57 MW of capacity to purchase power generated from photovoltaic solar projects. Two of these projects extend to 2036 while the other two extend to 2037 and 2042. The expected energy from these solar resources will vary from the nameplate capacity due to varying solar conditions. Construction on the solar and battery components of Wheatridge was completed in 2022. The solar component of Wheatridge supplies the Company with 50 MW of capacity. The facility also includes 30 MW related to the battery component which is not reflected in the table above. Subsidiaries of NextEra Energy Resources, LLC own the solar and battery components, and sell their portion of the output to PGE. Biomass PGE has one contract to purchase biomass energy that is set to expire in June 2023. Green Future Impact Program PGE has three contracts representing 360 MW of capacity to purchase power generated from renewable resources to support the Green Future

Impact Program: a 15-year contract with Avangrid Renewables representing 162 MW from a renewable solar facility in Gilliam County, Oregon that was placed in service in January 2023. This additional capacity is not reflected in the table above; and a 15-year contract with Avangrid Renewables representing 138 MW from a renewable solar facility in Wasco County, Oregon that is expected to be placed in service in December 2023. This additional capacity is not reflected in the table above. a 15-year contract with Avangrid Renewables representing 60 MW from a renewable solar facility in Wasco County, Oregon that is expected to be placed in service in December 2023. This additional capacity is not reflected in the table above. For additional information on the Green Future Impact Program, see Customer Choice Programs within the Customers and Revenues section of this Item 1. Short-term contracts These contracts are for delivery periods of one month up to one year in length. They are entered into with various counterparties to provide additional firm energy to help meet the Companys load requirements. PGE also utilizes spot purchases of power in the open market to secure the energy required to serve its retail customers. Such purchases are made under contracts that range in duration from 15 minutes to less than one month. PGE is a market participant in the western EIM, which allows certain of the Companys generating plants to receive automated dispatch signals from the California Independent System Operator (CAISO) for load balancing with other western EIM participants in five-minute intervals. For additional information regarding PGEs power purchase contracts, see Note 16, Commitments and Guarantees and Note 17, Leases, in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data. Future Energy Resource Strategy PGEs Integrated Resource Plan (IRP) outlines the Companys plan to meet future customer demand and describes PGEs future energy supply strategy. For a detailed discussion of the IRPs, see Investing in a Clean Energy Future within the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Transmission and Distribution Transmission systems deliver energy from generating facilities to distribution systems for final delivery to customers. PGE schedules energy deliveries over its transmission system in accordance with FERC requirements and operates one BAA in its service territory. In 2022, PGE delivered approximately 27 million megawatt hours (MWh) through 1,255 circuit miles of transmission lines operating at or above 115 kilovolts (kV). PGEs transmission system is part of the Western Interconnection, the regional grid in the western United States. The Western Interconnection includes the interconnected transmission systems of 11 western states, two Canadian provinces and parts of Mexico, and is subject to the reliability rules of the WECC and the NERC. PGE relies on transmission contracts with Bonneville Power Administration (BPA) to transmit a significant amount of the Companys generation to serve its distribution system. PGEs transmission system, together with contractual rights on other transmission systems, enables the Company to integrate and access generation resources to meet its customers energy requirements. PGEs generation is managed on a coordinated basis to obtain maximum load-carrying capability and efficiency. PGE has announced its

intention to join the Western Power Pool and a binding resource adequacy program for the region known as the Western Resource Adequacy Program (WRAP). For further information, see Operating Activities within the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. The Companys wholesale transmission activities are regulated by the FERC and are offered on a non-discriminatory basis, with all potential customers provided equal access to PGEs transmission system through PGEs OATT. In accordance with its OATT, PGE offers several transmission services to wholesale customers, including: Network integration transmission service, a service that integrates generating resources to serve retail loads; Short- and long-term firm point-to-point transmission service, a service with fixed delivery and receipt points; and Non-firm point-to-point service, an as available service with fixed delivery and receipt points. For additional information regarding the Companys transmission and distribution facilities, see Transmission and Distribution in Item 2.Properties. Environmental Matters PGEs operations are subject to a wide range of environmental protection laws and regulations, which pertain to air and water quality, endangered species and wildlife protection, and hazardous material. Various state and federal agencies also regulate environmental matters that relate to the siting, construction, and operation of generation, transmission, and substation facilities and the handling, accumulation, clean-up, and disposal of toxic and hazardous substances. In addition, certain of the Companys hydroelectric projects and transmission facilities are located on property under the jurisdiction of federal and state agencies, and/or tribal entities that have authority in environmental protection matters. The following discussion provides further information on certain environmental regulations that affect the Companys operations and facilities. Air Quality Clean Air Act PGEs operations, primarily its thermal generating plants, are subject to regulation under the federal Clean Air Act (CAA), which addresses particulate matter, hazardous air pollutants, and GHG emissions, among other things. Oregon and Montana, the states in which PGEs thermal facilities are located, also implement and administer certain portions of the CAA and have set standards that are at least as stringent as federal standards. PGE manages its air emissions at its thermal generating plants by the use of low sulfur fuel, emissions and combustion controls and monitoring, and sulfur dioxide allowances awarded under the CAA. Climate Change In 2015, the United States Environmental Protection Agency (EPA) released the Clean Power Plan (CPP), under which each state would have to reduce overall carbon dioxide emissions from its power sector on a state-wide basis. In 2016, the United States Supreme Court halted implementation and enforcement of the CPP. In 2018, the EPA proposed the more narrowly focused Affordable Clean Energy (ACE) rule, to repeal and replace the CPP and, in 2019, finalized the ACE rule, which established guidelines for states to develop plans to address GHG emissions from individual, existing coal-fired plants, such as Colstrip in the case of PGE. With the finalization of the ACE rule, the CPP was repealed. However, on January 19, 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE rule and remanded it, in full, back to the EPA. Notwithstanding

objections that the EPA intended to issue a new rule that took recent changes in the electricity sector into account, on October 29, 2021, the U.S. Supreme Court agreed to hear an appeal of the D.C. Circuit decision. The Supreme Court, in a February 28, 2022 decision, determined that the broad approach in the CPP regulating emissions exceeded the powers granted to EPA by Congress. The Court did not expressly determine whether EPA can regulate power sector GHG emissions through its other regulatory authority and the EPA has indicated it intends to issue a proposed successor rule to the CPP in March 2023. PGE will continue to assess the Supreme Courts decision, as well as any further EPA response, for impacts on Colstrip and the Companys existing natural gas fleet. House Bill (HB) 2021 In June 2021, the Oregon Legislature passed HB 2021, which requires retail electricity providers to reduce GHG emissions associated with serving Oregon retail electricity consumers 80% by 2030, 90% by 2035, and 100% by 2040, compared to their baseline emissions levels. The baseline levels for PGE are the average annual emissions for the years 2010, 2011, and 2012 associated with the electricity sold to its retail electricity consumers as reported to the Oregon Department of Environmental Quality (ODEQ). See HB 2021 in the Laws and Regulations section of the Overview for additional information. Any laws that would impose taxes or mandatory reductions in GHG emissions may have a material impact on PGEs operations, as the Company utilizes fossil fuels in its own power generation and other companies use such fuels to generate power that PGE purchases in the wholesale market. If incremental costs were incurred as a result of changes in the regulations regarding GHG emissions, the Company would seek recovery in customer prices. For more information regarding GHG emissions and related environmental regulation, including Oregons RPS and the Companys goals in this area, see Renewable Energy under State Regulation in the Regulation section of this Item 1. and Company Strategy in the Overview section of Item 7.Managements Discussion and Analysis of Financial Condition and Results of Operations. Water Quality The federal Clean Water Act requires that any federal license or permit to conduct an activity that may result in a discharge to waters of the United States must first receive a water quality certification or permit from the state in which the activity will occur. In Oregon, Montana, and Washington, the Department of Environmental Quality and Department of Ecology of each state are responsible for reviewing proposed projects under such requirements to ensure that federally approved activities will meet water quality standards and policies established by the respective state. PGE has obtained permits or certificates of compliance for its hydroelectric operations under the FERC licenses and continues to monitor and update equipment to meet federal and state standards. Threatened and Endangered Species and Wildlife Fish Protection The federal Endangered Species Act (ESA) has granted protection to many populations of migratory fish species in the Pacific Northwest. Long-term recovery plans for these species continue to have operational impacts on many of the regions hydroelectric projects. PGE continues to implement fish protection measures at its hydroelectric projects that were prescribed by the U.S. Fish and Wildlife Service and the National

Marine Fisheries Service under their authority granted in the ESA and the FPA. Conditions required with the operating licenses are expected to result in a minor reduction in power production and continued capital spending to modify the facilities to enhance fish passage and survival. Avian Protection Various statutes, including the Migratory Bird Treaty Act and Bald and Golden Eagle Protection Act, contain provisions for civil, criminal, and administrative penalties resulting from the unauthorized take of migratory birds and eagles. Because PGE operates facilities that can pose risks to a variety of such birds and eagles, the Company developed an Avian Protection Plan to help address and reduce risks to avian species that may be affected by Company operations. PGE has implemented such a plan for its transmission, distribution, and thermal generation facilities and additional, specific plans for its wind generation facilities. Hazardous Material PGE has a comprehensive program to comply with requirements of both federal and state regulations related to the storage, handling, and disposal of hazardous materials. The handling and disposal of hazardous materials from Company facilities is subject to regulation under the federal Resource Conservation and Recovery Act. In addition, the use, disposal, and clean-up of polychlorinated biphenyls, contained in certain electrical equipment, are regulated under the federal Toxic Substances Control Act. PGE is also subject to the Comprehensive Environmental Response Compensation and Liability Act, commonly referred to as Superfund, which provides authority to the EPA to assert joint and several liability for investigation and remediation costs for designated Superfund sites. An investigation by the EPA that began in 1997 of a segment of the Willamette River in Oregon known as Portland Harbor, revealed significant contamination of river sediments and prompted the EPA to designate Portland Harbor as a Superfund site. The EPA has listed PGE among the more than one hundred Potentially Responsible Parties (PRPs) in this matter, as PGE historically owned or operated property near the river. For additional information regarding the EPA action on Portland Harbor, see Note 19, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data. PGE is subject to regulation by the United States Department of Energy (USDOE), which, under the Nuclear Waste Policy Act of 1982, is responsible for the permanent storage and disposal of spent nuclear fuel. PGE has contracted with the USDOE for permanent disposal of spent nuclear fuel from Trojan that is stored in the Independent Spent Fuel Storage Installation (ISFSI), an NRC-licensed interim dry storage facility that houses the fuel. The NRC approved the transfer of spent nuclear fuel from a spent fuel pool to the ISFSI where it is expected to remain until permanent off-site storage is available. Shipment of the spent nuclear fuel from the ISFSI to off-site storage is not expected to be completed prior to 2059. For additional information regarding this matter, see Trojan decommissioning activities in Note 8, Asset Retirement Obligations, in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data. Human Capital Management PGEs talent and culture are vital to its ability to execute its business strategy and realize continued success. Accordingly, the Company seeks to attract and retain a talented,

motivated, and diverse workforce and maintain a culture that reflects PGEs Guiding Behaviors, drive for performance, and commitment to acting with the highest levels of honesty, integrity, compliance, and safety. Employees and Collective Bargaining Agreements PGE had 2,873 employees in its workforce as of December 31, 2022, with 673 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers (IBEW). One agreement covers 610 employees, which expires March 2025, and the other covers 63 employees, which expires August 2027. The partnership with IBEW is key to a holistic labor relations approach. In addition, PGE utilizes independent contractors and temporary personnel to supplement its workforce. Competitive Pay and Benefits PGE is committed to pay equity among its employees and offers a wide range of market-competitive benefits, including comprehensive health and welfare benefits and a 401(k) retirement plan, designed to support the physical, mental, and financial well-being of its employees. Talent Development PGE provides a variety of training and development programs for employees, as well as tuition reimbursement for job-related coursework. PGE offers a mentorship program for all regular, non-represented PGE employees to help support their growth and development. The PGE Board of Directors oversees executive talent development with the assistance of the Nominating, Governance, and Sustainability Committee and the Compensation, Culture and Talent Committee in an effort to maximize the pool of internal candidates. At least annually, the Board conducts reviews of succession plans for senior management, which includes a review of the qualifications and development plans of potential internal candidates and diversity of the succession pipeline. The Compensation, Culture and Talent Committee regularly conducts more in-depth reviews of development plans for promising management talent. PGE conducts employee engagement surveys periodically to give employees the opportunity to share their perspectives and provide feedback. Survey results are shared with PGE management so that managers can take action towards improving the employee experience. Health and Safety PGE is committed to providing a safe and healthy place of business for employees, customers, and the public. Management has established an Executive Safety Council that has oversight of the Companys efforts to create a safe workplace. In addition, PGE provides various safety resources to its employees, such as safety manuals, trainings, and incident reporting tools that are all designed to incorporate safe practices into all daily activities and promote in all employees a sense of personal commitment, responsibility, and obligation regarding safety. PGE also has an Employee Assistance Program that provides free and confidential wellness counseling to all employees and their families. Diversity, Equity, and Inclusion PGE promotes an inclusive workforce through pay equity practices, racial equity training, and development opportunities for women and people of color to advance into management. Black, Indigenous, and People of Color comprise over 26% of its employees and nearly 26% of management. One third of its employees and management, including its CEO, are female. PGE also promotes diversity and economic development through its suppliers. The Companys supplier diversity program

provides an opportunity in all competitive bid events for qualified minority-owned, women-owned, disabled veteran-owned, and emerging small business suppliers. COVID-19 Since the beginning of the COVID-19 pandemic, PGE has taken steps to protect employees. The Company continues to prioritize the health and safety of its employees and be informed by federal, state and local officials to align its efforts with current information. Information about Executive Officers The following are PGEs current executive officers: ##TABLE_START Name Age Current Position and Previous Experience Year Appointed Officer James A. Ajello 69 Senior Vice President, Finance, Chief Financial Officer, Treasurer and Corporate Compliance Officer (January 2021 to present), Senior Advisor (November 2020 to December 2020), Executive Vice President and Chief Financial Officer at Hawaiian Electric Industries (January 2009 to April 2017 - retired), Senior Vice President, Business Development at Reliant Energy (January 2000 to January 2009), Managing Director, UBS Securities (January 1984 to August 1998). 2021 Larry N. Bekkedahl 61 Senior Vice President, Advanced Energy Delivery (July 2021 to present), Vice President, Grid Architecture, Integration and Systems Operations (January 2019 to July 2021), Vice President Transmission and Distribution (August 2014 to January 2019). Senior Vice President of Transmission Services at BPA (June 2012 to August 2014), Vice President of Engineering and Technical Services at BPA (2008 to June 2012). 2014 Nicholas G. Blosser 52 Vice President Public Affairs (August 2022 to present), Chief of Staff and Deputy Cabinet Secretary and Special Assistant to the President, Office of Cabinet Affairs at The White House (March 2021 to July 2022), Intergovernmental Affairs and State Lead, Biden-Harris Transition Team (November 2020-January 2021), Chief of Staff for Oregon Governor Kate Brown (February 2017 to November 2020), Co-Founder and CEO of Celilo Group Media, Inc. (January 2000 to February 2017) 2022 M. Angelica Espinosa 45 Vice President, General Counsel (March 2022 to present), Deputy General Counsel and Corporate Secretary (June 2021 to March 2022), Chief Risk Officer and Vice President of Safety and Compliance at Southern California Gas Company (January 2019 to June 2021), Vice President, Compliance Governance and Corporate Secretary at Sempra Energy (November 2016 to January 2019) 2022 Bradley Y. Jenkins 59 Vice President, Utility Operations (January 2019 to present), Vice President, Generation and Power Operations (October 2017 to January 2019), Vice President, Power Supply Generation (September 2015 to October 2017), General Manager, Diversified Plant Operations, (November 2013 to August 2015), Plant General Manager, Boardman (September 2012 to November 2013), Operations Manager, Boardman (March 2012 to September 2012). 2015 John T. Kochavatr 49 Vice President, Information Technology and Chief Information Officer (February 2018 to present). Senior Vice President and Chief Information Officer at SUEZ Water Technologies Solutions (formerly General Electric Water and Process Technologies) (October 2017 to January 2018), Chief Information Officer and Chief Digital Officer at General Electric Water and Process Technologies (November 2012 to September 2017). 2018 ##TABLE_END##TABLE_START Anne F. Mersereau 60 Vice President, Human Resources, Diversity, Equity and Inclusion (January 2016 to present),

Ticker: POR, Sector: Utilities, Filed At: 2023-02-15T19:18:09-05:00

Employee Services Manager (January 2014 to January 2016), Change Management Consultant (January 2012 to January 2014), Human Resources Business Partner (July 2009 to December 2011). 2016 Maria M. Pope 57 President (October 2017 to present) and Chief Executive Officer (January 2018 to present), Senior Vice President, Power Supply, Operations and Resource Strategy (March 2013 to December 2017), Senior Vice President, Finance, Chief Financial Officer and Treasurer (January 2009 to February 2013). Board director (January 2006 to December 2008). Vice President and Chief Financial Officer for Mentor Graphics Corporation (July 2007 to December 2008). 2009 Brett M. Sims 54 Vice President, Strategy, Regulation and Energy Supply (October 2020 to present), Senior Director of Strategy, Commercial and Regulatory Affairs (September 2017 to October 2020), Director of Origination, Structuring Resource Strategy (May 2001 to September 2017). 2020 ##TABLE_END ITEM 1A. RISK FACTORS. When evaluating PGE and any investment in its securities, investors should consider carefully the following risk factors and all other information contained in this Annual Report on Form 10-K and in the other documents that the Company files from time to time with the SEC. The events described in the risk factors could have material effects on PGEs business, financial condition, results of operations, or cash flows, or that materially adversely affect PGEs results and cause such results to differ materially from projected results. Risk and uncertainties not currently known to the Company or that are currently deemed to be immaterial may also harm PGE. If any of these risks occur, PGEs business, financial condition, results of operations, and/or cash flows could be materially adversely affected, and the trading prices of the Companys securities could substantially decline. BUSINESS AND OPERATIONAL RISKS The effects of unseasonable or severe weather and other natural phenomena can adversely affect the Companys financial condition and results of operations, and the effects of climate change could result in more intense, frequent, and extreme weather events. Weather conditions can adversely affect PGEs revenues and costs, impacting the Companys results of operations. Variations in temperatures can affect customer demand for electricity, with warmer-than-normal winter seasons or cooler-than-normal summer seasons reducing the demand for energy. Weather conditions are the dominant cause of usage variations from normal seasonal patterns, particularly for residential customers. Rapid increases in load requirements resulting from unexpected weather changes, particularly if coupled with transmission constraints, could adversely impact PGEs cost and ability to meet the energy needs of its customers. Conversely, rapid decreases in load requirements could result in the sale of excess energy at depressed market prices. Changes in the global and local climate could result in more intense, frequent, and extreme weather events such as ice and snowstorms, high wind, flooding, changes in regional rainfall and snowpack levels, high heat events, drought conditions, and increased risk of wildfires. These events may disrupt energy delivery, cause power outages, and damage the Companys facilities and transmission and distribution system. Such events could result in a reduction in revenue and an increase in additional costs to restore service, repair facilities, purchase power and fuel to serve PGE load, and

procure insurance related to such impacts. In response to more intense, frequent, and severe weather events, PGE may need to make additional investments in generation, transmission, and distribution assets to enhance reliability and resiliency. Severe weather may also require increased PGE personnel availability, which could result in increased operating expenses as well increased safety risk. In certain instances, PGE relies on mutual aid support to assist in the recovery from severe weather. Lack of availability of mutual aid support could result in increased time to restore services to customers as well as increased costs and decreased customer satisfaction. Wildfires of greater size and prevalence, such as those of a magnitude seen in Oregon in recent years, could negatively affect public safety, the resilience of the electric grid, customers demand for power and PGEs ability and cost to procure adequate power and fuel supplies to serve its customers, PGE s ability to access the wholesale energy market, PGEs ability to operate its generating facilities and transmission and distribution systems, PGEs costs to maintain, repair, and replace such facilities and systems, and recovery of costs. PGE may be unable to effectively implement a public safety power shutoff (PSPS) and de-energize its system in the event of heightened wildfire risk, or the PSPS may not be able to prevent a wildfire, which could lead to potential liability if energized systems are determined to be the cause of wildfires that result in harm. Capital investment and operating expenses related to this risk may not be recoverable through increases in customer prices. Cybersecurity attacks, data security breaches, physical attacks and security breaches, acts of terrorism, or other similar events that could disrupt PGEs operations, require significant expenditures, or result in claims against the Company. In the normal course of business, PGE collects, processes, and retains sensitive and confidential customer and employee information, as well as proprietary business information, and operates systems that directly impact the availability of electric power and the transmission of electric power in its service territory. PGE owns and operates generation, transmission, distribution, and other facilities that depend on information technology systems. A cyber-attack may cause large-scale disruption to the U.S. bulk power system or PGE operations and could target the Companys computer systems, software, or networks to achieve such disruption. Generation, transmission, and distribution facilities, in general, have been identified as potential targets of physical or cyber-attacks. In addition, physical attacks on transmission and distribution facilities have occurred in the United States. Despite the security measures in place, the Companys systems and assets, and those of third-party service providers, could be vulnerable to cybersecurity attacks, data security breaches, physical attacks and security breaches, acts of terrorism, or other similar events that could disrupt operations, cause damage to the Companys generation, transmission, or distribution facilities, impact reliability of the transmission and distribution system, information technology systems, inhibit the capability of equipment or systems to function as designed or expected, prevent service to customers or collection of revenues, or result in the release of sensitive or confidential customer, employee, or Company information. Such events could cause a shutdown of service, expose PGE to

liability, or cause reputational damage. In addition, the Company may be required to expend significant capital and other resources to protect against security breaches or to alleviate problems caused by security breaches. A breach of certain business systems could impact PGEs ability to initiate, authorize, process, record, and report financial information. The cost of repairing damage to PGEs facilities and infrastructure caused by acts of terrorism, and the loss of revenue if such events prevent PGE from providing utility service to its customers, could adversely impact its financial condition and results of operations. PGE maintains insurance coverage against some, but not all, potential losses resulting from these risks. However, insurance is limited in scope and subject to exceptions, and may not be adequate to protect the Company against liability in all cases and insurers may dispute or be unable to perform their obligations to the Company, or may not be available at rates that are commercially reasonable. Natural or human-caused disasters and other risks could damage the Companys facilities and disrupt delivery of electricity resulting in significant property loss, repair costs, and reduced customer satisfaction. PGE has exposure to natural and human-caused disasters and other risks, including, but not limited to, a pandemic such as COVID-19, earthquake, accidents, equipment failure, acts of terrorism, acts of vandalism, computer system outages and other events. Such events, which may be amplified by the fact that PGEs business activities are concentrated in one region, could disrupt PGE operations, damage PGE facilities and systems, interrupt the delivery of electricity, increase repair and service restoration expenses, reduce revenues, cause the release of harmful materials, cause fires or flooding, and subject the Company to liability. Such events, if repeated or prolonged, can also affect customer satisfaction and the level of regulatory oversight. Electric utility operations may pose risk to public and workers safety. The operation of electric generation, transmission, and distribution infrastructure involves inherent risks, including breakdown or failure of equipment, motor vehicle accidents, fires involving the utilitys equipment, dam failure at company-owned hydroelectric facilities, public and worker safety, human contact with energized equipment, and operator error. A portion of the Companys operations relies on Company- or third party-owned natural gas transmission and distribution infrastructure and involves inherent risks, such as leaks, explosions, mechanical problems, and worker and public safety. These risks could cause significant harm to workers and the public including loss of human life, significant damage to property, adverse impacts on the environment and impairment of PGEs operations, all of which could result in financial losses that would have a material adverse effect on the Companys results of operations and financial condition. PGE is also required to comply with new and changing regulatory standards involving safety compliance. The cost to comply with such requirements could be significant, and failure to meet these regulatory standards could result in substantial fines. The inability to attract and retain a qualified workforce and to maintain satisfactory collective bargaining agreements without prolonged labor disruptions, may adversely affect PGEs results of operations. PGEs workforce includes a diverse mix of skilled professional, managerial, and technical employees, including employees represented

under collective bargaining agreements. Workforce management risks include the risk of retaining key employees, turnover due to demographic challenges as employees approach retirement age, and turnover due to macroeconomic trends such as the impacts of inflation on pensions and other retirement funding. PGE faces competition for employees within the industry and in local geographies. The Company faces the risk of labor disruption due to the outcomes of labor negotiations or the possibility that employees not currently subject to collective bargaining agreements may organize. PGE relies on a contracted workforce for specific business purposes, and may experience increased costs or inability to find contracted workforce, which may result in a negative impact on operations as well as financial impact. The construction of new facilities and the modifications or replacements of existing facilities, is subject to risks that could result in the disallowance of certain costs for recovery in customer prices or higher operating costs. Long-term increases in both the number of customers and demand for energy will require continued expansion and upgrade of PGEs generation, transmission, and distribution systems. Construction of new facilities and modifications or replacements of existing facilities could be affected by factors such as unanticipated delays and cost increases, including supply chain disruption and cost inflation, availability of skilled workforce, increases in interest rates, failure of counterparties to perform under agreements, and the failure to obtain, or delay in obtaining, necessary permits from state or federal agencies or tribal entities. Delays and cost increases could result in failure to complete the projects or the abandonment of capital projects, which could eliminate or impair PGEs ability to recover related costs in the rate determination process. In addition, failure to complete construction projects according to specifications could result in reduced plant efficiency, equipment failure, and plant performance that falls below expected levels, which could increase operating costs. REGULATORY, LEGAL, AND COMPLIANCE RISKS PGE is subject to extensive price regulation and relies on recovery of costs, the uncertainty of which affect the Companys operations and costs. PGE is subject to ongoing regulation by the FERC, the OPUC and by certain federal, state, and local authorities under environmental, permitting, and other laws. Such regulation significantly influences the Companys operating environment and affects many aspects of its business. The Company cannot predict with certainty the future course of such changes or the ultimate effect that they might have on its business, and such changes could delay or adversely affect business planning and transactions and substantially increase the Companys costs. OPUC regulates the prices that PGE charges, which is a major factor in determining the Companys operating income, financial position, liquidity, and credit ratings. As a general matter, PGE relies on customer prices to recover most of the costs incurred in connection with the operation of its business, including, among other things, costs related to capital projects (such as the construction of new facilities or the modification of existing facilities), the costs of compliance with legislative and regulatory requirements (including environmental laws), and the costs of damage from storms and other natural disasters. Regulators may deny recovery of costs it considers imprudently incurred. Although the

OPUC is required to establish customer prices that are fair, just, and reasonable, it has significant discretion in the interpretation of this standard. PGE attempts to manage its costs at levels consistent with OPUC-approved prices. However, if the Company is unable to do so, or if such cost management results in increased operational risk, the Companys financial and operating results could be adversely affected. PGE is subject to various legal and regulatory proceedings, the outcome of which is uncertain, and resolution unfavorable to PGE could adversely affect its results of operations, financial condition, or cash flows. In the normal course of its business, PGE is subject to regulatory proceedings, lawsuits, claims, and other matters, which could result in adverse judgments, settlements, fines, penalties, injunctions, or other relief. Such matters include governmental policies, legislative action, and regulatory audits, investigations, and actions, including those of the FERC and OPUC with respect to allowed rates of return, financings, electricity pricing and price structures, acquisition and disposal of facilities and other assets, construction and operation of plant facilities, transmission of electricity, recovery of power costs, operating expenses, deferrals, timely recovery of costs and capital investments, and current or prospective wholesale and retail competition. These matters are subject to many uncertainties, the ultimate outcome of which management cannot predict. The final resolution of certain matters in which PGE is involved could result in disallowance of operating expenses previously deferred or could require that the Company incur expenditures over an extended period and in a range of amounts that could have an adverse effect on its cash flows and results of operations. Similarly, the terms of resolution could require the Company to change its business practices and procedures, which could also have an adverse effect on its cash flows, financial position, or results of operations. New laws, changes in legal precedent, or novel interpretations of existing regulations could also result in adverse effects on cash flows and results of operations. There are certain pending legal and regulatory proceedings that may have an adverse effect on results of operations and cash flows for future reporting periods. For additional information, see Item 3.Legal Proceedings, Regulatory Matters within the Overview of Item 7. Managements Discussion and Analysis of Financial Condition and Results of Operations, and Note 19, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.Financial Statements and Supplementary Data. Compliance with environmental laws and regulations may result in capital expenditures, increased operating costs and various liabilities, and adverse impact on the Companys results of operations. PGE is subject to various environmental laws, regulations, and other standards including federal, state and local environmental statutes, rules and regulations relating to air quality, water quality and usage, soil quality, emissions of greenhouse gases (GHG) such as carbon dioxide, waste management, hazardous wastes, fish, avian and other wildlife mortality and habitat protection, historical artifact preservation, natural resources, health, and safety. Compliance with such laws and regulations could, among other things, prevent or delay the development of power generation and transmission and distribution facilities, restrict output of facilities, limit the use of fuels required for power generation,

require additional pollution control equipment, require investment in non-emitting resources, and otherwise increase costs and increase capital expenditures. A portion of PGEs total system load is supplied with power generated from hydroelectric and wind generating resources. Operation of these facilities is subject to regulation related to the protection of fish and wildlife. Changes to the listing of various plants and species of fish, birds, and other wildlife as threatened or endangered could result in increased mitigation activities, which could have a material impact on PGEs financial condition and results of operations. Salmon recovery plans could include further major operational changes to the regions hydroelectric projects, including those owned by PGE and those from which the Company purchases power under long-term contracts. In addition, laws relating to the protection of migratory birds and other wildlife could impact the development and operation of transmission and distribution lines and wind projects. Also, new interpretations of existing laws and regulations could be adopted or become applicable to such facilities, which could further increase required expenditures for salmon recovery and endangered species protection and reduce the availability of hydroelectric or wind generating resources to meet the Companys energy requirements. Compliance with any new or additional GHG emissions reduction requirements could require PGE to incur significant expenditures, including those related to carbon capture and sequestration technology, purchase of emission allowances and offsets, fuel switching, and the retirement or replacement of high-emitting generation facilities with non-emitting facilities. The cost to comply with potential GHG emissions reduction requirements is subject to significant uncertainties, including those related to: the timing of the implementation of emissions reduction rules; required levels of emissions reductions; requirements with respect to the allocation of emissions allowances; the maturation, regulation, and commercialization of carbon capture, sequestration, and storage technology; and PGEs compliance alternatives. Although the Company cannot currently estimate the effect of future laws and regulations on its results of operations, financial condition, or cash flows, the costs of compliance with such legislation or regulations could be material. Changes in tax laws may have an adverse impact on the Companys financial position, results of operations, and cash flows. PGE makes judgments and interpretations about the application of tax law when determining the provision for taxes. Such judgments include the timing and probability of recognition of income, deductions, and tax credits, which are subject to challenge by taxing authorities. Additionally, treatment of tax benefits and costs for ratemaking purposes could be different than what the Company anticipates or requests from the State regulatory commission, which could have a negative effect on the Companys financial condition and results of operations. PGE owns and operates renewable generating facilities, which generate federal production tax credits (PTCs) that PGE uses to reduce its federal tax obligations. The amount of PTCs earned depends on the level of electricity output generated and the applicable tax credit rate. A variety of operating and economic parameters, including adverse weather conditions and equipment reliability, could significantly reduce the PTCs generated by the Companys wind facilities resulting

in a material adverse impact on PGEs financial condition and results of operations. These PTCs generate tax credit carryforwards that the Company plans to utilize in the future to reduce income tax obligations. If PGE cannot generate enough taxable income in the future to utilize all of the tax credit carryforwards before the credits expire, the Company may incur material charges to earnings. ECONOMIC, FINANCIAL, AND MARKET RISKS A decrease in customer demand for electricity may negatively impact PGEs business. Unfavorable economic conditions in Oregon, such as, for example, increased inflation, may result in reduced demand for electricity and impair the financial stability of PGEs customers. Such reductions in demand could adversely affect PGEs results of operations and cash flows. Economic conditions could also result in an increased level of uncollectible customer accounts and cause the Companys vendors and service providers to experience cash flow problems and be unable to perform under existing or future contracts. Customer demand could also be negatively impacted by PGEs ability to attract and retain customers, mandated energy efficiency measures, demand side management programs, potential formation of community choice aggregation programs, distributed generation resources, and economic and demographic conditions, such as population changes, job and income growth, new construction, new business formation and the overall level of economic activity. Development, improvement, and adoption of technological advances could lead to declines in energy use per customer. Some or all of these factors could impact the demand for electricity. The decline in revenues due to decreased customer demand for electricity may increase customer prices for remaining customers, as PGEs revenue requirement is designed to cover its fixed utility operating expenses. Increased customer prices could further reduce customer demand for electricity and strain PGEs ability to attract and retain customers. The loss of customers, the inability to replace those customers with new customers, and the decrease in demand for electricity could negatively impact PGEs financial condition and results of operations. Capital and credit market conditions could adversely affect the Companys access to capital, cost of capital, and ability to execute its strategic plan. Access to capital and credit markets is important to PGEs ability to operate. The Company expects to issue debt and equity securities, as necessary, to fund its future capital requirements. Volatility of interest rates could negatively impact PGEs cost of debt and results of operations. In addition, contractual commitments and regulatory requirements may limit the Companys ability to delay or terminate certain projects. If the capital and credit market conditions in the United States and other parts of the world deteriorate, the Companys future cost of debt and equity capital, as well as access to capital markets, could be adversely affected. In addition, sales or issuances of substantial amounts of PGEs common stock in the public market, including upon settlement of the forward sale agreements entered into in 2022, could cause the market price of PGEs common stock to decline. This could impair the Companys ability to raise additional capital through the sale of equity securities. Future sales or issuances of common stock or other equity-related securities could be dilutive to holders of common stock and could adversely affect their voting and other rights and

economic interests. PGE expects to raise additional capital in the future. PGE may raise additional funds through public or private equity or debt offerings or other financings, as well as additional borrowings under existing credit facilities. Any new debt financing entered into may involve covenants that restrict operations more than PGEs current outstanding debt and credit facilities. These restrictive covenants could include limitations on additional borrowings, specific restrictions on the use of assets, and prohibitions or limitations on the Companys ability to create liens, pay dividends, receive distributions from subsidiaries, redeem or repurchase stock or make investments. These factors could hinder the Companys access to capital markets and limit or delay the ability to carry out the Companys capital expenditure plan or pursue other opportunities beyond the current capital expenditure plan. The declaration of future dividends is at the discretion of the Board of Directors and is not guaranteed and, in some circumstances, the payment of dividends may be limited by the terms of PGEs debt instruments. PGE has historically paid regular quarterly dividends on common stock. However, the declaration of dividends is at the discretion of PGEs Board of Directors and is not guaranteed. The amount of common stock dividends, if any, will depend upon results of operations and financial condition, future capital expenditures and investments, the rights of holders of any outstanding shares of preferred stock, and other factors that the Board of Directors considers relevant. In addition, the terms of the Companys debt instruments may limit the payment of dividends. Under the Indenture of Mortgage and Deed of Trust, dated July 1, 1945, as amended and supplemented to date, between PGE and Wells Fargo Bank, National Association, so long as any of the first mortgage bonds are outstanding, the Company may not pay or declare dividends (other than stock dividends) on common stock or purchase or retire for a consideration (other than in exchange for other shares of PGEs capital stock or the proceeds from the sale of other shares of capital stock) any shares of capital stock of any class, if the aggregate amount distributed or expended after December 31, 1944 would exceed the aggregate amount of PGEs net income, as adjusted, available for dividends on common stock accumulated after December 31, 1944. At December 31, 2022, $399 million of accumulated net income was available for payment of dividends under this provision. Adverse changes in PGEs credit ratings could negatively affect its access to the capital markets and its cost of borrowed funds. Credit rating agencies routinely evaluate the Company, and their ratings of long-term and short-term debt are based on a number of factors, including the perceived supportiveness of the regulatory environment affecting the utility operations, the Companys cash generating capability, level of indebtedness, overall financial strength, the status of certain capital projects, as well as factors beyond PGEs control, such as tax reform, the state of the economy and industry generally. A ratings downgrade could increase fees on PGEs syndicated unsecured revolving credit facility, commercial paper program, and letter of credit facilities, increasing the cost of funding day-to-day working capital requirements, and could also result in higher interest rates on future long-term debt. A ratings downgrade could also restrict the Companys access to the commercial paper market, a principal source of short-term financing, or

result in higher interest costs. In addition, if Moodys Investors Service (Moodys) and/or SP Global Ratings (SP) reduce their rating on PGEs unsecured debt to below investment grade, the Company could be subject to requests by certain wholesale counterparties to post additional performance assurance collateral, which could have an adverse effect on the Companys liquidity and ability to participate in the wholesale markets. Under certain circumstances, banks participating in PGEs syndicated unsecured revolving credit facility could decline to fund advances requested by the Company or could withdraw from participation in the credit facility, which could adversely affect PGEs liquidity. PGE currently has a syndicated unsecured revolving credit facility with several banks for an aggregate amount of $650 million. The revolving credit facility provides a primary source of liquidity and may be used to supplement operating cash flow and as backup for commercial paper borrowings. The revolving credit facility represents commitments by the participating banks to make loans and, in certain cases, to issue letters of credit. The Company is required to make certain representations to the banks each time it requests an advance under the credit facility. However, in the event of a material adverse change in the business, financial condition, or results of operations of PGE, the Company may not be able to make such representations, in which case the banks would not be required to lend. PGE is also subject to the risk that one or more of the participating banks may default on their obligation to make loans under the credit facility. Adverse capital market performance could result in reductions in the fair value of benefit plan assets and increase the Companys liabilities related to such plans. Sustained declines in the fair value of the plans assets could result in significant increases in funding requirements, which could adversely affect PGEs liquidity and results of operations. Performance of the capital markets affects the value of assets that are held in trust to satisfy future obligations under PGEs defined benefit pension and other postretirement plans. Sustained adverse market performance could result in lower rates of return for these assets than projected by the Company and could increase PGEs funding requirements related to the plans. Additionally, changes in interest rates affect PGEs liabilities under the plans. As interest rates decrease, the Companys liabilities increase, potentially requiring additional funding. Performance of the capital markets also affects the fair value of assets that are held in trust to satisfy future obligations under the Companys non-qualified employee benefit plans, which include deferred compensation plans. As changes in the fair value of these assets are recorded in current earnings, decreases can adversely affect the Companys operating results. In addition, such decreases can require that PGE make additional payments to satisfy its obligations under these plans. The volatility of market prices for power and natural gas could adversely affect PGEs costs and ability to manage its energy supply, which could negatively impact the Companys liquidity and results of operations. As part of its normal business operations, PGE purchases and sells power and natural gas in the open market under short- and long-term contracts, which may specify variable prices or volumes. Market prices for power and natural gas are influenced primarily by factors related to supply and demand. These factors

generally include the adequacy of generating capacity, scheduled and unscheduled outages of generating facilities, hydroelectric and wind generation levels, prices and availability of fuel sources for generation, disruptions or constraints to transmission facilities, weather conditions, economic growth, and changes in technology. Volatility in these markets can affect the availability, price, and demand for power and natural gas. Disruption in power and natural gas markets could result in a deterioration of market liquidity, increase the risk of counterparty default, affect regulatory and legislative processes in unpredictable ways, affect wholesale power prices, and impair PGEs ability to manage its energy portfolio. Changes in power and natural gas prices can also affect the fair value of derivative instruments and cash requirements to purchase power and natural gas. If power and natural gas prices decrease from those contained in the Companys existing purchased power and natural gas agreements, PGE may be required to provide increased collateral, which could adversely affect the Companys liquidity. Conversely, if power and natural gas prices rise, especially during periods when the Company requires greater-than-expected volumes that must be purchased at market or short-term prices, PGE could incur greater costs than originally estimated. PGEs contract positions are not fully hedged against commodity prices, and hedges or other risk mitigations may not protect against significant losses. The risk of volatility in power costs is partially mitigated through the AUT and the PCAM. Application of the PCAM requires that PGE absorb certain power cost increases before the Company is allowed to recover any amount from customers. Accordingly, the PCAM is expected to only partially mitigate the potentially adverse financial impacts of forced generating plant outages, reduced hydro and wind availability, interruptions in fuel supplies, and volatile wholesale energy prices. PGE has put in place risk management policies, procedures, and controls to identify, quantify, and manage risk, however, these systems, processes, tools, and controls may not prevent material losses. Risk management procedures may not always be followed as intended, may not operate as designed, or may not identify all potential risks, including, without limitation, severe weather or employee misconduct. There is no assurance that PGEs risk management procedures will be effective in preventing or mitigating losses, and could have a material adverse effect on the Companys results of operation and financial condition. Reduced river flows, unfavorable wind conditions, and forced outages at generating and battery storage facilities can increase the cost of power required to serve customers. The Company could be required to replace energy expected from these sources with higher cost power from other facilities or with wholesale market purchases, which could have an adverse effect on results of operations. PGE derives a significant portion of its power supply from its own hydroelectric facilities and long-term purchase contracts with certain public utility districts in the state of Washington. Regional rainfall and snowpack levels affect river flows and the resulting amount of energy generated by these facilities. Shortfalls in energy expected from lower cost hydroelectric generating resources would require increased energy from the Companys other generating resources and/or power purchases in the wholesale market, which could have an adverse effect on results of

operations. PGE also derives a portion of its power supply from wind generating resources, for which the output is dependent upon wind conditions. Unfavorable wind conditions could require increased reliance on power from the Companys thermal generating resources or power purchases in the wholesale market, both of which could have an adverse effect on results of operations. Forced outages at generating facilities and battery storage facilities, both PGE-owned or under purchased power agreements, could result in power costs greater than those included in customer prices, in addition to increased repair and maintenance costs. Although the application of the PCAM could help mitigate adverse financial effects from any decrease in power supply, full recovery of any increase in power costs is not assured. Inability to fully recover such costs in future prices could have a negative impact on the Companys results of operations, as well as a reduction in renewable energy credits and loss of PTCs related to wind generating resources. The capacity provided by the Companys generating resources and third-party purchased power may not be sufficient to meet its customers energy demand requirements. PGE meets its customers energy demand requirements based on capacity obtained from its generating facilities and third-party power purchase agreements. The Company continuously evaluates how much capacity it will need to meet reasonably expected demands of customers and provide reasonable reserves. PGE is also required to file Integrated Resource Plans with the OPUC that detail the Companys plan to meet the future energy and capacity needs of its customers through a least-cost, least-risk combination of energy generation and demand reduction, while also aggressively reducing GHG emissions from the power supply. If the capacity provided by the Companys generating facilities and purchased power is not adequate to meet customers energy demands, PGE may be required to purchase more power from third parties, invest in acquiring additional generating or battery storage facilities, or invest in extending the operating life of existing generating assets. Any failure to obtain adequate capacity to meet customers energy demand requirements could increase its costs and negatively impact PGEs customer satisfaction, all of which could have an adverse impact on PGEs business and results of operations. Advances in energy technology could make PGEs business less competitive. A basic premise of PGEs business as a vertically integrated utility is the ability to produce electricity at competitive prices due to economies of scale. Furthermore, a key component of PGEs growth is its ability to construct, own, and operate facilities. Many companies and organizations conduct research and development activities to seek improvements in alternative technologies and distributed generation. Advancements in and creation of new technologies could include fuel cells and micro turbines, wind turbines, photovoltaic solar cells, distributed generation, nuclear energy, hydrogen, ongoing customer energy efficiency, two-way grid enabling customer-owned generation, and advances in batteries or energy storage. It is possible that advances in such technologies, or other current technologies, will reduce the cost of alternative methods of electricity production or storage to a level that is equal to or below that of existing methods. The electricity industry is undergoing significant change, including increased deployment of distributed

energy resources, technological advancements as described above, and political and regulatory developments. Electric utilities are experiencing increasing deployment of distributed energy resources, such as solar generation, energy storage, energy efficiency and demand response technologies. The deployment of these technologies supports PGEs decarbonization goals. The growth of new technologies will require modernization of the electric distribution grid to, among other things, accommodate increasing two-way flows of electricity and increase the grids capacity to interconnect these resources. A higher penetration of distributed energy resources may result in decreased customer demand, or may have impacts on grid reliability. Increased distributed energy resources and renewable energy resources will require new and sustained investments in grid modernization and transmission. If all such costs are not recoverable in rates, PGE could experience material increases in its commodity costs, which could impact PGEs results of operations, financial condition, or cash flows. It is also possible that alternative generation or storage resources are mandated, subsidized, or encouraged through legislation or regulation or otherwise are economically competitive and added to the available generation supply. Competitors may not be subject to the same operating, regulatory and financial requirements that the Company is, potentially causing a substantial competitive disadvantage for PGE. Changes in public policy, such as new tax incentives that PGE cannot take advantage of or efforts to deregulate the utility industry, could provide an advantage to competitors. Such alternative resources and regulatory or legislative actions could displace higher marginal cost generating units or make PGE less competitive in constructing, owning, and operating such facilities. Such a development could limit the Companys future growth opportunities and limit growth in demand for PGEs electric service. Changes in market conditions and environmental laws and regulations could negatively impact PGEs non-utility real estate investments. PGE owns, through a wholly owned subsidiary, its corporate headquarters building located in Portland, Oregon. A significant change in real estate values could adversely affect PGEs results of operations. PGE also owns unregulated properties that are currently or previously leased to third parties and located adjacent to PGEs T.W. Sullivan hydro generating facility. PGE has recorded a non-utility asset retirement obligation (ARO) for this site related to assets that are no longer in service. Significant changes in estimates for this non-utility ARO due to changes in environmental laws or regulations could adversely affect PGEs results of operations. Rapidly changing stakeholder expectations and standards with respect to PGEs environmental, social, and governance (ESG) programs could result in increased costs and exposure to incremental risk. Investors, lenders, rating agencies, customers, regulators, employees, and other stakeholders are increasing their focus on evaluating companies as corporate citizens based on their ESG programs and metrics. Based on PGEs ESG profile, investors and lenders may elect to increase their required returns on capital offered to the Company, reallocate capital, or not commit capital as a result of their assessment of the Companys ESG profile. Such actions by investors and lenders could increase PGEs cost of, or access to, capital and financing. PGE is

committed to the success of its ESG programs; however, if the Company fails to adapt or execute on its ESG strategies, or is perceived to have failed in addressing stakeholder ESG expectations or standards, which continue to evolve, PGE may suffer reputational damage, which could have a material adverse effect on its business, results of operations, and financial condition. Additionally, the cost of implementing and complying with such ESG programs could be material. Actions of activist shareholders could have a negative impact on PGEs business. Actions of activist shareholders, which can take many forms and arise in a variety of situations, could include engaging in proxy solicitations, advancing shareholder proposals, or otherwise attempting to effect changes and assert influence on the Companys board of directors and management. Dealing with such actions could result in substantial costs and divert managements and the Companys boards attention and resources from PGEs business and execution of its strategy. Such shareholder activism could give rise to perceived uncertainties regarding PGEs future, adversely affecting PGEs business opportunities, ability to access capital markets, relationships with its customers and employees, and make it more difficult to attract and retain a qualified workforce. Any such actions could have a material adverse effect on the Companys financial condition and results of operations and could cause significant fluctuations in the trading prices of its common stock based on market perceptions or other factors. PGEs business activities are concentrated in one region and future performance may be affected by events and factors unique to Oregon or the region. The Companys industry and geographic concentrations may increase exposure to risks arising from regional regulation or legislation, such as legislative action related to carbon emissions. These concentrations may also increase exposure to credit and operational risks due to counterparties, suppliers, and customers being similarly affected by changing conditions.

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ITEM 1. BUSINESS General (All Registrants) PPL, headquartered in Allentown, Pennsylvania, is a utility holding company, incorporated in 1994 to serve as the holding company for the regulated utility that is now PPL Electric and pursue other business activities in the deregulated power sector. PPL, through its regulated utility subsidiaries, delivers electricity to customers in Pennsylvania, Kentucky, Virginia, and Rhode Island; delivers natural gas to customers in Kentucky and Rhode Island; and generates electricity from power plants in Kentucky. PPL's principal subsidiaries at December 31, 2022 are shown below (* denotes a Registrant). ##TABLE_START PPL Corporation* PPL Capital Funding Provides financing for the operations of PPL and certain subsidiaries PPL Electric* Engages in the regulated transmission and distribution of electricity in Pennsylvania LKE A holding company that owns regulated utility operations through its subsidiaries, LGE and KU RIE Engages in the regulated transmission, distribution and sale of electricity and regulated distribution and sale of natural gas in Rhode Island LGE* Engages in the regulated generation, transmission, distribution and sale of electricity and regulated distribution and sale of natural gas in Kentucky KU* Engages in the regulated generation, transmission, distribution and sale of electricity, primarily in Kentucky Pennsylvania Regulated Segment Kentucky Regulated Segment Rhode Island Regulated Segment ##TABLE_ENDIn addition to PPL, the other Registrants included in this filing are as follows. PPL Electric , headquartered in Allentown, Pennsylvania, is a wholly owned subsidiary of PPL and a regulated public utility that is an electricity transmission and distribution service provider in eastern and central Pennsylvania. PPL Electric is subject to regulation as a public utility by the PAPUC, and certain of its transmission activities are subject to the jurisdiction of the FERC under the Federal Power Act. PPL Electric delivers electricity in its Pennsylvania service area and provides electricity supply to retail customers in that area as a PLR under the Customer Choice Act. PPL Electric was organized in 1920 as Pennsylvania Power Light Company. LGE, headquartered in Louisville, Kentucky, is a wholly owned subsidiary of LKE and a regulated utility engaged in the generation, transmission, distribution and sale of electricity and distribution and sale of natural gas in Kentucky. LGE is subject to regulation as a public utility by the KPSC, and certain of its transmission activities are subject to the jurisdiction of the FERC under the Federal Power Act. LGE was incorporated in 1913. KU, headquartered in Lexington, Kentucky, is a wholly owned subsidiary of LKE and a regulated utility engaged in the generation, transmission, distribution and sale of electricity in Kentucky and Virginia. KU is subject to regulation as a public utility by the KPSC and the VSCC, and certain of its transmission and wholesale power activities are subject to the jurisdiction of the FERC under the Federal Power Act. KU serves its Kentucky customers under the KU name and its Virginia customers under the Old Dominion Power name. KU was incorporated in Kentucky in 1912 and in Virginia in 1991. Segment Information (PPL) PPL is organized into three reportable segments as depicted in the chart above: Kentucky Regulated, which primarily represents the results of LGE and KU, Pennsylvania Regulated, which primarily represents the results of PPL Electric, and Rhode Island Regulated, which primarily represents the results of RIE. "Corporate and Other" primarily includes financing and other costs incurred at the corporate level that have not been allocated or assigned to the segments, as well as certain non-recoverable costs resulting from commitments made to the Rhode Island Division of Public Utilities and Carriers and the Attorney General of the State of Rhode Island in conjunction with the acquisition of Narragansett Electric. A comparison of PPL's Regulated segments is shown below. ##TABLE_START Kentucky Pennsylvania Rhode Island Regulated Regulated Regulated (a) For the year ended December 31, 2022: Operating Revenues (in billions) $ 3.8 $ 3.0 $ 1.0 Net Income (in millions) $ 507 $ 525 $ (44) Electricity delivered (GWh) 30,892 37,593 4,494 Natural gas delivered (Bcf) 31 14 At December 31, 2022: Regulatory Asset Base (in billions) (b) $ 11.7 $ 9.3 $ 3.2 Service area (in square miles) 8,000 10,000 1,200 Customers (in millions) 1.3 1.5 0.8 ##TABLE_END(a) On May 25, 2022, PPL Rhode Island Holdings acquired 100% of the outstanding shares of common stock of Narragansett Electric. The results of RIE are included in PPLs Rhode Island Regulated segment. See Note 9 to the Financial Statements for additional information. (b) Represents capitalization for Kentucky Regulated, rate base for Pennsylvania Regulated and Rhode Island Regulated. The amount for Rhode Island Regulated excludes acquisition-related adjustments for non-earning assets. See Note 2 to the Financial Statements for additional financial information by segment. Beginning on January 1, 2023, the Kentucky Regulated segment will consist primarily of the regulated electricity generation, transmission and distribution operations conducted by LGE and KU, as well as LGE's regulated distribution and sale of natural gas. Prior to January 1, 2023, the Kentucky Regulated segment also included the financing activities of LKE. The financing activity of LKE will be presented in Corporate and Other beginning on January 1, 2023. As a result of this change, beginning on January 1, 2023, PPLs segments will consist of the regulated operations of Kentucky, Pennsylvania and Rhode Island and will exclude any incremental financing activities of holding companies, which Management believes is a more meaningful presentation as it provides information on the core regulated operations of PPL. (PPL Electric, LGE and KU) PPL Electric has two operating segments, distribution and transmission, which are aggregated into a single reportable segment. LGE and KU are individually single operating and reportable segments. Kentucky Regulated Segment (PPL) The Kentucky Regulated segment consists primarily of the regulated electricity generation, transmission and distribution operations conducted by LGE and KU, as well as LGE's regulated distribution and sale of natural gas. In addition, the Kentucky Regulated segment includes certain financing and other costs at LKE. (PPL, LGE and KU) LGE and KU are engaged in the regulated generation, transmission, distribution and sale of electricity in Kentucky and, in KU's case, also Virginia. LGE also engages in the distribution and sale of natural gas in Kentucky. LGE provides electric service to approximately 433,000 customers in Louisville and adjacent areas in Kentucky, covering approximately 700 square miles in nine counties and provides natural gas service to approximately 334,000 customers in its electric service area and eight additional counties in Kentucky. KU provides electric service to approximately 541,000 customers in 77 counties in central, southeastern and western Kentucky and approximately 28,000 customers in five counties in southwestern Virginia, covering approximately 4,800 non-contiguous square miles. KU also sells wholesale electricity to two municipalities in Kentucky under load following contracts. See Note 3 to the Financial Statements for revenue information. Franchises and Licenses LGE and KU provide electricity delivery service, and LGE provides natural gas distribution service, in their respective service territories pursuant to certain franchises, licenses, statutory service areas, easements and other rights or permissions granted by state legislatures, cities or municipalities or other entities. Competition There are currently no other electric public utilities operating within the electric service areas of LGE and KU. From time to time, bills are introduced into the Kentucky General Assembly which seek to authorize, promote or mandate increased distributed generation, customer choice or other developments. Neither the Kentucky General Assembly nor the KPSC has adopted or approved a plan or timetable for retail electric industry competition in Kentucky. The nature or timing of legislative or regulatory actions, if any, regarding industry restructuring and their impact on LGE and KU, which may be significant, cannot currently be predicted. Virginia, formerly a deregulated jurisdiction, has enacted legislation that implemented a hybrid model of cost-based regulation. KU's operations in Virginia have been and remain regulated. Alternative energy sources such as electricity, oil, propane and other fuels indirectly impact LGE's natural gas revenues. Marketers may also compete to sell natural gas to certain large end-users. LGE's natural gas tariffs include gas price pass-through mechanisms relating to its sale of natural gas as a commodity. Therefore, customer natural gas purchases from alternative suppliers do not generally impact LGE's profitability. Some large industrial and commercial customers, however, may physically bypass LGE's facilities and seek delivery service directly from interstate pipelines or other natural gas distribution systems. Power Supply At December 31, 2022, LGE owned generating capacity of 2,760 MW and KU owned generating capacity of 4,775 MW. See "Item 2. Properties - Kentucky Regulated Segment" for a complete list of generating facilities. The system capacity of LGE's and KU's owned generation is based upon several factors, including the operating experience and physical condition of the units, and may be revised periodically to reflect changes in circumstances. During 2022, LGE's and KU's power plants generated the following amounts of electricity: ##TABLE_START GWh Fuel Source LGE KU Coal 10,488 13,880 Oil 6 Gas 1,816 5,039 Hydro 278 61 Solar 8 12 Total (a) 12,590 18,998 ##TABLE_END(a) This generation represents an increase for LGE of 5% and a decrease for KU of 1% from 2021 output. The majority of LGE's and KU's generated electricity was used to supply their retail customer bases. LGE and KU jointly dispatch their generation units with the lowest cost generation used to serve their customers. When LGE has excess generation capacity after serving its own customers and its generation cost is lower than that of KU, KU purchases electricity from LGE and vice versa. Due to environmental requirements and energy efficiency measures, as of December 31, 2022, LGE and KU have retired approximately 1,200 MW of coal-fired generation plants since 2010. LGE and KU received approval from the KPSC to develop a 4 MW Solar Share facility to service a Solar Share program. The Solar Share program is a voluntary program that allows customers to subscribe capacity in the Solar Share facility. Construction commences, in 500-kilowatt phases, when subscription is complete. Construction of five 500-kilowatt phases was completed as of December 31, 2022. LGE and KU continue to market the program and have started receiving subscriptions for the sixth 500-kilowatt phase. On January 23, 2020, LGE and KU applied to the KPSC for approval of arrangements relating to the purchase of 100 MW of solar power in connection with the Green Tariff option established in the 2018 Kentucky base rate cases. Pursuant to the agreements, LGE and KU would purchase the initial 20 years of output of a proposed third-party solar generation facility and resell the bulk of the power as renewable energy to two large industrial customers and use the remaining power for other customers. The generation facility is currently expected to be operational in the fourth quarter of 2024. In 2020, the KPSC approved LGEs and KUs applications. PPL, LGE and KU do not anticipate that these arrangements will have a significant impact on their results of operations or financial condition. On October 6, 2021, LGE and KU entered into an agreement to purchase the initial 20 years of output of a proposed 125 MW third-party solar generation facility in connection with the Green Tariff option established in the 2018 Kentucky base rate cases. Pursuant to the agreements, LGE and KU would purchase output of the facility and resell power as renewable energy to certain large customers. The generation facility is currently expected to be operational in the fourth quarter of 2024. PPL, LGE and KU do not anticipate that this agreement will have a significant impact on their results of operations or financial condition. On December 15, 2022, LGE and KU filed an application with the KPSC for a CPCN for the construction of two 621 MW net summer rating NGCC combustion turbine facilities, one at LGE's Mill Creek Generating Station in Jefferson County, Kentucky and the other at KU's E.W. Brown Generating Station in Mercer County, Kentucky, including on-site natural gas and electric transmission construction associated with those facilities and site compatibility certificates. LGE and KU also applied for a CPCN to construct a 120 MWac solar photovoltaic electric generating facility in Mercer County, Kentucky, and for a CPCN to acquire a 120 MWac solar facility to be built by a third-party solar developer in Marion County, Kentucky. LGE and KU further applied for a CPCN to construct a 125 MW, 4-hour battery energy storage system facility at KU's E.W. Brown Generating Station and for approval of their proposed 2024-2030 DSM programs. The plan includes adding 14 new, adjusted or expanded energy efficiency programs, which would reduce LGE's and KU's overall need by approximately 100 MW each. Finally, LGE and KU requested a declaratory order to confirm that their entry into non-firm energy-only power-purchase agreements for the output of four solar photovoltaic facilities with a combined capacity of 637 MW does not require KPSC approval and that LGE and KU may recover the costs of the solar PPAs through their fuel adjustment clause mechanisms as previously approved for a prior solar PPA. LGE and KU plan to accrue AFUDC on the constructed NGCCs, solar facility in Mercer County, Kentucky and the battery energy storage system facility and have requested regulatory asset treatment to recover the financing costs of these projects. The new NGCC would be jointly owned by LGE (31%) and KU (69%) and the solar units would be jointly owned by LGE (37%) and KU (63%), the battery storage unit would be owned by LGE, and the proposed PPA transactions and DSM programs would be entered into or conducted jointly by LGE and KU, consistent with LGE and KU's shared dispatch, cost allocation, tariff or other frameworks. The filing also notes planned retirement dates for certain existing coal-fired generation units, including Mill Creek 1 (300 MW) in 2024 and E.W. Brown 3 (412 MW) in 2028 , and updates and advances the planned retirement dates for Mill Creek 2 (297 MW) to 2027 and Ghent 2 (486 MW) to 2028 . LGE and KU anticipate the recovery of associated retirement costs, including the remaining net book value, for these coal-fired generating units through the RAR or other rate mechanisms. The KPSC accepted the filing as of January 6, 2023 and has indicated its intention to issue an order on all issues by November 6, 2023. LGE and KU cannot predict the outcome of these matters. Fuel Supply Coal and natural gas are expected to be the predominant fuels used by LGE and KU for generation for the foreseeable future. Natural gas used for generation is primarily purchased using contractual arrangements separate from LGE's natural gas distribution operations. Natural gas and oil are also used for intermediate and peaking capacity and flame stabilization in coal-fired boilers. Fuel inventory is maintained at levels estimated to be necessary to avoid operational disruptions at coal-fired generating units. Reliability of coal deliveries can be affected from time to time by several factors including fluctuations in demand, coal mine production issues, high or low river level events, lock outages and other supplier or transporter operating or financial difficulties. LGE and KU have entered into coal supply agreements with various suppliers for coal deliveries through 2027 and augment their coal supply agreements with spot market purchases, as needed. For their existing units, LGE and KU expect, for the foreseeable future, to purchase most of their coal from western Kentucky, southern Indiana, southern Illinois, northern West Virginia and western Pennsylvania. LGE and KU continue to purchase certain quantities of ultra-low sulfur content coal from Wyoming for blending at Trimble County Unit 2. Coal is delivered to the generating plants primarily by barge and rail. To enhance the reliability of natural gas supply, LGE and KU have secured firm long-term pipeline transport capacity services with contracts of various durations through 2024 on the interstate pipeline serving Cane Run Unit 7. This pipeline also serves the six simple cycle combustion turbine units located at the Trimble County site as well as two other simple cycle units at the Paddy's Run site. For the seven simple cycle combustion turbines at the E.W. Brown facility, no firm long-term pipeline transport capacity has been purchased due to the facility's connection to two interstate pipelines and some of the units having dual fuel capability. LGE and KU have firm contracts for a portion of the natural gas fuel for Cane Run Unit 7 through October 2024. The bulk of the natural gas fuel remains purchased on the spot market. (PPL and LGE) Natural Gas Distribution Supply Five underground natural gas storage fields, with a current working natural gas capacity of approximately 15 billion cubic feet (Bcf), are used to provide natural gas service to LGE's firm sales customers. Natural gas is stored during the summer season for withdrawal during the following winter heating season. Without this storage capacity, LGE would need to purchase additional natural gas and pipeline transportation services during winter months when customer demand increases and the cost of natural gas supply and pipeline transportation services are expected to be higher. At December 31, 2022, LGE had 10 Bcf of natural gas stored underground with a carrying value of $68 million. LGE will continue work in 2023 on a multi-year project to retire one of its underground natural gas storage fields with a working natural gas capacity of 4 Bcf, with plans to complete by no later than 2025. LGE has a portfolio of supply arrangements of varying durations and terms that provide competitively priced natural gas designed to meet its firm sales obligations. These natural gas supply arrangements include pricing provisions that are market-responsive. In tandem with pipeline transportation services, these natural gas supplies provide the reliability and flexibility necessary to serve LGE's natural gas customers. LGE purchases natural gas supply transportation services from two pipelines. LGE has a set of contracts with one pipeline that are subject to termination by LGE between 2025 and 2028. Total winter season capacity under these contracts is 184,900 MMBtu/day and summer season capacity is 60,000 MMBtu/day. LGE has two additional contracts with this same pipeline. One contract is for pipeline capacity through 2026 for 60,000 MMBtu/day during both the winter and summer seasons. The other contract is for pipeline capacity through 2028 for 30,000 MMBtu/day during the winter season. LGE has a single contract with a second pipeline with a total capacity of 20,000 MMBtu/day during both the winter and summer seasons that expires in 2030. LGE expects to purchase natural gas supplies for its gas distribution operations from onshore producing regions in South Texas, East Texas, North Louisiana and Arkansas, as well as gas originating in the Marcellus and Utica production areas. (PPL, LGE and KU) Transmission LGE and KU contract with the Tennessee Valley Authority to act as their transmission reliability coordinator and contract with TranServ International, Inc. to act as their independent transmission organization. Rates LGE is subject to the jurisdiction of the KPSC and the FERC, and KU is subject to the jurisdiction of the KPSC, the FERC and the VSCC. LGE and KU operate under a FERC-approved open access transmission tariff. LGE's and KU's Kentucky base rates are calculated based on a return on capitalization (common equity, long-term debt and short-term debt) including adjustments for certain net investments and costs recovered separately through other means. As such, LGE and KU generally earn a return on regulatory assets in Kentucky. KU's Virginia base rates are calculated based on a return on rate base (net utility plant plus working capital less accumulated deferred income taxes and miscellaneous deductions). As all regulatory assets and liabilities, except for regulatory assets and liabilities related to the levelized fuel factor, accumulated deferred income taxes, pension and postretirement benefits, and AROs related to certain CCR impoundments, are excluded from the return on rate base utilized in the calculation of Virginia base rates, no return is earned on the related assets. KU's rates to two municipal customers for wholesale power requirements are calculated based on annual updates to a formula rate that utilizes a return on rate base (net utility plant plus working capital less accumulated deferred income taxes and miscellaneous deductions). As all regulatory assets and liabilities, except accumulated deferred income taxes, are excluded from the return on rate base utilized in the development of municipal rates, no return is earned on the related assets. See "Financial and Operational Developments" in "Item 7. Combined Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 7 to the Financial Statements for additional information on current rate proceedings and rate mechanisms. Pennsylvania Regulated Segment (PPL) The Pennsylvania Regulated segment consists of PPL Electric, a regulated public utility engaged in the distribution and transmission of electricity. (PPL and PPL Electric) PPL Electric delivers electricity to approximately 1.5 million customers in a 10,000-square mile territory in 29 counties within eastern and central Pennsylvania. PPL Electric also provides electricity to retail customers in this territory as a PLR under the Customer Choice Act. See Note 3 to the Financial Statements for revenue information. Franchise, Licenses and Other Regulations PPL Electric is authorized to provide electric public utility service throughout its service area as a result of grants by the Commonwealth of Pennsylvania in corporate charters to PPL Electric and companies that it has succeeded, and as a result of certification by the PAPUC. PPL Electric is granted the right to enter the streets and highways by the Commonwealth subject to certain conditions. In general, such conditions have been met by ordinance, resolution, permit, acquiescence or other action by an appropriate local political subdivision or agency of the Commonwealth. Competition Pursuant to authorizations from the Commonwealth of Pennsylvania and the PAPUC, PPL Electric operates a regulated distribution monopoly in its service area. Accordingly, PPL Electric does not face competition in its electricity distribution business. Pursuant to the Customer Choice Act, generation of electricity is a competitive business in Pennsylvania, and PPL Electric does not own or operate any generation facilities. The PPL Electric transmission business, operating under a FERC-approved PJM Open Access Transmission Tariff, is subject to competition pursuant to FERC Order 1000 from entities that are not incumbent PJM transmission owners with respect to the construction and ownership of transmission facilities within PJM. Rates and Regulation Transmission PPL Electric's transmission facilities are within PJM, which operates the electricity transmission network and electric energy market in the Mid-Atlantic and Midwest regions of the U.S. PJM serves as a FERC-approved Regional Transmission Operator (RTO) to promote greater participation and competition in the region it serves. In addition to operating the electricity transmission network, PJM also administers regional markets for energy, capacity and ancillary services. A primary objective of any RTO is to separate the operation of, and access to, the transmission grid from market participants that buy or sell electricity in the same markets. Electric utilities continue to own the transmission assets and to receive their share of transmission revenues, but the RTO directs the control and operation of the transmission facilities. Certain types of transmission investments are subject to competitive processes outlined in the PJM tariff. As a transmission owner, PPL Electric's transmission revenues are recovered through PJM and billed in accordance with a FERC-approved Open Access Transmission Tariff that allows recovery of incurred transmission costs, a return on transmission-related plant and an automatic annual update based on a formula-based rate recovery mechanism. Under this formula, rates are put into effect in June of each year based upon prior year actual expenditures and current year forecasted capital additions. Rates are then adjusted the following year to reflect actual annual expenses and capital additions, as reported in PPL Electrics annual FERC Form 1, filed under the FERCs Uniform System of Accounts. Any difference between the revenue requirement in effect for the prior year and actual expenditures incurred for that year is recorded as a regulatory asset or regulatory liability. Any change in the prior year PPL zonal peak load billing factor applied on January 1 of each year will result in an increase or decrease in revenue until the next annual rate update is effective on June 1 of that same year. As a PLR, PPL Electric also purchases transmission services from PJM. See "PLR" below. See "Financial and Operational Developments" in "Item 7. Combined Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 7 to the Financial Statements for additional information on rate mechanisms and regulatory matters. Distribution PPL Electric's distribution base rates are calculated based on a return on rate base (net utility plant plus a cash working capital allowance less plant-related deferred taxes and other miscellaneous additions and deductions). All regulatory assets and liabilities, except accumulated deferred income taxes, are excluded from the return on rate base. Therefore, no return is earned on the related assets unless specifically provided for by the PAPUC. Currently, PPL Electric's Smart Meter rider and the DSIC are the only riders authorized to earn a return. Certain operating expenses are also included in PPL Electric's distribution base rates including wages and benefits, other operation and maintenance expenses, depreciation and taxes. Pennsylvania's Alternative Energy Portfolio Standard (AEPS) requires electric distribution companies and electricity generation suppliers to obtain from alternative energy resources a portion of the electricity sold to retail customers in Pennsylvania. Under the default service procurement plans approved by the PAPUC, PPL Electric purchases all of the alternative energy generation supply it needs to comply with the AEPS. Act 129 created an energy efficiency and conservation program, a demand side management program, smart metering technology requirements, new PLR generation supply procurement rules, remedies for market misconduct and changes to the existing AEPS. Act 11 authorizes the PAPUC to approve two specific ratemaking mechanisms: the use of a fully projected future test year in base rate proceedings and, subject to certain conditions, the use of a DSIC. Such alternative ratemaking procedures and mechanisms provide opportunity for accelerated cost-recovery and, therefore, are important to PPL Electric as it is in a period of significant capital investment to maintain and enhance the reliability of its delivery system, including the replacement of aging assets. PPL Electric utilized the fully projected future test year mechanism in its 2015 base rate proceeding. PPL has had the ability to utilize the DSIC recovery mechanism since July 2013. See Note 7 to the Financial Statements for additional information on rate mechanisms and legislative and regulatory matters. PLR The Customer Choice Act requires electric distribution companies, including PPL Electric, or an alternative supplier approved by the PAPUC, to act as a PLR of electricity supply for customers who do not choose to shop for supply with a competitive supplier and provides that electricity supply costs will be recovered by the PLR pursuant to PAPUC regulations. In 2022, the following average percentages of PPL Electric's customer load were provided by competitive suppliers: 37% of residential, 76% of small commercial and industrial and 95% of large commercial and industrial customers. PPL Electrics electricity generation costs are established based upon the results of a competitive solicitation process. In December 2020, the PAPUC approved PPL Electrics default service plan for the period June 1, 2021 through May 31, 2025, which includes a total of eight solicitations for electricity supply held semiannually in April and October. Through December 31, 2022, four auctions of the plan were completed. This plan also includes eight solicitations for alternative energy credits held semiannually in January and July. Through January 2023, four alternative energy credit solicitations have been completed.

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Pursuant to the plans, PPL Electric contracts for all of the electricity supply for residential, commercial and industrial customers who elect to take default service from PPL Electric. These solicitations contain a mix of products including 5-year block energy contracts for residential customers, 6- and 12-month fixed-price load-following contracts for residential and small commercial and industrial customers, 12-month real-time pricing contracts for large commercial and industrial customers, and alternative energy credit contracts for residential, commercial and industrial customers. These contracts fulfill PPL Electric's obligation to provide customer electricity supply as a PLR. Numerous alternative suppliers have offered to provide generation supply in PPL Electric's service area. As the cost of generation supply is a pass-through cost for PPL Electric, its financial results are not impacted if its customers purchase electricity supply from these alternative suppliers. Rhode Island Regulated Segment (PPL) The Rhode Island Regulated segment consists primarily of the regulated electricity transmission and distribution operations and regulated distribution and sale of natural gas conducted by RIE. RIE is engaged in the regulated transmission, distribution and sale of electricity and regulated distribution and sale of natural gas in Rhode Island. RIE provides electric service to approximately 480,000 customers and natural gas service to approximately 270,000 customers. RIE's service area covers substantially all of Rhode Island. See Note 3 to the Financial Statements for revenue information. Franchises and Licenses RIE provides electricity delivery service and natural gas distribution service in its service territory pursuant to certain franchises, licenses, statutory service areas, easements and other rights or permissions granted by the Rhode Island state legislature, cities or municipalities or other entities. Competition There are currently no other electric or gas public utilities operating within the service area of RIE. Alternative energy sources such as electricity, oil, propane and other fuels indirectly impact RIE's natural gas revenues. Marketers may also compete to sell natural gas to certain large end-users. RIE's natural gas tariffs include gas price pass-through mechanisms relating to its sale of natural gas as a commodity. Therefore, customer natural gas purchases from alternative suppliers do not generally impact RIE's profitability. Some large industrial and commercial customers, however, may physically bypass RIE's facilities and seek delivery service directly from interstate pipelines or other natural gas distribution systems. Rates and Regulation In general, RIE operates subject to the jurisdiction of the FERC, the RIPUC and the Rhode Island Division of Public Utilities and Carriers. Distribution RIE owns and maintains electric and natural gas distribution networks in Rhode Island. Distribution revenues are primarily from the sale of electricity, natural gas, and related services to retail customers. Distribution sales are regulated by the RIPUC, which is responsible for approving the rates and other terms of services as part of the rate making process. Natural gas and electric distribution revenues are derived from the regulated sale and distribution of electricity and natural gas to residential, commercial, and industrial customers within RIEs service territory under the tariff rates. The tariff rates approved by the RIPUC are designed to recover the costs incurred by RIE for products and services provided, along with a return on investment. Transmission RIE owns an electric transmission system in Rhode Island. RIEs transmission services are regulated by the FERC and coordinated with ISO New England. Additionally, RIE makes available its transmission facilities to NEP, for operation and control pursuant to an integrated facilities agreement, Service Agreement No. 23 (Integrated Facilities Agreement or IFA). These revenues arise under tariff/rate agreements. Deferral Mechanisms RIE records revenues in accordance with accounting principles for rate-regulated operations for arrangements between RIE and the applicable regulator. These include various deferral mechanisms such as capital trackers, energy efficiency programs, and other programs that qualify as Alternative Revenue Programs (ARPs). ARPs enable RIE to adjust rates in the future, in response to past activities or completed events. RIEs electric and gas distribution rates both have a revenue decoupling mechanism, which allows for annual adjustments to the RIEs delivery rates, as a result of the reconciliation between allowed revenue and billed revenue. RIE also has other ARPs related to the achievement of certain objectives, demand side management initiatives, and certain other rate making mechanisms. RIE recognizes ARPs with a corresponding offset to a regulatory asset or liability account when the regulatory specified events or conditions have been met, when the amounts are determinable, and are probable of recovery (or payment) through future rate adjustments. At December 31, 2022, all of RIEs regulatory assets are authorized to earn a rate of return except $98 million of environmental response costs, $77 million of postretirement benefits and $61 million of net metering deferral costs. Last Resort Service RIE is required by the RIPUC and by statute to provide Last Resort Service. Last Resort Service is available to all customers who have not elected to receive their electric supply from a non-regulated power producer or any customer who, for any reason, has stopped receiving generation service from a non-regulated power producer. The charge for Last Resort Service is the sum of the applicable Last Resort Service charges in addition to all appropriate Retail Delivery charges as stated in the applicable tariff. The monthly charge for Last Resort Service also includes the costs incurred by RIE to comply with the Renewable Energy Standard, established in Rhode Island General Laws Section 39-26-1 and the costs to comply with the RIPUCs Rules Governing Energy Source Disclosure. The charge for Last Resort Service includes the administrative costs associated with the procurement of Last Resort Service, including an adjustment for uncollectible accounts as approved by the RIPUC. Numerous alternative suppliers have offered to provide generation supply in RIE's service area. As the cost of generation supply is a pass-through cost for RIE, its financial results are not impacted if its customers purchase electricity supply from these alternative suppliers. See Note 7 to the Financial Statements for additional information on rate mechanisms and regulatory matters. Natural Gas Distribution Supply To meet the projected annual gas supply requirements of approximately 37 Bcf, RIE has a portfolio of gas supply arrangements of varying contractual terms and durations to provide service to its customers. These natural gas supply arrangements include contracts with natural gas producers and marketers that reflect market price signals. RIE also has firm pipeline and underground storage capacity contracts to support the delivery of natural gas supplies to its customers. To manage the winter peak requirements for RIE customers, RIE contracts for liquified natural gas (LNG) service and owns and operates certain LNG storage facilities. The RIE gas supply portfolio includes contracts for firm transportation service with eleven interstate pipeline companies and natural gas storage operators. These contracts have various termination dates with certain contracts being subject to evergreen renewal provisions providing RIE with flexibility in managing its upstream resource portfolio. RIE has purchased and expects to continue to purchase natural gas supplies for its gas distribution operations from onshore producing regions accessed by its pipeline capacity portfolio in South Texas, East Texas, and Louisiana, as well as gas originating in the Marcellus and Utica production areas. RIE expects to purchase certain natural gas supplies that originate in Canada and from regional LNG import terminals. Corporate and Other (PPL) PPL Services provides PPL subsidiaries with administrative, management and support services. The costs of these services are charged directly to the respective recipients for the services provided or indirectly charged to applicable recipients based on an average of the recipients' relative invested capital, operation and maintenance expenses and number of employees or a ratio of overall direct and indirect costs. PPL Capital Funding provides financing for the operations of PPL and certain subsidiaries. PPL's growth in rate-regulated businesses provides the organization with an enhanced corporate level financing alternative, through PPL Capital Funding, that enables PPL to cost effectively support targeted credit profiles across all of PPL's rated companies. As a result, PPL utilizes PPL Capital Funding as a source of capital in financings, in addition to continued direct financing by certain operating subsidiaries. Unlike those of PPL Services, PPL Capital Funding's costs are not generally charged to PPL subsidiaries. Costs are charged directly to PPL. However, PPL Capital Funding participated significantly in the financing for the acquisition of LKE and certain associated financing costs were allocated to the Kentucky Regulated Segment. Prior to 2021, the associated financing costs, as well as the financing costs associated with prior issuances of certain other PPL Capital Funding securities, were assigned to the relevant segments for purposes of PPL management's assessment of segment performance. Beginning in 2021, corporate level financing costs are no longer allocated to the reportable segments. ENVIRONMENTAL MATTERS (All Registrants) The Registrants are subject to certain existing and developing federal, regional, state and local laws and regulations with respect to air and water quality, land use and other environmental matters, and may be subject to different and more stringent such laws and regulations enacted in the future. The EPA and other federal agencies with jurisdiction over environmental matters have issued numerous environmental regulations relating to air, water and waste that directly affect the electric power industry. Due to these environmental issues, it may be necessary for the Registrants to modify or cease certain operations or operation of certain facilities to comply with statutes, regulations and other requirements of regulatory bodies or courts. In addition, legal challenges to environmental permits or rules add uncertainty to estimating future costs of complying with such permits and rules. The Biden administration is currently undertaking changes in a wide range of environmental programs. See Legal Matters in Note 14 to the Financial Statements for a discussion of environmental commitments and contingencies. See "Financial Condition - Liquidity and Capital Resources - Forecasted Uses of Cash - Capital Expenditures" in "Item 7. Combined Management's Discussion and Analysis of Financial Condition and Results of Operations" for information on projected environmental capital expenditures for 2023 through 2025. See Note 20 to the Financial Statements for information related to the impacts of CCRs on AROs. LGE and KU are entitled to recover, through the ECR mechanism, certain costs of complying with the Clean Air Act, as amended, and other federal, state and local environmental requirements applicable to coal combustion wastes and by-products from coal-fired generating facilities upon KPSC review. Costs not covered by the ECR mechanism for LGE and KU and all such costs for PPL Electric are subject to rate recovery at the discretion of the companies' respective state regulatory authorities, or the FERC, if applicable. Because PPL Electric and RIE do not own any generating plants, they have less exposure to related environmental compliance costs. The Registrants can provide no assurances as to the ultimate outcome of future proceedings before regulatory authorities. Air NAAQS (PPL, LGE and KU) Applicable regulations require each state to identify areas within its boundaries that fail to meet the NAAQS, (known as nonattainment areas), and develop a state implementation plan to achieve and maintain compliance. States that are found to contribute significantly to another state's nonattainment with ozone standards are required to establish "good neighbor" state implementation plans. In addition, for attainment of ozone and fine particulates standards, certain states, including Kentucky, are subject to a regional EPA program known as the Cross-State Air Pollution Rule (CSAPR). The Clean Air Act has a significant impact on the operation of fossil fuel generation plants. The Clean Air Act requires the EPA periodically to establish and review NAAQS for six pollutants: carbon monoxide, lead, nitrogen dioxide, ozone (contributed to by nitrogen oxide emissions), particulate matter and sulfur dioxide. In December 2020, the EPA released final actions keeping the existing NAAQS standard for particulate matter and ozone without change, but the EPA subsequently announced reconsideration of those decisions in June 2021. On January 6, 2023, the EPA released a pre-publication proposed revision to the particulate matter standard that would lower the primary standard for fine particulates to a level to be determined after review of additional public comments. Depending on the final standard adopted by the EPA, the EPA could potentially designate Jefferson County, Kentucky (Louisville) as being in nonattainment with the new particulate matter standard and require additional particulate matter reductions from sources including LGEs Mill Creek Station. PPL, LGE, and KU are unable to predict the outcome of future evaluations by the EPA and the states with respect to the NAAQS standards. In January 2018, the EPA designated Jefferson County, Kentucky (Louisville) as being in nonattainment with the existing 2015 ozone standard. In 2020 and 2021, LGE entered into agreements with the Louisville Metro Air Pollution Control District for temporary nitrogen oxide emission limits at LGE's

Mill Creek Station during those years to facilitate compliance with the ozone standard. In October 2022, Jefferson County was bumped up to the moderate nonattainment classification, but the Louisville Air Pollution Control District has applied to the EPA for Jefferson County to be redesignated as in attainment. Although PPL and LGE expect Jefferson County to be redesignated as in attainment, if the EPA declines to issue such a redesignation, Jefferson County could be subject to additional requirements including requirements for installation of reasonably available control technology on coal-fired generating units. Compliance with such requirements may require installation of additional pollution controls or other compliance actions. PPL and LGE are unable to determine the impact on operations until certain compliance determinations are made by the EPA and Kentucky. In March 2021, the EPA released final revisions to the CSAPR, aimed at ensuring compliance with the 2008 ozone NAAQS and providing for reductions in ozone season nitrogen oxide emissions for 2021 and subsequent years from sources in 12 states, including Kentucky. Additionally, the EPA reversed its previous approval of the Kentucky State Implementation Plan with respect to these requirements. In February 2022, the EPA Administrator released a proposed Federal Implementation Plan under the Good Neighbor provisions of the Clean Air Act providing for significant additional nitrogen oxide emission reductions for compliance with the revised 2015 ozone NAAQS. The proposed reductions in Kentucky state-wide nitrogen oxide budgets are scheduled to commence in 2023, with the largest reductions planned for 2026, based on the installation time frame for certain selective catalytic reduction controls, subject to future specific allowance calculations. PPL, LGE and KU are currently assessing the potential impact of the proposed Good Neighbor Plan revisions on operations. The current and proposed rules provide for reduced availability of nitrogen oxide allowances that have historically permitted operational flexibility for fossil units and could potentially result in constraints that may require implementation of additional emission controls or accelerate implementation of lower emission generation technologies. Pursuant to the Presidents executive order, the EPA is currently reviewing its previous determinations made in December 2020 to retain the existing NAAQS for ozone and particulate matter without change, including a pre-publication proposed revision that was released by the EPA on January 6, 2023. PPL, LGE, and KU are unable to predict future emission reductions that may be required by future federal rules or state implementation actions. Compliance with the NAAQS, CSAPR and related requirements may require installation of additional pollution controls or other compliance actions, inclusive of retirements, the costs of which PPL, LGE and KU believe would be subject to rate recovery. Climate Change (All Registrants) The Biden administration is undertaking wide-ranging efforts to address climate change. Recent government actions and policy developments, including the Presidents announced goal of a carbon free electricity sector by 2035, could have far-reaching impacts on PPLs business operations, products, and services. On June 30, 2022, the Supreme Court ruled that provisions of the EPA's Clean Power Plan, premised on generation shifting from coal-fired plants to lower emitting natural gas-fired plants and renewables, exceeded the authority granted to the EPA under the Clean Air Act. The EPA has announced that it plans on issuing new greenhouse gas rules in the future. It is uncertain how the Supreme Court ruling may impact future EPA rulemaking. All of these developments are preliminary or ongoing in nature and the Registrants cannot predict the final outcome or ultimate impact on operations. PPL has adopted a goal of net-zero carbon emissions by 2050, which PPL expects will include continuing to retire coal-fired generation and investing in research and innovation that will help to achieve this goal, while maintaining reliable and affordable energy in our service territories. The net-zero goal relates to direct and indirect carbon emissions consistent with Greenhouse Gas Protocol guidance and referenced by the EPA Center for Corporate Climate Leadership. Through 2021, PPL reduced carbon emissions nearly 60% from 2010 levels and is targeting a 70% reduction from 2010 levels by 2035 and an 80% reduction by 2040. PPL is also aware of the various risks associated with climate change, including increased frequency and severity of severe weather. To address these risks, PPL continues to work to advance grid modernization and improve the Company's equipment to help mitigate the impacts of extreme weather events and improve reliability. Water/Waste (PPL, LGE and KU) Clean Water Act Regulations under the federal Clean Water Act dictate permitting and mitigation requirements for facilities and construction projects that impact "Waters of the United States". Many other requirements relate to power plant operations, including the treatment of pollutants in effluents prior to discharge, the temperature of effluent discharges and the location, design and construction of cooling water intake structures at generating facilities, and standards intended to protect aquatic organisms that become trapped at or pulled through cooling water intake structures at generating facilities. These requirements could impose significant costs for LGE and KU, which are expected to be subject to rate recovery. Clean Water Act Jurisdiction Environmental groups and others have claimed that discharges to groundwater from leaking CCR impoundments at power plants are subject to Clean Water Act permitting. On April 12, 2019, the EPA released regulatory clarification finding that Clean Water Act jurisdiction does not cover such discharges to groundwater. On January 23, 2020, the EPA announced a final rule modifying the jurisdictional scope of the Clean Water Act. The announced rule revises the definition of the "Waters of the United States," including a revision to exclude groundwater from the definition. In April 2020, the U.S. Supreme Court issued a ruling that Clean Water Act jurisdiction may apply to certain discharges to groundwater that result in the functional equivalent of a direct discharge to navigable waters. PPL, LGE, and KU are unaware of any unpermitted releases from their facilities that are subject to Clean Water Act jurisdiction, but future regulatory developments and judicial rulings could potentially subject certain releases from CCR impoundments and landfills to additional permitting and remediation requirements, which could impose substantial costs. Any associated costs are expected to be subject to rate recovery. PPL, LGE and KU are unable to predict the outcome or financial impact of future regulatory proceedings and litigation. Waters of the United States PPL, LGE, and KU are subject to permitting and mitigation requirements for certain construction activities that impact "Waters of the United States." On April 21, 2020, the EPA and U.S. Army Corps of Engineers published a final rule revising the definition of "Waters of the United States" to exclude jurisdiction over certain surface waters. On August 30, 2021, a U.S. District Court in Arizona vacated and remanded the rule. On December 7, 2021, the EPA and U.S. Army Corps of Engineers proposed to repeal the rule and restore the definition of "Waters of the United States" that was in place prior to 2015. On January 24, 2022, the U.S. Supreme Court granted review of a case raising the issue of the appropriate scope of the definition of "Waters of the United States" under the Clean Water Act. On January 18, 2023, the EPA and U.S. Army Corps of Engineers published a final revision to the rule broadening the definition of Waters of the United States and reverting to the pre-2015 regulatory framework. Although the broader definition incorporates additional water bodies, any resulting permitting, construction, and operational expenses are expected to be immaterial and subject to rate recovery. PPL, LGE and KU are unable to predict the outcome of current or future litigation or regulatory proceedings, but do not expect a material impact on operations. Superfund and Other Remediation (All Registrants) From time to time, PPL's subsidiaries undertake testing, monitoring or remedial action in response to spills or other releases at various on-site and off-site locations, negotiate with the EPA and state and local agencies regarding actions necessary to comply with applicable requirements, negotiate with property owners and other third parties alleging impacts from PPL's operations and undertake similar actions necessary to resolve environmental matters that arise in the course of normal operations. Based on analyses to date, resolution of these environmental matters is not expected to have a significant adverse impact on the operations of PPL, PPL Electric, LGE and KU. Future cleanup or remediation work at sites not yet identified may result in significant additional costs for the Registrants. Insurance policies maintained by LGE and KU may be available to cover certain of the costs or other obligations related to these matters, but the amount of insurance coverage or reimbursement cannot be estimated or assured. See Legal Matters in Note 14 to the Financial Statements for additional information. (All Registrants) SEASONALITY The demand for and market prices of electricity and natural gas are affected by weather. As a result, the Registrants' operating results in the future may fluctuate substantially on a seasonal basis, especially when unpredictable weather conditions make such fluctuations more pronounced. The pattern of this fluctuation may change depending on the type and location of the facilities owned. FINANCIAL CONDITION See "Financial Condition" in "Item 7. Combined Management's Discussion and Analysis of Financial Condition and Results of Operations" for this information. CAPITAL EXPENDITURE REQUIREMENTS See "Financial Condition - Liquidity and Capital Resources - Forecasted Uses of Cash - Capital Expenditures" in "Item 7. Combined Management's Discussion and Analysis of Financial Condition and Results of Operations" for information concerning projected capital expenditure requirements for 2023 through 2025. See "Item 1. Business - Environmental Matters" for additional information concerning the potential impact on capital expenditures from environmental matters. HUMAN CAPITAL PPL, together with its subsidiaries, is committed to fostering an exceptional workplace for employees. PPL pledges to enable the success of its current and future workforce by cultivating a diverse, equitable and inclusive culture, fostering professional development, encouraging employee engagement, and ensuring a safe and healthy work environment. Matters related to these priorities and corporate culture are overseen by PPL's senior management, which provides updates to the PPL Board of Directors (the Board). Pursuant to its charter, the Compensation Committee of the Board of Directors also periodically reviews and assesses the Company's strategy for human capital management. PPL's investment in the success of our workforce is embodied in the following areas with dedicated leadership and Board oversight: Diversity, equity and inclusion (DEI) - Foster an inclusive, respectful and diverse workplace through a comprehensive DEI strategy and commitments. PPL created a chief diversity officer position in 2022 to lead the company's DEI efforts. Senior management reviews demographic metrics, DEI objectives and associated programs semi-annually. The Board also receives periodic updates from senior management on PPL's DEI strategy and initiatives. Employee engagement - Create a workplace that fosters an engaged, high-quality workforce. PPL's operating companies regularly conduct assessments related to employee engagement, safety and culture. Senior management reviews corporate culture with the Board annually. Professional development - Invest in our current and future workforce through training and development, succession planning and creation of a pipeline for internal advancement. Senior management reviews succession planning with the Compensation Committee of the Board on an annual basis. Comprehensive benefits - In addition to challenging careers and competitive salaries, PPL offers competitive benefits programs to attract and retain talent and support employees' well-being. PPL offers competitive vacation time, expanded leave for new parents, retirement programs, and internal and external development opportunities, including tuition reimbursement offerings for undergraduate and certain graduate degrees. Senior management conducts annual benchmarking of employee compensation and benefits. Safety and Compliance - PPL is also committed to maintaining an ethical and safe workplace culture. Additional steps to ensure Board oversight in these areas include: Safety PPL carries out programs focused on health and safety, including emergency preparedness, vehicle safety and accident prevention. Employees receive safety training and are encouraged to share, implement, and follow best practices. Senior management receives monthly safety data updates to determine whether additional safety measures should be implemented. The Board annually reviews the company's safety programs and results. The Board is also immediately engaged in the event of a fatality. Compliance The Corporate Compliance Committee, including senior executives, meets quarterly to discuss metrics and other matters related to the compliance and ethics culture. Among the items discussed are statistics regarding Ethics Helpline reports and employee concerns. This information is also reviewed with the Audit Committee of the Board quarterly. PPL will continue to engage with employees and to assess these priorities as we work to best position individuals and the company for future success. PPL had a turnover rate of 10.7% for the year ended December 31, 2022. Looking forward, we will maintain our strong focus on workforce planning to address future talent needs. At December 31, 2022, PPL and its subsidiaries had the following full-time employees and employees represented by labor unions: ##TABLE_START Total Full-Time Employees Number of Union Employees Percentage of Total Workforce PPL 6,527 2,411 37 % PPL Electric 1,382 913 66 % LGE 964 618 64 % KU 807 109 14 % ##TABLE_END(PPL and PPL Electric) In March 2022, members of the IBEW Local 1600 ratified a new five-year labor agreement with PPL and PPL Electric. The contract covers over 900 employees and was effective May 16, 2022. The current five-year agreement expires in May 2027. The terms of the new labor agreement are not expected to have a significant impact on the financial results of PPL or PPL Electric. (PPL and KU) Labor agreement negotiations with the KU USW are expected to commence in July 2023. The current contract covers over 40 employees and is scheduled to expire in August 2023. (PPL and LGE) Labor agreement negotiations with the LGE IBEW are expected to commence in October 2023. The current contract covers over 600 employees and is scheduled to expire in November 2023. CYBERSECURITY MANAGEMENT The Registrants and their subsidiaries are subject to risks from cyber-attacks that have the potential to cause significant interruptions to the operation of their businesses. The frequency of these attempted intrusions has increased in recent years and the sources, motivations and techniques of attack continue to evolve and change rapidly. PPL has adopted a variety of measures to monitor and address cyber-related risks and continues to implement and explore additional cybersecurity measures. Cybersecurity and the effectiveness of PPL's cybersecurity strategy are regular topics of discussion at Board of Directors meetings. PPL's strategy for managing cyber-related risks is risk-based and, where appropriate, integrated within PPL's enterprise risk management processes. PPL's Vice President and Chief Security Officer (CSO), who reports directly to the President and Chief Executive Officer (CEO), leads a dedicated cybersecurity team and is responsible for the design, implementation, and execution of cyber-risk management strategy. In addition, among other things, the CSO and the cybersecurity team actively monitor the Registrants' systems, regularly review policies, compliance, regulations and best practices, perform penetration testing, conduct incident response exercises and internal ethical phishing campaigns, and provide training and communication across the organization to strengthen secure behavior and foster a culture of security. The cybersecurity team also routinely participates in industry-wide programs to further information sharing, intelligence gathering, and unity of effort in responding to potential or actual attacks. In addition, PPL has a formal internal policy and procedures for communicating cybersecurity incidents on an enterprise-wide basis. In addition to these enterprise-wide initiatives, PPL's Kentucky, Pennsylvania and Rhode Island operations are subject to extensive and rigorous mandatory cybersecurity requirements that are developed and enforced by NERC and approved by the FERC to protect grid security and reliability. LGE is also subject to certain security directives related to cybersecurity issued by the Department of Homeland Securitys Transportation Security Administration in 2021. See Note 14 to the Financial Statements for additional information on these directives. Finally, PPL purchases insurance to protect against a wide range of costs that could be incurred in connection with cyber-related incidents. There can be no assurance, however, that these efforts will be effective to prevent interruption of services or other damage to the Registrants' businesses or operations or that PPL's insurance coverage will cover all costs incurred in connection with any cyber-related incident. AVAILABLE INFORMATION PPL's Internet website is www.pplweb.com. Under the Investors heading of that website, PPL provides access to SEC filings of the Registrants (including annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to these reports filed or furnished pursuant to Section 13(d) or 15(d)) free of charge, as soon as reasonably practicable after filing with the SEC. The information contained on, or available through, PPL's Internet website is not, and shall not be deemed to be, incorporated by reference into this report. Additionally, the Registrants' filings are available at the SEC's website (www.sec.gov). ITEM 1A. RISK FACTORS The Registrants face various risks associated with their businesses. Our businesses, financial condition, cash flows or results of operations could be materially adversely affected by any of these risks. In addition, this report also contains forward-looking and other statements about our businesses that are subject to numerous risks and uncertainties. See "Forward-Looking Information," "Item 1. Business," "Item 7. Combined Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 14 to the Financial Statements for additional information concerning the risks described below and for other risks, uncertainties and factors that could impact our businesses and financial results. As used in this Item 1A., the terms "we," "our" and "us" generally refer to PPL and its consolidated subsidiaries taken as a whole, or PPL Electric and its consolidated subsidiaries taken as a whole within the Pennsylvania Regulated segment discussion, LKE and its consolidated subsidiaries taken as a whole within the Kentucky Regulated segment discussion, and RIE and its consolidated subsidiaries taken as a whole within the Rhode Island Regulated segment discussion. Order of Subsection Presentation A. Risks Related to Registrant Holding Company B. Risks Related to Regulated Utility Operations C. Risks Specific to Kentucky Regulated Segment D. Risks Specific to Pennsylvania Regulated Segment E. Risks Specific to Rhode Island Regulated Segment F. Risks Related to All Segments (PPL) A. Risk Related to Registrant Holding Company PPL is a holding company and its cash flows and ability to meet its obligations with respect to indebtedness and under guarantees, and its ability to pay dividends, largely depends on the financial performance of its respective subsidiaries and, as a result, is effectively subordinated to all existing and future liabilities of those subsidiaries. PPL is a holding company and conducts its operations primarily through subsidiaries. Substantially all of the consolidated assets of PPL are held by its subsidiaries. Accordingly, PPL's cash flows and ability to meet debt and guaranty obligations, as well as PPL's ability to pay dividends, are largely dependent upon the earnings of those subsidiaries and the distribution or other payment of such earnings in the form of dividends, distributions, loans, advances or repayment of loans and advances. The subsidiaries are separate legal entities and have no obligation to pay dividends or distributions to their parents or to make funds available for such a payment. The ability of PPL's subsidiaries to pay dividends or distributions in the future will depend on the subsidiaries' future earnings and cash flows and the needs of their businesses, and may be restricted by their obligations to holders of their outstanding debt and other creditors, as well as any contractual or legal restrictions in effect at such time, including the requirements of state corporate law applicable to payment of dividends and distributions, and regulatory requirements, including restrictions on the ability of PPL Electric, LGE, KU, and RIE to pay dividends under Section 305(a) of the Federal Power Act. Because PPL is a holding company, its debt and guaranty obligations are effectively subordinated to all existing and future liabilities of its subsidiaries. Although certain agreements to which certain subsidiaries are parties limit their ability to incur additional indebtedness, PPL and its subsidiaries retain the ability to incur substantial additional indebtedness and other liabilities. Therefore, PPL's rights and the rights of its creditors, including rights of debt holders, to participate in the assets of any of its subsidiaries, in the event that such a subsidiary is liquidated or reorganized, will be subject to the prior claims of such subsidiary's creditors. (All Registrants) B. Risks Related to Regulated Utility Operations Our regulated utility businesses face many of the same risks, in addition to those risks that are unique to each of the Kentucky Regulated, Pennsylvania Regulated and Rhode Island Regulated segments. Set forth below are risk factors common to the regulated segments, followed by sections identifying separately the risks specific to each of these segments. Our profitability is highly dependent on our ability to recover the costs of providing energy and utility services to our customers and earn an adequate return on our capital investments. Regulators may not approve the rates we request and existing rates may be challenged. The rates we charge our utility customers must be approved by one or more federal or state regulatory commissions, including the FERC, KPSC, VSCC, PAPUC and RIPUC. Although rate regulation is generally premised on the recovery of prudently incurred costs and a reasonable rate of return on invested capital, there can be no assurance that regulatory authorities will consider all of our costs to have been prudently incurred or that the regulatory process by which rates are determined will always result in rates that achieve full or timely recovery of our costs or an adequate return on our capital investments. Federal or state agencies, intervenors and other permitted parties may challenge our current or future rate requests, structures or mechanisms, and ultimately reduce, alter or limit the rates we receive. Although our rates are generally regulated based on an analysis of our costs incurred in a base year or on future projected costs, the rates we are allowed to charge may or may not match our costs at any given time. Our regulated utility businesses are subject to substantial capital expenditure requirements over the next several years, which may require rate increase requests to the regulators in the future. If our costs are not adequately recovered through rates, it could have an adverse effect on our business, results of operations, cash flows and financial condition. Our utility businesses are subject to significant and complex governmental regulation. In addition to regulating the rates we charge, various federal and state regulatory authorities regulate many aspects of our utility operations, including: the terms and conditions of our service and operations; financial and capital structure matters; siting, construction and operation of facilities; mandatory reliability and safety standards under the Energy Policy Act of 2005 and other standards of conduct; accounting, depreciation and cost allocation methodologies; tax matters; affiliate transactions; acquisition and disposal of utility assets and issuance of securities; and various other matters, including energy efficiency. Such regulations or changes thereto may subject us to higher operating costs or increased capital expenditures and failure to comply could result in sanctions or possible penalties which may not be recoverable from customers. Our regulated businesses undertake significant capital projects and these activities are subject to unforeseen costs, delays or failures, as well as risk of inadequate recovery of resulting costs. The regulated utility businesses are capital intensive and require significant investments in energy generation (in the case of LGE and KU) and transmission, distribution and other infrastructure projects, such as projects for environmental compliance and system reliability. The completion of these projects without delays or cost overruns is subject to risks in many areas, including: approval, licensing and permitting; land acquisition and the availability of suitable land; skilled labor or equipment shortages; construction problems or delays, including disputes with third-party intervenors; increases in commodity prices or labor rates; potential supply chain disruptions or delays; and contractor performance. Failure to complete our capital projects on schedule or on budget, or at all, could adversely affect our financial performance, operations and future growth if such expenditures are not granted rate recovery by our regulators. We are or may be subject to costs of remediation of environmental contamination at facilities owned or operated by our former subsidiaries. We may be subject to liability for the costs of environmental remediation of property now or formerly owned by us with respect to substances that we may have generated regardless of whether the liabilities arose before, during or after the time we owned or operated the facilities. We also have current or previous ownership interests in sites associated with the production of manufactured gas for which we may be liable for additional costs related to investigation, remediation and monitoring of these sites. Remediation activities associated with our former manufactured gas plant operations are one source of such costs. Citizen groups or others may bring litigation regarding environmental issues including claims of various types, such as property damage, personal injury and citizen challenges to compliance decisions on the enforcement of environmental requirements, which could subject us to penalties, injunctive relief and the cost of litigation. We cannot predict the amount and timing of future expenditures (including the potential or magnitude of fines or penalties) related to such environmental matters, although they could be material. C. Risks Specific to Kentucky Regulated Segment (PPL, LGE and KU) We are subject to financial, operational, regulatory and other risks related to requirements, developments and uncertainties in environmental regulation, including those affecting coal-fired generation facilities. Extensive federal, state and local environmental laws and regulations are applicable to LGE's and KU's generation supply, including its air emissions, water discharges (ELGs) and the management of hazardous and solid wastes (CCRs), among other business-related activities, and the costs of compliance or alleged non-compliance cannot be predicted and could be material. In addition, our costs may increase significantly if the requirements or scope of environmental laws, regulations or similar rules are expanded or changed as the environmental standards governing LGEs and KUs businesses, particularly as applicable to coal-fired generation and related activities, continue to be subject to uncertainties due to rulemaking and other regulatory developments, legislative activities and litigation, administrative and permit challenges. The Biden administration is considering a wide range of potential policies, executive orders, rules, legislation and other initiatives in connection with climate change that may affect these costs. Depending on the extent, frequency and timing of such changes, LGE and KU may face higher risks of unsuccessful implementation of environmental-related business plans, noncompliance with applicable environmental rules, delayed or incomplete rate recovery or increased costs of implementation. Costs may take the form of increased capital expenditures or operating and maintenance expenses, monetary fines, penalties or forfeitures, operational changes, permit limitations or other restrictions. At some of our older generating facilities it may be uneconomic for us to install necessary pollution control equipment, which could cause us to retire those units. Market prices for energy and capacity also affect this cost-effectiveness analysis. Many of these environmental law considerations are also applicable to the operations of our key suppliers or customers, such as coal producers, power producers and industrial power users, and may impact the costs of their products and demand for our services. (PPL and LGE) We are subject to operational, regulatory and other risks regarding natural gas supply infrastructure. A natural gas pipeline explosion or associated incident could have a significant impact on LGEs natural gas operations or result in significant damages and penalties that could have an adverse impact on LGEs financial position and results of operations. The Pipeline and Hazardous Materials Safety Administration enforces regulations that govern the design, construction, operation and maintenance of pipeline facilities. Failure to comply with these regulations could result in the assessment of fines or penalties against LGE. These regulations require, among other things, that pipeline operators take certain measures with respect to pipeline integrity. Depending on the results of integrity tests and other integrity program activities, we could incur significant and unexpected costs to perform remedial activities on our natural gas infrastructure to ensure our continued safe and reliable operation. Recent pipeline incidents in the U.S. have also led to the introduction of proposed rules and possible federal legislative actions which could impose restrictions on LGEs operations or require more stringent testing to ensure pipeline integrity. Implementation of these regulations could increase our costs to comply with pipeline integrity and safety regulations. D. Risks Specific to Pennsylvania Regulated Segment (PPL and PPL Electric) We face competition for transmission projects, which could adversely affect our rate base growth. FERC Order 1000, issued in July 2011, establishes certain procedural and substantive requirements relating to participation, cost allocation and non-incumbent developer aspects of regional and inter-regional electricity transmission planning activities. The PPL Electric transmission business, operating under a FERC-approved PJM Open Access Transmission Tariff, is subject to competition pursuant to FERC Order 1000 from entities that are not incumbent PJM transmission owners with respect to the construction and ownership of transmission facilities within PJM. Increased competition can result in lower rate base growth. We could be subject to higher costs and/or penalties related to Pennsylvania Conservation and Energy Efficiency Programs. PPL Electric is subject to Act 129, which contains requirements for energy efficiency and conservation programs and for the use of smart metering technology, imposes PLR electricity supply procurement rules, provides remedies for market misconduct, and made changes to the existing Alternative Energy Portfolio Standard. The law also requires electric utilities to meet specified goals for reduction in customer electricity usage and peak demand. Utilities not meeting these Act 129 requirements are subject to significant penalties that cannot be recovered in rates. Numerous factors outside of our control could prevent compliance with these requirements and result in penalties to us. E. Risks Related to the Rhode Island Regulated Segment (PPL) PPL may not realize the anticipated benefits of the RIE acquisition, which could materially adversely affect PPL's business, financial condition and results of operations. PPL may not realize the anticipated financial and operational benefits from the RIE acquisition if the business is not integrated in an efficient and effective manner or if integration takes longer than anticipated. These integration risks include potential difficulties in conversion of systems and information, difficulties in harmonizing inconsistencies in standards, controls, procedures, practices and policies, disruption from the acquisition making it more difficult to maintain relationships with customers, employees or suppliers, and diversion of management time and attention to integration and other acquisition-related issues. In addition, PPL has incurred, and will continue to incur, significant costs in connection with the integration, and additional unanticipated costs may arise. No assurance can be given that the anticipated benefits from the acquisition will be achieved or, if achieved, the timing of their achievement. These risks and their consequences could result in increased costs or decreases in the amount of expected revenues and could have a material adverse effect on PPL's business, financial condition and results of operations. We are subject to operational, regulatory and other risks regarding natural gas supply infrastructure in Rhode Island. A natural gas pipeline explosion or associated incident could have a significant impact on RIE's natural gas operations or result in significant damages and penalties that could have an adverse impact on RIEs financial position and results of operations. The Pipeline and Hazardous Materials Safety Administration enforces regulations that govern the design, construction, operation and maintenance of pipeline facilities. Failure to comply with these regulations could result in the assessment of fines or penalties against RIE. These regulations require, among other things, that pipeline operators take certain measures with respect to pipeline integrity. Depending on the results of integrity tests and other integrity program activities, we could incur significant and unexpected costs to perform remedial activities on our natural gas infrastructure to ensure our continued safe and reliable operation. F. Risks Related to All Segments (All Registrants) COVID-19 or other pandemics and resultant impact on business and economic conditions could negatively affect our business. The COVID-19 pandemic disrupted the U.S. and global economies. While its impact is waning in many respects, a resurgence, new variant or other pandemic and related remediation efforts could present challenges to businesses, communities, workforces, markets and supply chains. The COVID-19 virus continues to pose risks to the health and welfare of the Registrants customers, employees, contractors and suppliers, and to affect the conduct of their business. The COVID-19 pandemic has been a contributing factor to certain supply chain shortages that have created risks of potential equipment and fuel supply chain disruptions. These issues may continue or become worse, as a result of pandemics and other factors, and Registrants may be forced to rely on a larger pool of suppliers, which could pose operational risks. These factors have the potential to materially and adversely affect the Registrants business and operations, especially if they are exacerbated by a resurgence or other pandemics. At this time, the Registrants cannot predict the extent to which these or other pandemic-related factors may affect their business, earnings or other financial results. Our business operations are continually subject to cyber-based security and data integrity risks from vulnerabilities related to our IT systems, operational technology infrastructure and supply chain relationships. Numerous functions affecting the efficient operation of our businesses are dependent on the secure and reliable storage, processing and communication of electronic data and the use of sophisticated computer hardware and software systems. The operation of our transmission and distribution systems, including gas distribution systems, as well as our generation plants, are all reliant on cyber-based technologies and, therefore, subject to the risk that these systems could be the target of disruptive actions by terrorists, nation state actors or criminals or otherwise be compromised by unintentional events. Attacks may come through ransomware, software updates or patches, use of opensource software, firmware that hackers can manipulate to include malicious codes for exploitation at a later date, or the compromising of hardware by bad actors, creating serious risks to our security, the security of our customers' information, and potentially to our ability to provide power. As a result, operations could be interrupted, property could be damaged and sensitive customer information lost or stolen, causing us to incur significant losses of revenues, other substantial liabilities and damages, costs to replace or repair damaged equipment and damage to our reputation. Threats to our systems and operations continue to emerge as new ways to compromise components of our systems or networks are developed. Additionally, cybersecurity risks also threaten our supply chains, including aspects that are not under our control, such as the incorporation of opensource software in systems or software that we use, that despite our efforts do not meet our current security standards. In addition, under the Energy Policy Act of 2005, users, owners and operators of the bulk power transmission system, including PPL Electric, LGE, KU and RIE, are subject to mandatory reliability standards promulgated by NERC and enforced by the FERC. As an operator of natural gas distribution systems, LGE is also subject to mandatory reliability standards of the U.S. Department of Transportation and is also subject to certain security directives related to cybersecurity issued by the Department of Homeland Security (DHS) Transportation Security Administration (TSA) in 2021. The TSA has determined that LGE is critical, while RIE has not been notified of this distinction and is therefore not currently subject to the security directives. Failure to comply with these standards could result in the imposition of fines or civil penalties, and potential exposure to third party claims for alleged violations of the standards. We are subject to risks associated with federal and state tax laws and regulations. Changes in tax law as well as the inherent difficulty in quantifying potential tax effects of business decisions could negatively impact our results of operations and cash flows. We are required to make judgments in order to estimate our obligations to taxing authorities. These tax obligations include income, property, gross receipts, franchise, sales and use, employment-related and other taxes. We also estimate our ability to utilize deferred tax assets and tax credits. Dependent upon the revenue needs of the jurisdictions in which our businesses operate, various tax and fee increases may be proposed or considered. We cannot predict changes in tax law or regulation or the effect of any such changes on our businesses. Any such changes could increase tax expense and could have a significant negative impact on our results of operations and cash flows. The effects of the TCJA have been reflected in our financial statements, and we continue to evaluate the application of the law in calculating income tax expense. Increases in electricity prices and/or a weak economy can lead to changes in legislative and regulatory policy, including the promotion of energy efficiency, conservation and distributed generation or self-generation, which may adversely impact our business. Energy consumption is significantly impacted by overall levels of economic activity and costs of energy supplies. Economic downturns or periods of high energy supply costs can lead to changes in or the development of legislative and regulatory policy designed to promote reductions in energy consumption and increased energy efficiency, alternative and renewable energy sources, and distributed or self-generation by customers. This focus on conservation, energy efficiency and self-generation may result in a decline in electricity demand, which could adversely affect our business. We could be negatively affected by rising interest rates, downgrades to our credit ratings, adverse credit market conditions or other negative developments in our ability to access capital markets. Our businesses are capital-intensive and, in the ordinary course of business, we are reliant upon adequate long-term and short-term financing to fund our significant capital expenditures, debt service and operating needs. As a result, we are sensitive to developments in interest rates, credit rating considerations, insurance, security or collateral requirements, market liquidity and credit availability and refinancing opportunities necessary or advisable to respond to credit market changes. Changes in these conditions could result in increased costs and decreased availability of credit. In addition, certain sources of debt and equity capital have expressed reservations about investing in companies that rely on fossil fuels. If sources of our capital are reduced, capital costs could increase materially. A downgrade in our credit ratings could negatively affect our ability to access capital and increase the cost of maintaining our credit facilities and any new debt. Credit ratings assigned by Moody's and SP to our businesses and their financial obligations have a significant impact on the cost of capital incurred by our businesses. A ratings downgrade could increase our short-term borrowing costs and negatively affect our ability to fund liquidity needs and access new long-term debt at acceptable interest rates. See "Item 7. Combined Management's Discussion and Analysis of Financial Condition and Results of Operations - Financial Condition - Liquidity and Capital Resources - Ratings Triggers" for additional information on the financial impact of a downgrade in our credit ratings. Our operating revenues could fluctuate on a seasonal basis, especially as a result of extreme weather conditions, including conditions caused or exacerbated by climate change. Our businesses are subject to seasonal demand cycles. For example, in some markets demand for, and market prices of, electricity peak during hot summer months, while in other markets such peaks occur in cold winter months. As a result, our overall operating results may fluctuate substantially on a seasonal basis if weather conditions diverge adversely from seasonal norms. The effects of climate change may accelerate or magnify fluctuations in our operating results. Operating expenses could be affected by weather conditions, including storms, as well as by significant man-made or accidental disturbances, including terrorism or natural disasters. Weather and other factors can significantly affect our profitability or operations by causing outages, damaging infrastructure and requiring significant repair costs. Storm outages and damage often directly decrease revenues and increase expenses, due to reduced usage and restoration costs. Our businesses are subject to physical, market and economic risks relating to potential effects of climate change. Climate change may produce changes in weather or other environmental conditions, including temperature or precipitation levels, and thus may impact consumer demand for electricity. In addition, the potential physical effects of climate change, such as increased frequency and severity of storms, floods, and other climatic events, could disrupt our operations and cause us to incur significant costs to prepare for or respond to these effects. These or other meteorological changes could lead to increased operating costs, capital expenses or power purchase costs. Greenhouse gas regulation could increase the cost of electricity, particularly power generated by fossil fuels, and such increases could have a depressive effect on regional economies. Reduced economic and consumer activity in our service areas -- both generally and specific to certain industries and consumers accustomed to previously lower cost power -- could reduce demand for the power we generate, market and deliver. Also, demand for our energy-related services could be similarly lowered by consumers' preferences or market factors favoring energy efficiency, low-carbon power sources or reduced electricity usage. The Registrants' responses to such climate-related risks include compliance with evolving governmental policy and developing and implementing strategies designed to meet net zero carbon emissions goals, which may affect our financial condition, results of operations or cash flows. We cannot predict the outcome of legal proceedings or investigations related to our businesses in which we are periodically involved. An unfavorable outcome or determination in any of these matters could have a material adverse effect on our financial condition, results of operations or cash flows. We are involved in legal proceedings, claims and litigation and periodically are subject to state and federal investigations arising out of our business operations, the most significant of which are summarized in Item 1. Business and "Regulatory Matters" in Note 7 to the Financial Statements and in "Legal Matters" and "Regulatory Issues" in Note 14 to the Financial Statements. We cannot predict the ultimate outcome of these matters, nor can we reasonably estimate the costs or liabilities that could potentially result from a negative outcome in each case. Significant increases in our operation and maintenance expenses, including health care and pension costs, could adversely affect our future earnings and liquidity. We continually focus on limiting and reducing our operation and maintenance expenses. However, we expect to continue to face increased cost pressures in our operations. Increased costs of materials and labor may result from general inflation, increased regulatory requirements (especially in respect of environmental regulations), the need for higher-cost expertise in the workforce or other factors. In addition, pursuant to collective bargaining agreements, we are contractually committed to provide specified levels of health care and pension benefits to certain current employees and retirees. These benefits give rise to significant expenses. Due to general inflation with respect to such costs, the aging demographics of our workforce and other factors, we have experienced significant health care cost inflation in recent years, and we expect our health care costs, including prescription drug coverage, to continue to increase despite measures that we have taken and expect to take to require employees and retirees to bear a higher portion of the costs of their health care benefits. In addition, we expect to continue to incur significant costs with respect to the defined benefit pension plans for our employees and retirees. The measurement of our expected future health care and pension obligations, costs and liabilities is highly dependent on a variety of assumptions, most of which relate to factors beyond our control. These assumptions include investment returns, interest rates, health care cost trends, inflation rates, benefit improvements, salary increases and the demographics of plan participants. If our assumptions prove to be inaccurate, our future costs and cash contribution requirements to fund these benefits could increase significantly. We may incur liabilities in connection with divestitures. In connection with various divestitures, and certain other transactions, we have indemnified or guaranteed parties against certain liabilities. These indemnities and guarantees relate, among other things, to liabilities which may arise with respect to the period during which we or our subsidiaries operated a divested business, and to certain ongoing contractual relationships and entitlements with respect to which we or our subsidiaries made commitments in connection with a divestiture. See "Guarantees and Other Assurances" in Note 14 to the Financial Statements. We are subject to liability risks relating to our generation, transmission and distribution operations. The conduct of our physical and commercial operations subjects us to many risks, including risks of potential physical injury, property damage or other financial liability, caused to or by employees, customers, contractors, vendors, contractual or financial counterparties and other third parties. Our facilities may not operate as planned, which may increase our expenses and decrease our revenues and have an adverse effect on our financial performance. Operation of power plants, transmission and distribution facilities, information technology systems and other assets and activities subjects us to a variety of risks, including the breakdown or failure of equipment, accidents, security breaches, viruses or outages affecting information technology systems, labor disputes, obsolescence, delivery/transportation problems and disruptions of fuel supply and performance below expected levels. These events may impact our ability to conduct our businesses efficiently and lead to increased costs, expenses or losses. Operation of our delivery systems below our expectations may result in lost revenue and increased expense, including higher maintenance costs, which may not be recoverable from customers. Planned and unplanned outages at our power plants may require us to purchase power at then-current market prices to satisfy our commitments or, in the alternative, pay penalties and damages for failure to satisfy them. Although we maintain insurance coverage for certain of these risks, we do not carry insurance for all of these risks and no assurance can be given that such insurance coverage will be sufficient to compensate us in the event losses occur. We are required to obtain, and to comply with, government permits and approvals. We are required to obtain, and to comply with, numerous permits, approvals, licenses and certificates from governmental agencies. The process of obtaining and renewing necessary permits can be lengthy and complex and sometimes result in the establishment of permit conditions that make the project or activity for which a permit was sought unprofitable or otherwise unattractive. In addition, such permits or approvals may be subject to denial, revocation or modification under circumstances. Failure to obtain or comply with the conditions of permits or approvals, or failure to comply with any applicable laws or regulations, may result in delay or temporary suspension of our operations and electricity sales or the curtailment of our power delivery and may subject us to penalties and other sanctions. Although various regulators routinely renew existing licenses, renewal could be denied or jeopardized by various factors, including failure to provide adequate financial assurance for closure; failure to comply with environmental, health and safety laws and regulations or permit conditions; local community, political or other opposition; and executive, legislative or regulatory action. Our cost or inability to obtain and comply with the permits and approvals required for our operations could have a material adverse effect on our operations and cash flows. In addition, new environmental legislation or regulations, if enacted, or changed interpretations of existing laws may elicit claims that historical routine modification activities at our facilities violated applicable laws and regulations. In addition to the possible imposition of fines in such cases, we may be required to undertake significant capital investments in pollution control technology and obtain additional operating permits or approvals, which could have an adverse impact on our business, results of operations, cash flows and financial condition. War, other armed conflicts or terrorist attacks could have a material adverse effect on our business. War, terrorist attacks and unrest have caused and may continue to cause instability in the world's financial and commercial markets. In addition, unrest could lead to acts of terrorism in the United States or elsewhere, and acts of terrorism could be directed against companies such as ours. Armed conflicts and terrorism and their effects on us or our markets may significantly affect our business and results of operations in the future. In addition, we may incur increased costs for security, including additional physical plant security and security personnel or increased capability following a terrorist incident. We are subject to counterparty performance, credit or other risk in the provision of goods or services to us, which could adversely affect our ability to operate our facilities or conduct business activities. We purchase from a variety of suppliers energy, capacity, fuel, natural gas, transmission service and certain commodities used in the physical operation of our businesses, as well as goods or services, including information technology rights and services, used in the administration of our businesses. Delivery of these goods and services is dependent on the continuing operational performance and financial viability of our contractual counterparties and also the markets, infrastructure or third parties they use to provide such goods and services to us. As a result, we are subject to risks of disruptions, curtailments or increased costs in the operation of our businesses if such goods or services are unavailable or become subject to price spikes or if a counterparty fails to perform. Such disruptions could adversely affect our ability to operate our facilities or deliver services and collect revenues, which could result in lower sales and/or higher costs and thereby adversely affect our results of operations. The performance of coal markets and producers may be the subject of increased counterparty risk to LGE and KU currently due to weaknesses in such markets and suppliers. The coal industry is subject to increasing competitive pressures from natural gas markets, political pressures and new or more stringent environmental regulation, including regulation of combustion byproducts and water inputs or discharges. We are subject to the risk that our workforce and its knowledge base may become depleted in coming years. We experience attrition due primarily to retiring employees, with the risk that critical knowledge will be lost and that it may be difficult to replace departed personnel, and to attract and retain new personnel, with appropriate skills and experience.

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ITEM 1. BUSINESS We were incorporated under the laws of the State of New Jersey in 1985 and our principal executive offices are located at 80 Park Plaza, Newark, New Jersey 07102. We principally conduct our business through two direct wholly owned subsidiaries, PSEG and PSEG Power LLC (PSEG Power), each of which also has its principal executive offices at 80 Park Plaza, Newark, New Jersey 07102. We are an energy company consisting primarily of a regulated electric and gas utility and a nuclear generation business. Over the past few years, our investments resulted in a higher percentage of earnings contribution by PSEG. The sale of the fossil generating portfolio further simplified our business mix, resulting in an even higher percentage of earnings contribution by PSEG going forward and provides more financial flexibility. Our operations are located primarily in the Mid-Atlantic United States. Our business approach focuses on operational excellence, financial strength and disciplined investment. As a holding company, our profitability depends on our subsidiaries operating results. Below are descriptions of our two principal direct operating subsidiaries. PSEG A New Jersey corporation, incorporated in 1924, which is a franchised public utility in New Jersey. It is also the provider of last resort for gas and electric commodity service for end users in its service territory. PSEG earns revenues from its regulated rate tariffs under which it provides electric transmission and electric and natural gas distribution to residential, commercial and industrial (CI) customers in its service territory. It also offers appliance services and repairs to customers throughout its service territory and invests in regulated solar generation projects and regulated energy efficiency (EE) and related programs in New Jersey. PSEG Power A Delaware limited liability company formed in 1999 as a result of the deregulation and restructuring of the electric power industry in New Jersey. PSEG Power earns revenues from its nuclear generation and marketing of power and natural gas to hedge business risks and the value of its portfolio of nuclear power plants, other contractual arrangements and gas storage facilities. In February 2022, we completed the sale of our 6,750 megawatt (MW) fossil generation portfolio which represented an important milestone in our strategy. See Item 8. Note 4. Early Plant Retirements/Asset Dispositions and Impairments for additional information. Our other direct wholly owned subsidiaries are: PSEG Energy Holdings L.L.C. (Energy Holdings), which holds our legacy portfolio of lease investments and interests in offshore wind ventures; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authoritys (LIPA) electric transmission and distribution (TD) system under a contractual agreement; and PSEG Services Corporation (Services), which provides us and our operating subsidiaries with certain management, administrative and general services at cost. OPERATIONS AND STRATEGY PSEG Our regulated TD public utility, PSEG, distributes electric energy and natural gas to customers within a designated service territory running diagonally across New Jersey where approximately 6.5 million people, or about 70% of New Jerseys population resides. Products and Services Our utility operations primarily earn margins through: Transmission the movement of electricity at high voltage from generating plants to substations and transformers, where it is then reduced to a lower voltage for distribution to homes, businesses and industrial customers. Our revenues for these services are based upon tariffs approved by the Federal Energy Regulatory Commission (FERC). Distribution the delivery of electricity and gas to the retail customers home, business or industrial facility. Our revenues for these services are based upon tariffs approved by the New Jersey Board of Public Utilities (BPU). The commodity portion of our utility business electric and gas sales is managed by basic generation service (BGS) and basic gas supply service (BGSS) suppliers. Pricing for those services is set by the BPU as a pass-through, resulting in no margin for our utility operations. In addition, we continue to invest in and pursue opportunities in regulated clean energy, including EE, electric vehicle (EV) make-ready charging infrastructure, solar, energy storage and other potential investments. We also earn margins through competitive services, such as appliance repair, in our service territory. How PSEG Operates We are a transmission owner in PJM Interconnection, L.L.C. (PJM) which is an Independent System Operator (ISO) and Regional Transmission Organization (RTO) that operates the electric transmission system in the Mid-Atlantic Region, including New Jersey and the surrounding states. We provide distribution service to 2.3 million electric customers and 1.9 million gas customers in a service area that covers approximately 2,600 square miles running diagonally across New Jersey. We serve the most densely populated, commercialized and industrialized territory in New Jersey, including its six largest cities and approximately 300 suburban and rural communities. Transmission We use formula rates for our transmission cost of service and investments. Formula rates provide a method of rate recovery where the transmission owner annually determines its revenue requirements through a fixed formula that provides for a recovery of our operating costs and a return of and on our capital investments in the system, net of depreciation expense and deferred taxes (also known as rate base) using an approved return on equity (ROE) in developing the weighted average cost of capital. Under this formula, rates are put into effect in January of each year based upon our internal forecast of annual expenses and capital expenditures. Rates are subsequently trued up to reflect actual annual expenses and capital expenditures. Our current approved rates provide for a base ROE of 9.90% and a 50 basis point adder for our membership in PJM as an RTO. See Item 7. MDAExecutive Overview of 2022 and Future Outlook. We continue to invest in transmission projects as part of PJMs FERC-approved transmission expansion planning process. These projects focus on reliability improvements and replacement of aging infrastructure with planned capital spending of $1.8 billion for transmission in 2023-2025 as disclosed in Item 7. MDACapital Requirements. Distribution PSEG distributes electricity and natural gas to end users in our respective franchised service territories. In October 2018, the BPU issued an Order approving the settlement of our distribution base rate proceeding with new rates effective November 1, 2018. The Order provides for a distribution rate base of $9.5 billion, a 9.60% ROE for our distribution business and a 54% equity component of our capitalization structure. The BPU has also approved a series of PSEG infrastructure, EE, EV and renewable energy investment programs with cost recovery through various clause mechanisms. For a discussion of proposed and approved programs, see Investment Clause Programs below and Item 7. MDAExecutive Overview of 2022 and Future Outlook. Our load requirements are split among residential, CI customers, as described in the following table for 2022: ##TABLE_START % of 2022 Sales Customer Type Electric Gas Commercial 57% 37% Residential 34% 59% Industrial 9% 4% Total 100% 100% ##TABLE_ENDOur customer base has modestly increased since 2018, with electric and gas loads changing as illustrated in the following table: ##TABLE_START Electric and Gas Distribution Statistics Number of Customers as of December 31, 2022 Historical Annual Customer Growth 2018-2022 Electric Sales and Firm Gas Sales as of December 31, 2022 (A) Historical Annual Load Growth 2018-2022 Electric 2.3 Million 0.9 % 40,816 Gigawatt hours % Gas 1.9 Million 0.7 % 2,567 Million Therms 1.4% ##TABLE_END(A) Excludes sales from Gas rate classes that do not impact margin, specifically Contract, Non-Firm Transportation, Cogeneration Interruptible and Interruptible Services. Effective June 1 and October 1, 2021 for electric and gas, respectively, as part of the BPUs approval of the Clean Energy Future-Energy Efficiency (CEF-EE) filing, we implemented the Conservation Incentive Program (CIP) that trues up PSEGs margin to a baseline per customer from our 2018 base rate case for the majority of our customers. As a result, electric gas sales volumes and demands are no longer a driver of our margin and over 90% of our Electric and Gas Distribution margin will only vary based upon the number of customers. Investment Clause Programs The following table lists our major approved investment clause programs that are in progress: ##TABLE_START Program Investment Approval Date Term of Investment Year Started Gas System Modernization Program II (GSMP II) $1.9 billion 2018 5 years 2019 Energy Strong II (ES II) Program $842 million 2019 4 years (A) 2019 CEF-EE $1 billion 2020 3 years (B) 2020 CEF-Energy Cloud (EC) $707 million 2021 4 years 2021 CEF-EV $166 million 2021 ~6 years 2021 Infrastructure Advancement Program (IAP) $511 million 2022 4 years 2022 ##TABLE_END(A) The program has a small amount of trailing costs expected to be spent in year 5. (B) Rolling three-year program with over 80% of spending within 5 years, with limited spending thereafter. GSMP II designed to replace approximately 875 miles of cast iron and unprotected steel mains in addition to other improvements to the gas system. ES II Program structured to harden, modernize and improve the resiliency of our electric and gas distribution systems. To date, we launched three of the four components of our CEF : EE designed to achieve EE targets required under New Jerseys Clean Energy Act through a suite of ten programs for residential, CI programs, including low-income, multi-family, small business and local government. EC driven by the implementation of smart meters, and new software and product solutions to improve our processes and better manage the electric grid. EV primarily relating to preparatory work to deliver infrastructure to the charging point for three programs: residential smart charging; Level-2 mixed use charging; and direct current (dc) fast charging. A remaining component of our program related to medium and heavy duty charging infrastructure is the subject of a stakeholder process that began in 2021 at the BPU. In December 2022, the BPU issued a revised straw proposal on medium and heavy duty vehicle support for public comment. Our CEF-Energy Storage program is being held in abeyance pending future policy guidance from the BPU. Our proposed Energy Storage program is for a $109 million investment that encompasses solar smoothing, whereby a battery energy solar system is used to neutralize fluctuations in solar output to facilitate its entry into the grid, distribution investment deferral, outage management, microgrids and peak reduction for municipal facilities. IAP fashioned to improve the reliability of the last mile of our electric distribution system and address aging substations and gas metering and regulation stations. See Item 7. MDAExecutive Overview of 2022 and Future Outlook for additional information. Solar Generation We have also undertaken solar initiatives at PSEG, which primarily invest in utility-owned solar photovoltaic (PV) grid-connected solar systems installed on PSEG property and third party sites with our economics driven by our net investment in solar, with a contemporaneous return on that rate base. Supply We make no margin on the default supply of electricity and gas since the actual costs are passed through to our customers. All electric and gas customers in New Jersey have the ability to choose their electric energy and/or gas supplier. Pursuant to BPU requirements, we serve as the supplier of last resort for two types of electric and gas customers within our service territory that are not served by another supplier. The first type provides default supply service for smaller CI customers and residential customers at seasonally-adjusted fixed prices for a three-year term (BGS-Residential Small Commercial Pricing (RSCP)). These rates change annually on June 1 and are based on the average price obtained at auctions in the current year and two prior years. The second type provides default supply for larger customers, with energy priced at hourly PJM real-time market prices for a contract term of 12 months (BGS-Commercial Industrial Energy Pricing). We procure the supply to meet our BGS obligations through auctions authorized by the BPU for New Jerseys total BGS requirement. These auctions take place annually in February. Once validated by the BPU, electricity prices for BGS service are set. Approximately one-third of PSEGs total BGS-RSCP eligible load is auctioned each year for a three-year term. For information on current prices, see Item 8. Note 15. Commitments and Contingent Liabilities. PSEG procures the supply requirements of its default service BGSS gas customers through a full-requirements contract with PSEG Power. The BPU has approved a mechanism designed to recover all gas commodity costs related to BGSS for residential customers. BGSS filings are made annually by June 1 of each year, with a targeted effective date of provisional rates by October 1. PSEGs revenues are matched with its costs using deferral accounting, with the goal of achieving a zero cumulative balance by September 30 of each year. In addition, we have the ability to put in place two self-implementing BGSS increases on December 1 and February 1 of up to 5% and also may reduce the BGSS rate at any time and/or provide bill credits. Any difference between rates charged under the BGSS contract and rates charged to our residential customers is deferred and collected or refunded through adjustments in future rates. CI customers that do not select third-party suppliers are also supplied under the BGSS arrangement. These customers are charged a market-based price largely determined by prices for commodity futures contracts. Markets and Market Pricing Historically, there has been significant volatility in commodity prices. A rising commodity price environment results in higher delivered electric and gas rates for customers, which could result in decreased demand for electricity and gas, increased regulatory pressures and greater working capital requirements as the collection of higher commodity costs from our customers may be deferred under our regulated rate structure. A declining commodity price, on the other hand, would be expected to have the opposite effect. PSEG Power Through PSEG Power, we have sought to produce low-cost electricity by efficiently operating our nuclear generation assets while balancing fuel requirements and natural gas supply obligations through energy portfolio management. PSEG Power is a public utility within the meaning of the Federal Power Act (FPA) and the payments it receives and how it operates are subject to FERC regulation. In June 2021, we completed the sale of PSEG Powers solar portfolio. In February 2022, we completed the sale of PSEG Powers 6,750 MW fossil generating portfolio. See Item 8. Note 4. Early Plant Retirements/Asset Dispositions and Impairments for further discussion. Products and Services As a merchant generator, our revenue is derived primarily from energy, capacity and ancillary services to counterparties in the open markets. These products and services may be transacted through exchange markets or bilaterally. PSEG Power also sells wholesale natural gas, primarily through a full-requirements BGSS contract with PSEG to meet the needs of PSEGs customers. In 2022, the BPU approved an extension of the long-term BGSS contract to March 31, 2027, and thereafter the contract remains in effect unless terminated by either party with a two-year notice. Approximately 47% of PSEGs peak daily gas requirements is provided from PSEG Powers firm gas transportation capacity. PSEG Power satisfies the remainder of PSEGs requirements from storage contracts, contract peaking supply, liquefied natural gas and propane. Based upon the availability of natural gas beyond PSEGs daily needs, PSEG Power sells gas to other customers and shares these proceeds with PSEGs customers. PSEG Power also has a 50% ownership interest in a 208 MW generation facility in Hawaii. How PSEG Powers Nuclear Generation Operates As of December 31, 2022, PSEG Power had 3,766 MW of nuclear generation capacity. All of our nuclear generation capacity is located in the Mid-Atlantic region of the United States in one of the countrys largest and most developed electricity markets. Generation Dispatch Our nuclear generation is considered to be base load. Base load units run the most and typically are called to operate whenever they are available. Variable operating costs are low due to the combination of highly efficient operations and the use of relatively lower-cost fuels. Performance is generally measured by the units capacity factor, or the ratio of the actual output to the theoretical maximum output. In PJM, owners of power plants specify prices at which they are prepared to generate and sell energy based on the marginal cost of generating energy from each individual unit. Typically, the bid price of the last unit dispatched by PJM establishes the energy market-clearing price. This method of determining supply and pricing creates a situation where natural gas prices often have a major influence on the price that generators will receive for their output, especially in periods of relatively strong or weak demand. Therefore, changes in the price of natural gas will often translate into changes in the wholesale price of electricity and will continue to have a strong influence on the price of electricity in the markets in which we operate. Market wholesale prices may vary by location resulting from congestion or other factors and do not necessarily reflect our contract prices. Forward prices are volatile and there can be no assurance that current forward prices will remain in effect or that we will be able to contract output at these forward prices. Nuclear Fuel Supply We have long-term contracts for nuclear fuel. These contracts provide for: purchase of uranium (concentrates and uranium hexafluoride), conversion of uranium concentrates to uranium hexafluoride, enrichment of uranium hexafluoride, and fabrication of nuclear fuel assemblies. We expect to be able to meet the fuel supply demands of our customers and our operations. However, the ability to maintain an adequate fuel supply could be affected by several factors not within our control, including changes in prices and demand, curtailments by suppliers, severe weather, environmental regulations, and other factors. For additional information and a discussion of risks, see Item 1A. Risk Factors, Item 7. MDAExecutive Overview of 2022 and Future Outlook and Item 8. Note 15. Commitments and Contingent Liabilities. Markets and Market Pricing All of PSEG

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Powers nuclear generation assets are located within the PJM RTO. Prior to the sale of its fossil generation assets, PSEG Power also had significant sales within the New York ISO (NYISO) and New England ISO (ISO-NE). The price of electricity varies by location in the PJM RTO. Commodity prices, as well as the availability of our fleet of nuclear generation units to operate, have a considerable effect on our profitability. Over the long-term, the higher the forward energy prices are, the more attractive an environment exists for us to contract for the sale of our anticipated output. However, a rising price environment, such as what has been experienced in the past year, also increases the cost of replacement power; thereby placing us at greater risk should our generating units fail to operate effectively or otherwise become unavailable. PSEG Powers Salem 1, Salem 2 and Hope Creek nuclear plants have been awarded Zero Emission Certificates (ZECs) by the BPU through May 2025. These nuclear plants are expected to receive ZEC revenue from the electric distribution companies (EDCs) in New Jersey, which is equivalent to approximately $10 per megawatt hour (MWh) in payments to selected nuclear plants. In addition to energy sales, we earn revenue from capacity payments for our generating assets. These payments are compensation for committing our generating units to PJM for dispatch at its discretion. Capacity payments reflect the value to PJM of assurance that there will be sufficient generating capacity available at all times to meet system reliability and energy requirements. See Item 7. MDAExecutive Overview of 2022 and Future OutlookWholesale Power Market Design. In PJM the market design for capacity payments provides for a structured, forward-looking, capacity pricing mechanism through the Reliability Pricing Model (RPM). For additional information regarding FERC actions related to the capacity market construct, see Regulatory IssuesFederal Regulation. The prices to be received by generating units in PJM for capacity have been set through RPM base residual and incremental auctions and depend upon the zone in which the generating unit is located. The average capacity prices that PSEG expects to receive from the base residual and incremental auctions which have been completed are disclosed in Item 8. Note 3. Revenues. We have obtained price certainty for our PJM capacity through May 2024 through the RPM pricing mechanism. However, there is currently regulatory and timing uncertainty regarding the June 2024 through May 2025 planning year as discussed in Regulatory IssuesFederal Regulation. In addition, the PJM capacity market imposes rigorous performance obligations and non-performance penalties on resources during times of system stress. These rules provide an opportunity for bonus payments or require the payment of penalties depending on whether a unit is available during a performance interval. Hedging Strategy To mitigate volatility in our results, we seek to contract in advance for a significant portion of our anticipated electric output, capacity and fuel needs. We seek to sell a portion of our anticipated lower-cost generation over a multi-year forward horizon, normally over a period of two to three years. We believe this hedging strategy increases the stability of earnings. Generally, we seek to hedge our output through sales at PJM West or other nodes corresponding to our generation portfolio. Sales in PJM generally reflect block energy sales at the liquid PJM Western

Hub or other basis locations when available and other transactions that seek to secure price certainty for our energy output. Although we enter into these hedges to provide price certainty for a large portion of our anticipated generation, there is variability in both our actual output as well as in the effectiveness of our hedges. Our hedging practices help to manage some of the volatility of the merchant power business. While this limits our exposure to decreasing prices, our ability to realize benefits from rising market prices, as experienced in the past two years, is also limited. Therefore, our realized prices in 2022 were significantly lower than market pricing due to forward sales contracts executed in prior years for delivery in 2022. For this same reason, expected realized prices in forward periods will also be limited to when hedges were transacted and not based upon forward market prices. In August 2022, the Inflation Reduction Act (IRA) was signed into law expanding incentives promoting carbon-free generation. The enacted legislation established the production tax credit (PTC) for electricity generation using nuclear energy set to begin in 2024 through 2032. PSEG Powers Salem 1, Salem 2, Hope Creek, Peach Bottom 2 and Peach Bottom 3 nuclear plants will each benefit from the PTC. The expected PTC rate is up to $15/MWh subject to adjustment based upon a facilitys gross receipts. The PTC rate and the gross receipts cap are subject to annual inflation adjustments. The U.S. Treasury is expected to clarify the definition of gross receipts prior to when the eligibility period begins in 2024. We are continuing to analyze the impact of the IRA on our nuclear units, including additional future guidance from the U.S. Treasury, potential impacts on hedging strategies and the impact of PTCs on expected ZEC payments. Our fuel strategy is to maintain certain levels of uranium in inventory and to make periodic purchases to support such levels. Our nuclear fuel commitments cover approximately 100% of our estimated uranium, enrichment and fabrication requirements through 2024 and a significant portion through 2025. More than 90% of PSEG Powers expected gross margin in 2023 from the nuclear generation assets relates to our energy hedging strategy, our expected revenues from the capacity market mechanisms described above, ZEC revenues and certain gas operations and ancillary service payments such as reactive power. The contracted percentages of our anticipated base load generation output for the next two years are as follows: ##TABLE_START Nuclear Generation 2023 2024 Generation Sales 95%-100% 55%-60% ##TABLE_ENDEnergy Holdings Energy Holdings maintains our legacy portfolio of domestic lease investments and offshore wind interests. See Item 8. Note 9. Long-Term Investments and Note 10. Financing Receivables for additional information. Offshore Wind PSEG holds a 25% equity interest in rsted North America Inc.s (rsted) Ocean Wind 1 project which is currently in development. In January 2023, PSEG agreed to sell to rsted its 25% equity interest in Ocean Wind 1. The sale is not contingent upon rsted electing to proceed to the construction phase of the project. The sale is contingent upon finalization of a purchase and sale agreement with rsted and other closing conditions as well as any potential state regulatory approval that may be required to close on the transaction. Additionally, PSEG and rsted each owns 50% of Garden State Offshore Energy LLC (GSOE) which holds rights to an offshore wind lease area just south of New Jersey. PSEG has decided not to exercise its option to purchase 50% of rsteds Skipjack projects in Maryland (one of which would utilize a portion of the GSOE lease area) or pursue an ownership interest in rsteds Ocean Wind 2 offshore wind project or other offshore wind generation projects. PSEG is evaluating its options for the potential sale of its interest in GSOE . See Item 8. Note 5. Variable Interest Entities for additional information. LIPA Operations Services Agreement In accordance with a twelve year Operations Services Agreement (OSA) entered into by PSEG LI and LIPA, PSEG LI commenced operating LIPAs electric TD system in Long Island, New York on January 1, 2014. Following the effects of Tropical Storm Isaias, LIPA and PSEG LI agreed to an amended OSA which became effective in 2022. The OSA contract term continues through 2025, but can be extended for five years subject to a mutual agreement of the parties. Under the OSA, PSEG LI acts as LIPAs agent in performing many of its obligations and in return (a) receives reimbursement for pass-through operating expenditures, (b) receives a fixed management fee and (c) is eligible to receive an incentive fee contingent on meeting established performance metrics. Further, since January 2015, PSEG Power provides fuel procurement and power management services to LIPA under separate agreements. It is uncertain whether the OSA and the separate agreements will be renewed on terms acceptable to us or at all. COMPETITIVE ENVIRONMENT PSEG Our TD business is not affected when customers choose alternate electric or gas suppliers since we earn our return on our net investment in rate base to provide TD service, not by supplying the commodity. Based on our transmission formula rate and the CIP program for electric and gas distribution, we are also minimally impacted by changes in customers usage. Our growth is driven by (i) our investment program to deliver energy more reliably by modernizing our electric transmission and electric and gas distribution system and (ii) investing in programs that help deliver cleaner energy, including our EE programs to help customers use less energy and investment programs to build EV infrastructure and solar generation. There may also be opportunities to expand into related clean energy areas, such as renewable natural gas, hydrogen, energy storage, additional solar and renewables, and broader EE investments, though utility participation in these areas is subject to regulatory approval and market design, which continues to evolve. That growth can be affected by customer cost pressures which could result from higher commodity costs, higher supply costs to support subsidized renewable generation, higher operating costs, higher tax rates, macro-economic conditions including inflation, and other factors. While there is not a substantial amount of net metered generation in our territory, a growing amount, and/or other changes in customer usage behavior could lead to a smaller base of customer usage to recover our costs, resulting in higher rates overall. Conversely, an increase in EV adoption and other factors could lead to an increase in system usage, require incremental investments to meet higher peak demands and result in a larger customer usage base. There is also an expected shift toward greater electrification and less gas usage in the coming decades, with several jurisdictions setting targets to move new construction to be exclusively electric. While current costs and relative emission savings would limit any substantial change in the near term, technological advances for heat pumps, actions by certain jurisdictions in our service territory and other factors could accelerate these potential changes, resulting in a slowing in the growth of our gas distribution and an increase in the growth of our electric TD business. Our CIP reduces the impact on our distribution revenues from changes in sales volumes and demand for most customers. The CIP, which is calculated annually, provides for a true-up of our current period revenue as compared to revenue thresholds established in our most recent distribution base rate proceeding. Recovery under the CIP is subject to certain limitations, including an actual versus allowed ROE test and ceilings on customer rate increases. Changes previously ordered by FERC and implemented by PJM and other ISOs to eliminate contractual provisions that previously provided us a right of first refusal to construct new transmission projects in our service territory, could result in third-party construction of transmission lines in our area in the future and also allow us to seek opportunities to build in other service territories. While there has been minimal impact so far, these rules continue to evolve so both the extent of the risk within our service territory and the opportunities for our transmission business elsewhere remain difficult to assess. PSEG Power Various market participants compete with us and one another in transacting in the wholesale energy markets and entering into bilateral contracts. Our competitors include (i) merchant generators, (ii) domestic and multi-national utility generators, (iii) energy marketers and retailers, (iv) private equity firms, banks and other financial entities, (v) fuel supply companies, and (vi) affiliates of other industrial companies, and companies that promote and aggregate demand side management (DSM) and other EE efforts that could reduce load. New additions of lower-cost or more efficient generation capacity, as well as subsidized generation capacity, or technological advances such as distributed generation and microgrids could make our plants less economic in the future. Such capacity could impact market prices and our competitiveness. Adverse changes in energy industry law, policies and regulation could have significant economic, environmental and reliability consequences. For example, PJM has a capacity market that has been approved by FERC. FERC regulates this market and continues to examine whether this market design is working optimally. PJM itself often changes capacity market rules, which can cause uncertainty for market participants. Various forums are considering how the competitive market framework can incorporate or be reconciled with state public policies that support particular resources, resource attributes or emerging technologies, whether generators are being sufficiently compensated in the capacity market and whether subsidized resources may be adversely affecting capacity market prices. For information regarding recent actions by FERC relating to capacity market design, see the discussion in Regulatory IssuesFederal Regulation. Environmental issues could also impact our competitiveness, including requirements regarding capital investments at our nuclear stations, such as cooling towers, could lead to a material adverse effect, while other actions to further regulate carbon dioxide emissions could better position our nuclear plants . While it is our expectation that continued efforts may be undertaken by the federal and state governments to preserve the existing base nuclear generating plants, we still believe that pressures from renewable resources will continue to increase. HUMAN CAPITAL MANAGEMENT Our human capital management strategy is integrated with our overall environmental, social, and governance (ESG) goals and is designed to support our ability to attract, develop, and retain a high performing diverse workforce and to continue building on our culture of inclusion to sustain our business, both today and in the future. We strive for a fair, equitable and transparent approach to human capital management. The Organization and Compensation Committee of the PSEG Board of Directors is responsible for oversight of PSEGs human capital management practices and is updated regularly on matters related to diversity, equity and inclusion (DEI), workforce development and succession planning. The following charts present our total employee population indicating percentages of employees that are represented by a collective bargaining unit, are women, or are racially and/or ethnically diverse: In 2022, of our external hires, including temporary employees, 23% were women and 40% were racially and/or ethnically diverse. PSEGs voluntary attrition rate for the year was 6.5% (3.3% retirements and 3.2% resignations). The average employee tenure is 14 years. Health, Safety and Well-Being We emphasize the priority of protecting the health, safety and well-being of our employees, contractors and the communities that we serve. We demonstrate this by providing support to employees so that everyone is empowered and encouraged to question, stop and correct any unsafe act or condition. In the event that there is a safety issue, our employees take responsibility for the accurate, honest, and timely reporting of all incidents and injuries. To hold ourselves accountable, we have annual performance goals related to compliance with health and safety policies, practices and procedures. Culture, Diversity, Equity and Inclusion We aspire for a culture of belonging and equity, where diversity is celebrated and inclusion is the norm. Since publishing our first DEI report in 2021, we have continued to build on our Inclusion for All strategy. Our DEI program combines individual and site-specific efforts with leadership development and training activities. Our 12 Employee Business Resource Groups support key business goals and priorities; help build meaningful connections through community outreach and volunteerism, mentorship and professional development; elevate diverse perspectives; and create spaces for employees to learn from each other. To measure the effectiveness of our DEI and workplace culture efforts, we solicit feedback from employees through focus groups, listening sessions and employee experience surveys. In 2022, we saw improvements in many areas, including comfort speaking up, belonging, and manager relationship, with an overall engagement score of 82%. Our initiatives to advance DEI includes doing business with certified minority, women, veteran LGBT-owned businesses and maintaining a supplier diversity process that is integrated into our company culture. PSEG achieved its goal to spend 30% with diverse suppliers by 2023 in 2021, two years ahead of schedule. Talent, Attraction and Development Our talent acquisition strategy is focused on hiring the workforce necessary to serve our customers and meet our business objectives. As part of these efforts, we work to attract employees who reflect broad dimensions of diversity, including race, gender, disability, generation, education, and other traits and characteristics that make each person who they are. Our employees grow through a variety of training and development opportunities offered to individual contributors, front line supervisors, managers and leaders. We invest in technical and operational training for our craft and field workers to support safe and reliable operations. We utilize data-driven workforce planning and succession processes to prepare for the future of work. Total Rewards In addition to our competitive pay, incentives, and health, welfare and retirement programs, our Total Rewards offerings consider the safety and overall well-being of our employees. We offer an array of programs designed to support physical, emotional, and financial wellness. Labor Relations We are proud of the partnership we have with union leadership across our six unions and the employees they represent in our workforce. We believe our strong relationship with our unions allowed for negotiation of permanent agreements that support PSEGs flexible work model and other mid-term agreements that support strategic objectives and business goals. REGULATORY ISSUES In the ordinary course of our business, we are subject to regulation by, and are party to various claims and regulatory proceedings with FERC, the BPU, the Commodity Futures Trading Commission (CFTC) and various state and federal environmental regulators, among others. For information regarding material matters, other than those discussed below, see Item 8. Note 15. Commitments and Contingent Liabilities. In addition, information regarding PSEGs specific filings pending before the BPU is discussed in Item 8. Note 7. Regulatory Assets and Liabilities. Federal Regulation FERC is an independent federal agency that regulates the transmission of electric energy and natural gas in interstate commerce and the sale of electric energy and natural gas at wholesale pursuant to the FPA and the Natural Gas Act. PSEG and certain operating subsidiaries of PSEG Power are public utilities as defined by the FPA. FERC has extensive oversight over such public utilities. FERC approval is usually required when a public utility seeks to: sell or acquire an asset that is regulated by FERC (such as a transmission line or a generating station); collect costs from customers associated with a new transmission facility; charge a rate for wholesale sales under a contract or tariff; or engage in certain mergers and internal corporate reorganizations. FERC also regulates RTOs/ISOs, such as PJM, and their regional transmission planning processes as well as their energy and capacity markets. Transmission Regulation FERC has exclusive jurisdiction to establish the rates and terms and conditions of service for interstate transmission. We currently have FERC-approved formula rates in effect to recover the costs of our transmission facilities. Under this formula, rates are put into effect in January of each year based upon our internal forecast of annual expenses and capital expenditures. Rates are subsequently trued up to reflect actual annual expenses and capital expenditures. Transmission Rate Proceedings and ROE From time to time, various matters are pending before FERC relating to, among other things, transmission planning, reliability standards and transmission rates and returns, including incentives. Depending on their outcome, any of these matters could materially impact our results of operations and financial condition. In a rulemaking proceeding issued in 2021, FERC has proposed to eliminate the existing 50 basis point adder for RTO membership, which is currently available to PSEG and other transmission owners in RTOs. Elimination of the RTO adder for RTO membership would reduce PSEGs annual Net Income and annual cash inflows by approximately $30 million-$40 million. Transmission Planning Proceedings During 2022, FERC issued several rulemakings and notices that examine current transmission planning proceedings to determine whether the rules as currently implemented will facilitate the integration of renewable resources onto the grid and whether there is sufficient oversight over transmission costs to protect customers. Among other issues, FERC is considering whether transmission competitive solicitations are working as intended, whether interconnection queue rules for new generation should dramatically change and whether some type of transmission monitor construct to oversee costs should be imposed. FERCs consideration of many of these issues is still in its early stages. Regulation of Wholesale SalesGeneration/Market Issues/Market Power Under FERC regulations, public utilities that wish to sell power at market rates must receive FERC authorization (market-based rate (MBR) authority) to sell power in interstate commerce before making power sales. They can sell power at cost-based rates or apply to FERC for authority to make MBR sales. For a requesting company to receive MBR authority, FERC must first determine that the requesting company lacks market power in the relevant markets and/or that market power in the relevant markets is sufficiently mitigated. Certain PSEG companies are public utilities and currently have MBR authority. These companies, which include PSEG Energy Resources Trading LLC, PSEG Nuclear LLC and PSEG must file at FERC every three years to update their market power analyses. At the end of 2022, PSEG filed such a market power update at FERC, which remains pending. Energy Clearing Prices Energy clearing prices in the markets in which we operate are generally based on bids submitted by generating units. Under FERC-approved market rules, bids are subject to price caps and mitigation rules applicable to certain generation units. FERC rules also govern the overall design of these markets. At present, all units, including those owned by PSEG, within a delivery zone receive a clearing price based on the bid of the marginal unit (i.e. the last unit that must be dispatched to serve the needs of load) which can vary by location. Capacity Market Issues PJM operates a capacity market that has been approved by FERC. FERC regulates the capacity market and continues to examine whether the market design is working optimally. Various forums are considering how the competitive market framework can incorporate or be reconciled with state public policies that support particular resources, resource and environmental attributes or emerging technologies, whether generators are being sufficiently compensated in the capacity market and whether subsidized resources may be adversely affecting capacity market prices. We cannot predict what action, if any, FERC might take with regard to capacity market design. The RPM is the locational installed capacity market design for the PJM region, including a forward auction for installed capacity. Under the RPM, generators located in constrained areas within PJM are paid more for their capacity as an incentive to ensure adequate supply where generation capacity is most needed. The mechanics of the RPM in PJM continue to evolve and be refined in stakeholder proceedings and FERC proceedings in which we are active. In July 2021, PJM submitted to FERC a proposal to scale back the PJM Minimum Offer Price Rule (MOPR) to accommodate state public policy programs that do not attempt to set the price of capacity. Under the PJM proposal, PSEG Powers New Jersey nuclear plants that receive ZEC payments are not subject to the MOPR. In September 2021, FERC issued a notice that it was not able to act on PJMs proposed changes to the MOPR because of a split among the Commissioners on the lawfulness of PJMs proposal. Therefore, PJMs rules became automatically effective as of September 29, 2021 and they were applied to the June 2022 base residual auction. In November 2021, a group of generators challenged these MOPR rules in the Court of Appeals for the Third Circuit on the grounds that FERCs inaction was unlawful. PSEG intervened in the proceeding in support of the MOPR rules. Oral argument on the appeal was held in January 2023. We cannot predict the outcome of this proceeding. In another order related to the auction, FERC found that the current rules related to the Market Seller Offer Cap were unjust and unreasonable and ultimately eliminated the default offer cap. In its place, FERC adopted a unit-specific approach to reviewing certain capacity market offers. These new rules resulted in lower capacity prices for other market participants, including PSEG, and therefore, lower revenues for PSEG in the June 2022 base residual auction since market offers for many resource types need to be approved by the Independent Market Monitor and PJM. PJMs most recent base residual auction was held at the beginning of December 2022. However, in mid-December, PJM communicated to all market participants that it is not announcing the results of this auction while it waits for FERC to act on emergent filings it has made at FERC proposing to change how the reliability requirement for a specific capacity market deliverability area will be calculated effective December 24, 2022. PJMs filings at FERC, and its related decision to postpone the announcement of base residual auction results, creates uncertainty for market participants, including PSEG. We cannot predict the outcome of these developments at this time. Compliance Reliability Standards Congress has required FERC to put in place, through the North American Electric Reliability Corporation (NERC), national and regional reliability standards to ensure the security and reliability of the U.S. electric transmission and generation system (grid) and to prevent major system blackouts. As a result, under NERCs physical security standard, approved by FERC in 2015, utilities are required to identify critical substations as well as develop threat assessment plans to be reviewed by independent third parties. In our case, the third-party is PJM. As part of these plans, utilities can decide or be required to build additional redundancy into their systems. Additionally, under NERCs supply chain standard approved by FERC in 2018, PSEG has developed security controls for supply chain management associated with the procurement of industrial control system hardware, software, and services related to grid operations. These standards implement the Critical Infrastructure Protection standards that are already in place and that establish physical and cybersecurity protections for critical systems. We have documented procedures and implemented new processes to comply with these standards. The NERC continues to examine revising criteria for low-impact cyber systems, which could result in expanding the Critical Infrastructure Protection standards to a larger set of applicable cyber assets. CFTC In accordance with the Dodd-Frank Wall Street Reform and Consumer Protection Act, the SEC and the CFTC continue to implement a regulatory framework for swaps and security-based swaps. The rules are intended to reduce systemic risk, increase transparency and promote market integrity within the financial system by providing for the registration and comprehensive regulation of swap dealers and by imposing recordkeeping, data reporting, margin and clearing requirements with respect to swaps. We are currently subject to recordkeeping and data reporting requirements applicable to commercial end users. The CFTC finalized new rules establishing federal position limits for trading in certain commodities, such as natural gas. Entities such as PSEG began complying with the rules on January 1, 2022. Nuclear Nuclear Regulatory Commission (NRC) Our operation of nuclear generating facilities is subject to comprehensive regulation by the NRC, a federal agency established to regulate nuclear activities to ensure the protection of public health and safety, as well as the environment. Such regulation involves testing, evaluation and modification of all aspects of plant operation in light of NRC safety, security, cybersecurity, and environmental requirements. Continuous demonstration to the NRC that plant operations meet requirements is necessary. The NRC has the ultimate authority to determine whether any U.S. nuclear generating unit may operate. The NRC conducts ongoing reviews of nuclear industry operations experience and may issue or revise regulatory requirements. We are unable to predict the final outcome of these reviews or the cost of any actions we would need to take to comply with any new regulations, including possible modifications to the Salem, Hope Creek and Peach Bottom facilities, but such costs could be material. The current operating licenses of our nuclear facilities expire in the years shown in the following table: ##TABLE_START Unit Year Salem Unit 1 2036 Salem Unit 2 2040 Hope Creek 2046 Peach Bottom Unit 2 (A) 2033 Peach Bottom Unit 3 (A) 2034 ##TABLE_END(A) Depreciation Expense and the Asset Retirement Obligation assume these units will operate through 2053 and 2054, respectively, given our expectation that previously approved operating license expiration dates will be restored by the NRC. See Item 8. Note 13. Asset Retirement Obligations (AROs) for additional information. State Regulation Our principal state regulator is the BPU, which oversees electric and natural gas distribution companies in New Jersey. We are also subject to various other states regulations due to our operations in those states. Our New Jersey utility operations are subject to comprehensive regulation by the BPU including, among other matters, regulation of retail electric and gas distribution rates and service, the issuance and sale of certain types of securities and compliance matters. In addition to base rates, we recover certain costs or earn on certain investments pursuant to mechanisms known as adjustment clauses. These clauses permit the flow-through of costs to, or the recovery of investments from, customers related to specific programs, outside the context of base rate proceedings. Recovery of these costs or investments is subject to BPU approval for which we make periodic filings. Delays in the pass-through of costs or recovery of investments under these mechanisms could result in significant changes in PSEGs cash flow. PSEGs participation in solar, EV and EE programs is also regulated by the BPU, as the terms and conditions of these programs are approved by the BPU. BPU regulation can also have a direct or indirect impact on our power generation business as it relates to energy supply agreements and energy policy in New Jersey. New Jersey Energy Master Plan (EMP) In January 2020, the State of New Jersey released its EMP. While the EMP does not have the force of law and does not impose any obligations on utilities, it outlines current expectations regarding the States role in the use, management, and development of energy. The EMP recognizes the goals of New Jerseys Clean Energy Act of 2018 (the Clean Energy Act) to achieve, by 2026, annual reductions of electric and gas consumption of at least 2% and 0.75%, respectively, of the average of the prior three years of retail sales. The annual reductions were subsequently adjusted to 2.15% for electric and 1.10% for gas by 2027 in the BPUs EE framework approved in June 2020. The EMP outlines several strategies, including statewide EE programs; expansion of renewable generation (solar and offshore wind), energy storage and other carbon-free technologies; preservation of existing nuclear generation; electrification of the transportation sector; and reduced reliance on natural gas. We cannot predict the impact on our business or results of operations from the EMP or any laws, rules or regulations promulgated as a result thereof, particularly as they may relate to PSEG Powers nuclear generating stations and PSEGs electric transmission and gas distribution assets. In January 2023, the New Jersey governors office announced the commencement of planning for the development of a new EMP for release in 2024. The 2024 EMP will update and expand upon the existing EMP and consider recent state and federal policies and how federal funding can provide additional support for advancement of critical clean energy policies. Gas Capacity Review In September 2019, the BPU formally opened a stakeholder proceeding to explore gas capacity procurement service to all New Jersey natural gas customers. The BPU retained a consultant and in June 2022 accepted the consultants key finding that, through 2030, New Jerseys firm gas capacity can meet firm demand under normal design day conditions. The only potential gas supply shortfall was found during extreme weather (i.e. a winter day that could be expected to occur only once in 90 years) and/or a perfect storm, which occurs when there is an outage on a transcontinental pipeline during a design day. The BPU noted that its consultants analysis supports the argument against the need for additional interstate pipeline capacity and also supports the BPUs aggressive policy approach to reduce the States overall reliance on fossil fuels, and achieve the Governors goal of 100% clean energy by 2050. BGS Process In July 2022, the States EDCs, including PSEG, filed their annual proposal for the conduct of the February 2023 BGS auction covering energy years 2024 through 2026. In November 2022, the BPU issued its decision to approve the joint EDCs proposals regarding the

BGS auction process. In addition to addressing procedural issues for conducting the annual BGS auction, the BPUs November 2022 order addressed EV charging supply rate issues and required that the EDCs must (i) continue to collect EV charging data and coordinate with BPU Staff in developing a BGS rate solution for commercial dc fast charging EV stations, and must include chargers and submit a proposal regarding the rate design in the June 1, 2023 joint EDC BGS filing; and (ii) implement by June 1, 2023 a BGS rate solution for residential EV charging customers similar to distribution rate off-peak charging solutions put in place in some of the EDCs (including PSEGs) light duty EV incentive programs. EV Activity Consistent with the policy set forth in New Jerseys EMP, the BPU has supported electrification of the transportation sector. EDCs in New Jersey, including PSEG, are making investments, approved by the BPU for recovery in rates, initially focused on light duty vehicles, such as preparatory work to deliver infrastructure to the EV charging point. In June 2021, the BPU issued an initial straw proposal for the establishment of an EV infrastructure ecosystem for medium and heavy duty EVs in New Jersey, and conducted a series of stakeholder meetings to discuss that ecosystem. In December 2022, the BPU issued a revised straw proposal for public comment. Although we cannot predict the outcome of the stakeholder process, we anticipate that this effort will result in opportunities for EDCs to target infrastructure investments for the medium and heavy duty EV market. Grid Modernization In October 2021, the BPU commenced a stakeholder proceeding to develop and implement a systemic Grid Modernization plan in accordance with strategies outlined in the New Jersey EMP. The BPU retained a consultant that gathered detailed and comprehensive information from the States EDCs, including PSEG, regarding resource issues and policy changes needed to interconnect the clean energy capacity required under state policy. In June 2022, the BPUs consultant issued a draft report with its findings and recommendations to update the BPUs interconnection regulations and processes. We cannot predict the impact on our business or results of operations from this Grid Modernization plan or any laws, rules or regulations promulgated as a result thereof, particularly as they may relate to PSEGs electric distribution assets. New Jersey Solar Initiatives Pursuant to the Clean Energy Act, the BPU was required to undertake several initiatives in connection with New Jerseys solar energy market. In 2019, the BPU established a Community Solar Energy Pilot Program, permitting customers to participate in solar energy projects remotely located from their properties, and allowing for bill credits related to that participation. Still pending with the BPU are certain issues, including minor modifications to the community solar pilot program, discussions regarding the potential implementation of consolidated billing for the benefit of project developers and participants, and development of a cost recovery mechanism for the EDCs. The Clean Energy Act required the BPU to close the then-existing Solar Renewable Energy Certificate (SREC) program to new applications at the earlier of June 1, 2021 or the date at which 5.1% of New Jersey retail electric sales were derived from solar. The 5.1% threshold was attained and the SREC market was closed to new applications on April 30, 2020, with limited exceptions related to the impact of COVID-19 on projects under development. Solar projects that failed to achieve commercial operation before April 30, 2020 may be entitled to receive transition renewable energy certificates (TRECs) for each MWh of solar production. The New Jersey EDCs, including PSEG, are required to purchase, using the services of a TREC administrator, TRECs from solar projects at rates set by the BPU. In July 2021, the BPU issued an order formally establishing the Successor Solar Incentive (SuSI) Program, heavily drawing upon the predecessor TREC program, to serve as the permanent program for providing solar incentives to qualified solar electric generation facilities. The program provides for incentive payments at prices established in the BPUs July 2021 order in the form of SREC-IIs for each MWh generated by net-metered projects of 5 MW or less, and an annual competitive solicitation, the Competitive Solar Incentive (CSI) program, to establish SREC-II prices applicable to grid-supply projects and net-metered projects in excess of 5 MW. The States EDCs have retained an administrator to acquire all of the SREC-IIs received each year by eligible solar generation projects. Each EDC, in turn, may recover from its customers the reasonable and prudent costs for SREC-II procurement and SREC-II administrator fees, based on its proportionate share of retail electric sales, and other costs reasonably and prudently incurred in the disposition of its SuSI obligations. Pursuant to an order issued by the BPU in December 2022, bids for the CSI program opened on February 1, 2023 and close on March 31, 2023. Cybersecurity In an effort to reduce the likelihood and severity of cybersecurity incidents, we have established a comprehensive cybersecurity program designed to protect and preserve the confidentiality, integrity and availability of our technology systems. The Board of Directors, its Industrial Operations Committee (IOC) and Audit Committee, and senior management receive frequent reports on such topics as personnel and resources to monitor and address cybersecurity threats, technological advances in cybersecurity protection, rapidly evolving cybersecurity threats that may affect us and our industry, cybersecurity incident response and applicable cybersecurity laws, regulations and standards, as well as collaboration mechanisms with intelligence and enforcement agencies and industry groups, to assure timely threat awareness and response coordination. Our cybersecurity program is focused on the following areas: Governance Board OversightThe Boards IOC holds the primary responsibility, as enumerated in its charter, of overseeing PSEGs cybersecurity program. Cybersecurity is a standing agenda item at each IOC meeting, which includes discussion on operational technology cyber risk, a cybersecurity update from the Chief Information Security Officer (CISO), and review of a corporate cybersecurity scorecard. In addition, the IOC meets with the CISO in executive session at each meeting with no other members of management present. Cybersecurity Councilwhich is comprised of members of senior management, meets regularly to discuss emerging cybersecurity issues and maintenance of the cybersecurity scorecard to measure performance of key risk indicators. The Cybersecurity Council ensures that senior management, and ultimately, the Board, is given the information required to exercise proper oversight over cybersecurity risks and that escalation procedures are followed. The Senior Vice

President, Chief Information and Digital Officer has the overall responsibility for cybersecurity. Documented corporate practice to ensure delineated cybersecurity incidents, or potential incidents, are escalated promptly to senior management. Training and AwarenessProviding annual cybersecurity training for all personnel with network access, as well as additional education for personnel with access to industrial control systems or customer information systems; and conducting phishing exercises with progressive consequences for failures. Employees also receive periodic cybersecurity awareness messages and each October are invited to presentations throughout the month from internal and external cyber experts covering diverse cyber topics. Technical SafeguardsManaging controls to protect our network perimeter, internal Information Technology (IT) and Operational Technology (OT) environments, such as internal and external firewalls, network intrusion detection and prevention, penetration testing, vulnerability assessments, threat intelligence, anti-malware and access controls. Vendor ManagementMaintaining a risk-based vendor management program, including the development of robust security contractual provisions. Incident Response PlansMaintaining and updating a cyber incident response plan that addresses the life cycle of a cybersecurity incident from a technical perspective (i.e., detection, response, and recovery), as well as data breach response (with a focus on external communication and legal compliance); and conducting regular table top exercises to test plan effectiveness (both internally and through external exercises). Mobile SecurityMaintaining controls to prevent loss of data through mobile device channels. PSEG also maintains physical security measures to protect its OT systems, consistent with a defense in depth and risk-tiered approach. Such physical security measures may include access control systems, video surveillance, around-the-clock command center monitoring, and physical barriers (such as fencing, walls, and bollards). Additional features of PSEGs physical security program include threat intelligence, insider threat mitigation, background checks, a threat level advisory system, a business interruption management model, and active coordination with federal, state, and local law enforcement officials. See Regulatory IssuesFederal Regulation for a discussion of Critical Infrastructure Protection standards that the NERC has promulgated that mitigate risk associated with both cybersecurity and physical security of PSEGs critical facilities. In addition, we are subject to federal and state requirements designed to further protect against cybersecurity threats to critical infrastructure, as discussed below. For a discussion of the risks associated with cybersecurity threats, see Item 1A. Risk Factors. Federal NERC, at the direction of FERC, has implemented national and regional reliability standards to ensure the reliability and security of the grid and to prevent major system blackouts. NERC Critical Infrastructure Protection standards establish cybersecurity and physical security protections for critical systems and facilities. These standards are also designed to develop coordination, threat sharing and interaction between utilities and various government agencies regarding potential cyber and physical threats against the nations electric grid. The Transportation Security Administration (TSA), an agency of the U.S. Department of Homeland Security (DHS), has issued three security directives since May 2021 designed to mitigate cybersecurity threats to natural gas pipelines. The first security directive requires pipeline owners/operators to (i) report actual and potential cybersecurity incidents to the Cybersecurity and Infrastructure Security Agency, a DHS agency; (ii) designate a Cybersecurity Coordinator; (iii) review their current cybersecurity practices; and (iv) identify any gaps and related remediation measures to address cyber-related risks. The second security directive requires pipeline owners/operators to (i) implement specific mitigation measures to protect against cyber threats; (ii) implement a cybersecurity contingency and recovery plan; and (iii) conduct a cybersecurity architecture design review. The third security directive requires pipeline owners/operators to (i) establish and implement a TSA-approved Cybersecurity Implementation Plan; (ii) develop and maintain a Cybersecurity Incident Response Plan to reduce the risk of operational disruption; and (iii) establish a Cybersecurity Assessment Program, and submit an annual plan to the TSA that describes how the entity is assessing the effectiveness of its cybersecurity measures. The NERC Critical Infrastructure Protection standards do not apply to nuclear facilities which are instead governed by the NRC for purposes of physical and cyber security. NRC has a number of risk-informed, performance-based security programs in place to effectively protect U.S. commercial nuclear facilities. The NRC has existing requirements, effective processes, and the expertise to regulate and inspect cybersecurity to ensure the federal requirements are met. NRC requires operating nuclear power plant licensee and license applicants to ensure that digital computer and communication systems associated with a nuclear power plants safety, security, and emergency preparedness functions are protected from cyberattacks. As a result, computer systems at operating power plants that monitor and control safety systems and help the reactor operate are isolated from external communications. Security systems that provide safeguards of the facility are also isolated from external communications, including the Internet. NRCs Office of Nuclear Security and Incident Response established the Cyber Security Branch (CSB) to strengthen internal governance of the agencys regulatory activities. The CSB plans, coordinates, and manages agency activities related to cybersecurity for NRC applicants and licensees, such as security programs development and policy enhancements to prevent malevolent cyber acts against NRC-licensed facilities. The CSBs cybersecurity-related responsibilities include developing rules and guidance, reviewing licensing actions, developing policy enhancements, and overseeing NRC-licensed facilities. NRC regularly monitors the threats associated with cybersecurity, including potential threats against NRC-licensed facilities. Within the CSB there is a cyber assessment team that assesses real-world cyber events at NRC-licensed facilities. The team evaluates whether an identified threat could impact licensed facilities and makes recommendations for NRC actions and communications to the licensees. Furthermore, the NRC has established liaison relationships with the intelligence and law enforcement communities to include the National Counterterrorism Center, the DHSs U.S. Computer Emergency Response Team, and the Federal Bureau of Investigation. State T he BPU requires utilities, including PSEG, to, among other things, implement a cybersecurity program that defines and implements organizational accountabilities and responsibilities for cyber risk management activities, and establishes policies, plans, processes and procedures for identifying and mitigating cyber risk to critical systems. Additional requirements of this order include, but are not limited to (i) annually inventorying critical utility systems; (ii) annually assessing risks to critical utility systems; (iii) implementing controls to mitigate cyber risks to critical utility systems; (iv) monitoring log files of critical utility systems; (v) reporting cyber incidents to the BPU; and (vi) establishing a cybersecurity incident response plan and conducting biennial exercises to test the plan. In addition, New Yorks Stop Hacks and Improve Electronic Data Security (SHIELD) Act, which became effective in March 2020, requires businesses that own or license computerized data that includes New York State residents private information to implement reasonable safeguards to protect that information. ENVIRONMENTAL MATTERS We are subject to federal, state and local laws and regulations with regard to environmental matters. Our associated obligations change as legislatures and regulators pass new laws and regulations and amend existing ones. Therefore, it is difficult to project future costs of compliance and their impact on competition. Capital costs of complying with known pollution control requirements are included in our estimate of construction expenditures in Item 7. MDACapital Requirements. The costs of compliance associated with any new requirements that may be imposed by future regulations are not known, but may be material. For additional information related to environmental matters, including proceedings not discussed below, as well as anticipated expenditures for installation of compliance technology, hazardous substance liabilities and fuel and waste disposal costs, see Item 1A. Risk Factors and Item 8. Note 15. Commitments and Contingent Liabilities. Air Pollution Control Our facilities are subject to federal, state and local regulation that requires controls of emissions from sources of air pollution and imposes recordkeeping, reporting and permit requirements. Environmental Justice (EJ) The New Jersey Department of Environmental Protection (NJDEP) has issued an administrative order requiring an EJ review of certain environmental permit applications pending the promulgation of final EJ regulations that will provide additional guidance. The impacts of the NJDEPs actions are being evaluated for both PSEG and PSEG Power and the outcome cannot be determined at this time. New Jersey Protecting Against Climate Threats (NJ PACT) This NJDEP regulatory reform is expected to result in changes to existing air and land use regulations in response to anticipated impacts of climate change. It has published proposed changes pertaining to inland flood protection which are intended to protect new development from fluvial flooding. The final regulation is anticipated in 2023. We continue to assess the potential impact of the NJ PACT, which could have cost implications for business operations, including the construction of new facilities or upgrades to existing utility infrastructure. Such expenditures could materially affect the continued economic viability and/or cost to construct one or more such facilities. Water Pollution Control The Federal Water Pollution Control Act prohibits the discharge of pollutants from point sources to water, except pursuant to a duly issued permit. These permits must generally be renewed every five years. Applicable regulations also impose obligations on facility operators like PSEG Power to install certain technology to treat their discharges to ensure discharges meet certain water quality requirements. The Environmental Protection Agencys (EPA) Clean Water Act (CWA) Section 316(b) rule establishes requirements for the regulation of cooling water intakes at existing power plants, such as Salem. Hazardous Substance Liability PSEGs operations involve substances and byproducts classified by environmental regulations as hazardous. These regulations impose handling, storage and disposal requirements for hazardous materials. They also impose liability for damages to the environment, including cash penalties. Site Remediation Federal and state environmental laws and regulations require the cleanup of discharged hazardous substances. They authorize the EPA, the NJDEP and private parties to commence lawsuits to compel clean-ups or seek reimbursement for such remediation. The clean-ups can be more complicated and costly when the hazardous substances are in or under a body of water. Clean-up obligations may be imposed regardless of the absence of fault, contractual agreements between parties, or the legality of activities at the time of discharge. Natural Resource Damages Federal and state environmental laws and regulations authorize damage assessments against persons who have caused an injury to natural resources through the discharge of a hazardous substance. The NJDEP requires persons conducting remediation to address such injuries through restoration or damage assessments. Fuel and Waste Disposal Nuclear Fuel Disposal The federal government has entered into contracts with the operators of nuclear power plants for transportation and ultimate disposal of spent nuclear fuel. Under the Nuclear Waste Policy Act of 1982 (NWPA), nuclear plant owners are required to contribute to a Nuclear Waste Fund to pay for this service. Since May 2014, the nuclear waste fee rate has been zero. No assurances can be given that this fee will not be increased in the future. The NWPA allows spent nuclear fuel generated in any reactor to be stored in reactor facility storage pools or in Independent Spent Fuel Storage Installations located at reactors or away from reactor sites. We have on-site storage facilities that are expected to satisfy the storage needs of Salem 1, Salem 2, Hope Creek, Peach Bottom 2 and Peach Bottom 3 through the end of their operating licenses. Low-Level Radioactive Waste As a by-product of their operations, nuclear generation units produce low-level radioactive waste. Such waste includes paper, plastics, protective clothing, water purification materials and other materials. These waste materials are accumulated on site and disposed of at licensed permanent disposal facilities. New Jersey, Connecticut and South Carolina have reached an agreement that gives New Jersey nuclear generators continued access to a waste disposal facility which is owned by South Carolina. We believe that this agreement will provide for adequate low-level radioactive waste disposal for Salem and Hope Creek through the end of their current licenses including full decommissioning, although no assurances can be given. Low-Level Radioactive Waste is periodically being shipped to the South Carolina waste disposal facility from Salem and Hope

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Creek. Additionally, there are on-site storage facilities for Salem, Hope Creek and Peach Bottom, which we believe have the capacity for at least five years of temporary storage for each facility. INFORMATION ABOUT OUR EXECUTIVE OFFICERS (PSEG) ##TABLE_START Name Age as of December 31, 2022 Office Effective Date First Elected to Present Position Ralph A. LaRossa 59 President and Chief Executive Officer (CEO) -PSEG (A) September 2022 to present Chair of the Board (COB) and CEO - PSEG Power September 2022 to present Chief Operating Officer (COO) - PSEG January 2020 to August 2022 COB and CEO - PSEG September 2022 to present COB and CEO - PSEG Power September 2022 to present COB and CEO - Energy Holdings September 2022 to present COB and President - Services September 2022 to present President and COO - PSEG Power October 2017 to August 2022 President and COO - PSEG October 2006 to October 2017 COB - PSEG Long Island LLC December 2020 to August 2022 Eric Carr 48 President and COO - PSEG Power September 2022 to present President and Chief Nuclear Officer - PSEG Nuclear LLC July 2019 to present Vice President (VP) Hope Creek Generating Station - PSEG Nuclear LLC September 2016 to July 2019 Daniel J. Cregg 59 Executive Vice President (EVP) and Chief Financial Officer (CFO) - PSEG October 2015 to present EVP and CFO - PSEG October 2015 to present EVP and CFO - PSEG Power October 2015 to present Kim C. Hanemann 59 President and COO - PSEG June 2021 to present Senior Vice President (SVP) and COO - PSEG January 2020 to June 2021 SVP - Electric Transmission and Distribution - PSEG September 2018 to January 2020 SVP - Delivery, Projects and Construction - PSEG July 2014 to September 2018 VP - Delivery, Projects and Construction - PSEG December 2010 to July 2014 Tamara L. Linde 58 EVP and General Counsel - PSEG July 2014 to present EVP and General Counsel - PSEG July 2014 to present EVP and General Counsel - PSEG Power July 2014 to present Sheila J. Rostiac 52 SVP - Human Resources, Chief Human Resources and Chief Diversity Officer - Services January 2020 to present SVP - Human Resources and Chief Human Resources Officer - Services September 2019 to January 2020 VP - Talent, Development and Diversity October 2012 to September 2019 Richard T. Thigpen 62 SVP - Corporate Citizenship - Services July 2018 to present VP - State Government Affairs - Services March 2007 to July 2018 Rose M. Chernick 59 VP and Controller - PSEG March 2019 to present VP and Controller - PSEG March 2019 to present VP and Controller - PSEG Power March 2019 to present VP-Finance, Corporate Strategy and Planning - Services November 2017 to March 2019 VP-Finance, Holdings and Corporate Strategy and Planning - Services October 2015 to November 2017 ##TABLE_END(A) Effective January 1, 2023, in accordance with a management transition plan, Ralph A. LaRossa became COB of PSEG. ITEM 1A. RISK FACTORS The following factors should be considered when reviewing our business. These factors could have a material adverse impact on our business, prospects, financial position, results of operations or cash flows and could cause results to differ materially from those expressed elsewhere in this report. GENERAL OPERATIONAL AND FINANCIAL RISKS Inability to successfully develop, obtain regulatory approval for, or construct TD, and other generation projects could adversely impact our businesses. Our business plan calls for extensive investment in capital improvements and additions, including the construction of TD facilities, modernizing existing infrastructure pursuant to investment programs that provide for current recovery in rates, and our CEF programs, which include providing incentives for customers to install high-efficiency equipment at their premises, constructing EV infrastructure, and implementing our smart meter program. Currently, we have several significant projects underway or being contemplated. The successful construction and development of these projects will depend, in part, on our ability to: obtain necessary governmental and regulatory approvals; obtain environmental permits and approvals; obtain community support for such projects to avoid delays in the receipt of permits and approvals from regulatory authorities; obtain customer support for investments made at their premises; obtain property/land rights in property-constrained areas and at a reasonable cost; complete such projects within budgets and on commercially reasonable terms and conditions; complete supporting IT upgrades; obtain any necessary debt financing on acceptable terms and/or necessary governmental financial incentives; ensure that contracting parties, including suppliers, perform under their contracts in a timely and cost effective manner; and recover the related costs through rates. Any delays, cost escalations or otherwise unsuccessful construction and development could materially affect our financial position, results of operations and cash flows. Macroeconomic considerations, including inflationary levels, gas and electric supply prices that are passed through to customers and other pressures could factor into our regulators assessment in approving the size, duration and timing of cost recovery of certain of these programs. Further, certain negative public and political views on natural gas could result in diminishing political support for utility investments in gas infrastructure. In addition, the successful operation of new facilities or transmission or distribution projects is subject to risks relating to supply interruptions; labor availability, work stoppages and labor disputes; weather interferences; unforeseen engineering and environmental problems, including those related to climate change; opposition from local communities, and the other risks described herein. Any of these risks could cause our return on these investments to be lower than expected or they could cause these facilities to operate below intended targets, which could adversely impact our financial condition and results of operations through lost revenue and/or increased expenses. We are subject to physical, financial and transition risks related to climate change, including potentially increased legislative and regulatory burdens and changing customer preferences, and we may be subject to lawsuits, all of which could impact our businesses and results of operations, as well as our ability to implement our clean energy strategy. Climate change may increasingly drive change to existing or additional legislation and regulation that may impact our business and shape our customers energy preference and sustainability goals. While the CIP protects margin variances against changes in customer usage of gas and electricity, customer demand for natural gas could decrease as a result of changing customer preferences favoring electrification and advanced technologies that offer energy efficient options. Electric usage could also be impacted by greater adoption of EVs, installation of distributed energy resources, such as behind the meter solar, installation of more energy efficient equipment, flexible load and/or energy storage, and other advances in technology. Further, climate change may adversely impact the economy and reduced economic and consumer activity in our service areas could lower demand for electricity and gas we deliver. Any one or all of these factors could impact the need to invest in our electric and gas TD systems and, therefore, the rate of growth of our company. Severe weather or acts of nature, including hurricanes, winter storms, earthquakes, floods and other natural disasters can stress systems, disrupt operation of our facilities and cause service outages, production delays and property damage that require incurring additional expenses. These and other physical changes could result in changes in customer demand, increased costs associated with repairing and maintaining generation facilities and TD systems, resulting in increased maintenance and capital costs (and potential increased financing needs), increased regulatory oversight, and lower customer satisfaction. Where recovery of costs to restore service and repair damaged equipment and facilities is available, any determination by the regulator not to permit timely and full recovery of the costs incurred could have a material adverse effect on our businesses, financial condition, results of operations and prospects. To the extent financial markets view climate change and greenhouse gas (GHG) emissions as a financial risk, our ability to access capital markets could be negatively affected or cause us to receive less than favorable terms and conditions. Climate change-related political action and state and federal policy goals, including but not limited to those related to energy efficient targets, solar targets, energy storage targets, encouragement of electrification through EV adoption, policies to restrict the use of natural gas in new or existing homes and businesses, or encourage electrification of end use equipment currently fueled by natural gas, and the associated legislative and regulatory responses, may create financial risk as our operations may be subject to additional regulation at either the state or federal level in the future. Increased regulation of GHG emissions could impose significant additional costs on our electric and natural gas operations, and our suppliers. Developing and implementing plans for compliance with GHG emissions reduction, clean/renewable energy requirements, or for achieving voluntary climate commitments can lead to additional capital, personnel, and Operation and Maintenance (OM) expenditures and could significantly affect the economic position of existing operations and proposed projects. If our regulators do not allow us to recover all or a part of the cost of capital investment or the OM costs incurred to comply increasingly rigorous regulatory mandates, it could have a material adverse effect on our results of operations, financial condition or cash flows. On the other hand, in the event that the political, policy, regulatory or legislative support for clean energy projects declines, the benefits or feasibility of certain investments we may have made in such projects, including those in the development stage, may be reduced. We may be subject to climate change lawsuits that may seek injunctive relief, monetary compensation, and punitive damages, including but not limited to, for liabilities for personal injuries and property damage caused by climate change. An adverse outcome could require substantial capital expenditures and possibly require payment of substantial penalties or damages. Defense costs associated with such litigation can also be significant and could affect results of operations, financial condition or cash flows if such costs are not recovered through regulated rates . Further, our business is subject to policy, regulatory, technology and economic uncertainties and contingencies, including regulatory approvals required for various of our clean energy initiatives, many of which are beyond our control and may affect our ability to implement our clean energy strategy and initiatives and achieve our goal of net zero GHG emissions by 2030, or other GHG emissions reduction or climate-related goals that we may set from time to time, in a cost-effective manner or at all. We may be adversely affected by asset and equipment failures, critical operating technology or business system failures, accidents, natural disasters, severe weather events, acts of war or terrorism or other acts of violence, sabotage, physical attacks or security breaches, cyberattacks, or other incidents, including pandemics such as the coronavirus pandemic, that impact our ability to provide safe and reliable service to our customers and remain competitive and could result in substantial financial losses. The success of our businesses is dependent on our ability to continue providing safe and reliable service to our customers while minimizing service disruptions. We are exposed to the risk of asset and equipment failures, gas explosions, accidents, natural disasters, severe weather events, acts of war or terrorism or other acts of violence, including active shooter situations (such as the shooting incident involving an employee and a former employee which occurred in February 2023 outside of a PSEG field facility in Somerset County, New Jersey), sabotage, physical attacks or security breaches (as have been experienced recently by certain other utilities), cyberattacks or other incidents, which could result in damage to or destruction of our substations or other facilities or infrastructure, or damage to persons or property and to electric and gas supply interruptions. Further, a major failure of availability or performance of a critical operating technology or business system, and inadequate preparation or execution of business continuity or disaster recovery plans for the loss of one or several critical systems, could result in extended disruption to operations or business processes, damage to systems and/or loss of data . We have historically benefited from access to mutual aid, a voluntary and reciprocal arrangement with other utilities that provides access to a trained and flexible labor force which has helped to reduce outage restoration times during extreme weather events. There is no guarantee that we will have continued access to mutual aid as the utility industry consolidates and the frequency of severe weather events rises. We are also exposed to the risk of pandemics, such as the coronavirus pandemic, which could result in service disruptions and delay or otherwise impair our ability to timely provide service to our customers or complete our investment projects. These events could result in increased political, economic, financial and insurance market instability and volatility in power and fuel markets, which could materially adversely affect our business and results of operations, including our ability to access capital on terms and conditions acceptable to us. In addition, the effects of climate change will have increased the physical risks to our facilities and operations resulting from such climate hazards as more severe weather events (extreme wind, rainfall and flooding), such as experienced from Superstorm Sandy and Tropical Storms Isaias and Ida, sea level rise, and extreme heat. Any of the issues described above, if experienced at our facilities, or by others in our industry, could adversely impact our revenues; increase costs to repair and maintain our systems; subject us to potential litigation and/or damage claims, fines or penalties; and increase the level of oversight of our utility and generation operations and infrastructure through investigations or through the imposition of additional regulatory or legislative requirements. Such actions could adversely affect our costs, competitiveness and future investments, which could be material to our financial position, results of operations and cash flow. For our TD business, the cost of storm restoration efforts may not be fully recoverable through the regulatory process. In addition, the inability to restore power to our customers on a timely basis could result in negative publicity and materially damage our reputation. Any inability to recover the carrying amount of our long-lived assets could result in future impairment charges which could have a material adverse impact on our financial condition and results of operations. Long-lived assets represent approximately 74% and 82% of the total assets of PSEG and PSEG, respectively, as of December 31, 2022. Management evaluates long-lived assets for impairment whenever events or changes in circumstances, such as significant adverse changes in regulation, including a disallowance of certain costs, business climate or market conditions, including prolonged periods of adverse commodity and capacity prices, could potentially indicate an assets or group of assets carrying amount may not be recoverable. Significant reductions in our expected revenues or cash flows for an extended period of time resulting from such events could result in future asset impairment charges, which could have a material adverse impact on our financial condition and results of operations. Disruptions or cost increases in our supply chain, including labor shortages, could materially impact our business. The supply chain of goods and services is currently being negatively impacted by several factors, including manufacturing labor shortages, domestic and international shipping constraints, increases in demand, and shortages of raw materials and specialty components. As a result, we are seeing price increases in some areas and delivery delays of certain goods. These factors have increased our costs and have the potential to impact our operations. We cannot currently estimate the potential impact of continued supply chain disruptions but they could materially impact our business and results of operations. Inability to maintain sufficient liquidity in the amounts and at the times needed or access sufficient capital at reasonable rates or on commercially reasonable terms could adversely impact our business. Funding for our investments in capital improvement and additions, scheduled payments of principal and interest on our existing indebtedness and the extension and refinancing of such indebtedness has been provided primarily by internally-generated cash flow and external debt financings. We have significant capital requirements and depend on our ability to generate cash in the future from our operations and continued access to capital and bank markets to efficiently fund our cash flow needs. Our ability to generate cash flow is dependent upon, among other things, industry conditions and general economic, financial, competitive, legislative, regulatory and other factors. The ability to arrange financing and to refinance existing debt and the costs of such financing or refinancing depend on numerous factors including, among other things: general economic and capital market conditions, including but not limited to, prevailing interest rates; the availability of credit from banks and other financial institutions; tax, regulatory and securities law developments; for PSEG, our ability to obtain necessary regulatory approvals for the incurrence of additional indebtedness; investor confidence in us and our industry; our current level of indebtedness and compliance with covenants in our debt agreements; the success of current projects and the quality of new projects; our current and future capital structure; our financial performance and the continued reliable operation of our business; and maintenance of our investment grade credit ratings. Market disruptions, such as economic downturns experienced in the U.S. and abroad, the bankruptcy of an unrelated energy company or a systemically important financial institution, changes in market prices for electricity and gas, and actual or threatened acts of war or terrorist attacks, may increase our cost of borrowing or adversely affect our ability to access capital. As a result, no assurance can be given that we will be successful in obtaining financing for projects and investments, extending or refinancing maturing debt or meeting our other cash flow needs on acceptable terms or at all, which could materially adversely impact our financial position, results of operations and future growth. During periods of rising energy prices, hedged positions could be out-of-the-money, increasing PSEG Powers collateral requirements. In addition, if PSEG Power were to lose its investment grade credit rating from SP or Moodys, it would be required under certain agreements to provide a significant amount of additional collateral in the form of letters of credit or cash, which would have a material adverse effect on our liquidity and cash flows. Cybersecurity attacks or intrusions or other disruptions to our IT, operational or other systems could adversely impact our businesses. Cybersecurity threats to the energy market infrastructure are increasing in sophistication, magnitude and frequency, particularly since the coronavirus pandemic and the resulting shift to virtual operations began. Because of the inherent vulnerability of infrastructure and technology and operational systems to disability or failure due to hacking, viruses, malicious or destructive code, phishing and other social engineering attacks, denial of service attacks, ransomware, acts of war or terrorism, or other cybersecurity incidents, we face increased risk of cyberattack. We rely on information and operational technology systems and network infrastructure to operate our generation and TD systems. We also store sensitive data, intellectual property and proprietary or personally identifiable information regarding our business, infrastructure, employees, shareholders, customers and vendors on our IT systems and conduct power marketing and hedging activities. In addition, the operation of our business is dependent upon the IT systems of third parties, including our vendors, regulators, RTOs and ISOs, among others. Our and third-party operational and IT systems and products may be vulnerable to cybersecurity attacks involving fraud, malice or oversight on the part of our employees, other insiders or third parties, whether domestic or foreign sources. A successful cybersecurity attack may result in unauthorized use of our systems to cause disruptions at a third party. Cybersecurity risks to our operations include: disruption of the operation of our assets, the fuel supply chain, the power grid and gas TD, theft of confidential company, employee, shareholder, vendor or customer information, and critical energy infrastructure information, which may cause us to be in breach of certain covenants and contractual or legal obligations and pose risk to our system and our customers, general business system and process interruption or compromise, including preventing us from servicing our customers, collecting revenues or the ability to record, process and/or report financial information correctly, and breaches of vendors infrastructures where our confidential information is stored. We and our third-party vendors have been and will continue to be subject to cybersecurity attacks, including but not limited to ransomware, denial of service, business email compromises, and malware attacks. While there has been no material impact on our business or operations from these attacks to date, we may be unable to prevent all such attacks in the future from having such a material impact as such attacks continue to increase in sophistication and frequency. If a significant cybersecurity event or breach occurs within our company or with one of our material vendors, we could be exposed to significant loss of revenue, material repair costs to intellectual and physical property, significant fines and penalties if determined that we were in non-compliance with existing laws and regulations, significant litigation costs, increased costs to finance our businesses, negative publicity, damage to our reputation and loss of confidence from our customers, regulators, investors, vendors and employees. The misappropriation, corruption or loss of personally identifiable information and other confidential data from us or one of our vendors could lead to significant breach notification expenses, mitigation expenses such as credit monitoring, and legal and regulatory fines and penalties. Moreover, new or updated security laws or regulations or unforeseen threat sources could require changes in current measures taken by us and our business operations, which could result in increased costs and adversely affect our financial statements. Similarly, a significant cybersecurity event or breach experienced by a competitor, regulatory authority, RTO, ISO, or vendor could also materially impact our business and results of operations via enhanced legal and regulatory requirements. The amount and scope of insurance we maintain against losses that result from cybersecurity incidents may not be sufficient to cover losses or adequately compensate for resulting business disruptions. For a discussion of state and federal cybersecurity regulatory requirements and information regarding our cybersecurity program, see Item 1. BusinessRegulatory IssuesCybersecurity. A material shift away from natural gas toward increased electrification and a reduction in the use of natural gas as a result of economic decarbonization measures could adversely impact our business. Technological advancements enabling customer choice and state climate policy supporting decarbonization are driving transformative change in the electric power industry. New Jersey utilities are experiencing increased usage by customers and third parties of distributed energy resources, such as on-site solar generation, energy storage, fuel cells, EE, and demand response technologies. These developments will require modernization of the electric distribution grid to, among other things, accommodate two-way flows of electricity, increase the grids capacity, and interconnect distributed energy resources. In order to enable the New Jersey clean energy economy, sustained investments are required in grid modernization, renewable integration projects, EE programs, energy storage options, EV infrastructure and state infrastructure modernization. If these changes progressed in the near-term, our business model and our ability to execute on our strategy could be materially impacted. Various jurisdictions outside of New Jersey have enacted prohibitions or restrictions on the use and consumption of natural gas that will reduce the use of natural gas. If New Jersey were to enact similar prohibitions or restrictions, a reduction in the use of natural gas could lead to a reduction in the gas customer base, higher customer rates for those customers who remain, and a diminished need for gas infrastructure, which could potentially cause substantial investment value of gas assets to be stranded and removed from our rate base, resulting in a reduction in associated rate recovery. Our inability to recover through rates our investments into the natural gas system, while still ensuring gas system safety and reliability, could materially affect our financial condition, results of operations, liquidity, and cash flows. Further, these industry changes, costs associated with complying with new regulatory developments and initiatives and with technological advancements could materially affect our financial condition, results of operations, liquidity, and cash flows. Our financial condition and results of operations could be adversely affected by the coronavirus pandemic. In response to the global coronavirus pandemic, we have implemented a comprehensive set of actions to help our customers, communities and employees, and will continue to closely monitor developments and adjust as needed to ensure reliable service while protecting the safety and health of our workforce and the communities we serve. The pandemics potential impact will depend on a number of factors outside of our control, including the duration and severity of the outbreak as well as third-party actions, including governmental requirements. Pursuant to a BPU order, we have deferred a significant amount of costs for future recovery. Any inability to obtain timely recovery of these costs could have a material adverse effect on our business. Further, a number of expanded customer protection measures have been implemented by the State and the BPU, such as an extended moratorium on shut-offs of residential service for non-payment, and more extensive processes to be taken prior to any shut-off of service. These actions have negatively affected customer payment patterns, leading to an elevated aged accounts receivable balance. Our ability to manage our accounts receivable balance, recover its carrying costs and any associated bad debts could have a material impact on our business. We currently cannot estimate the potential impact the coronavirus pandemic may have on our business, results of operations, financial condition, liquidity and cash flows. The impacts of the pandemic and associated government and regulatory responses, including the long-term impact they may have on the economy, which could extend beyond the duration of the pandemic, could affect, among other things: PSEGs residential and CI customer payment patterns, in part as residential customer non-safety related service disconnections for non-payment were temporarily suspended for an extended period, resulting in adverse impacts to accounts receivable and bad debt expense; the recovery of incremental costs incurred related to the pandemic, including higher bad debts; and the availability of materials and supplies due to supply chain interruptions. Failure to attract and retain a qualified workforce could have an adverse effect on our business . Certain events such as an aging workforce looking to retire without an opportunity to transfer knowledge to a successor, inadequate workforce plans and replacements, lack of skill set to meet current and evolving business needs, a culture that does not foster inclusion leading to turnover, a workforce strike resulting from a failure to successfully negotiate new collective bargaining agreements with our labor unions on mutually acceptable terms or at all, unavailability of resources due to the coronavirus pandemic, acts of violence in the workplace and a workforce that is not engaged may lead to operating challenges and increased costs. The challenges include loss of knowledge and a lengthy time period associated with skill development, increased turnover, costs for contractors to replace employees, poor productivity, and a lack of innovation. Specialized knowledge and experience are required of employees across PSEG and its affiliates. There is competition for these skilled employees. Failure to hire and adequately train and retain employees, including the transfer of significant historical knowledge and expertise to new employees, may adversely affect our results of operations, financial position and cash flows. Increases in the costs of equipment and materials, fuel, services and labor could adversely affect our operating results. Inflation has recently increased across the economy and is impacting portions of our business. Higher costs from suppliers of equipment and materials, fuel, services and labor costs to attract and retain our workforce, could lead to increased costs, which could reduce our earnings. Also, seeking recovery of higher costs in future rate cases could pressure customer rates, resulting in a potentially adverse outcome of such proceedings, or in other proceedings, including the proposal of certain investment programs or other proceedings that impact customer rates. Covenants in our debt instruments and credit agreements may adversely affect our business. PSEGs and PSEGs fixed income debt instruments contain events of default customary for financings of their type, including cross accelerations to other debt of that entity. PSEGs, PSEGs and PSEG Powers bank credit agreements contain events of default customary for financings of their type, including cross defaults and accelerations and, in the case of PSEGs and PSEG Powers bank credit agreements, certain change of control events. PSEGs PSEGs and PSEG Powers bank credit agreements, contain certain limitations on the incurrence of liens and PSEG Powers bank credit agreements also contain limitations on the incurrence of certain subsidiary debt. The PSEG Power term loan agreement contains a change-of-control clause, which includes PSEG Power ceasing to be a wholly owned subsidiary of PSEG. Our ability to comply with these covenants may be affected by events beyond our control. If we fail to comply with the covenants and are unable to obtain a waiver or amendment, or a default exists and is continuing under such debt, the lenders or the holders or trustee of such debt, as applicable, could give notice and declare outstanding borrowings and other obligations under such debt immediately due and payable. We may not be able to obtain waivers, amendments or alternative financing, or if obtainable, it could be on terms that are not acceptable to us. Any of these events could adversely impact our financial condition, results of operations and cash flows. Financial market performance directly affects the asset values of our defined benefit plan trust funds and Nuclear Decommissioning Trust (NDT) Fund. Market performance and other factors could decrease the value of trust assets and could result in the need for significant additional funding. The performance of the financial markets will affect the value of the assets that are held in trust to satisfy our future obligations under our defined benefit plans and to decommission our nuclear generating plants. A decline in the market value of the defined benefit plan trust funds could increase our pension plan funding requirements and result in increased pension costs in future years. The market value of our defined benefit plan trusts could be negatively impacted by adverse financial market conditions that reduce the return on trust assets, decreased interest rates used to measure the required minimum funding levels, and future government regulation. Additional funding requirements for our defined benefit plans could be caused by changes in required or voluntary contributions, an increase in the number of employees becoming eligible to retire and changes in life expectancy assumptions. A decline in the market value of our NDT Fund could increase PSEG Powers funding requirements to decommission its nuclear plants. An increase in projected costs could also lead to additional funding requirements for our decommissioning trust. Failure to manage adequately our investments in our defined benefit plan trusts and NDT Fund could result in the need for us to make significant cash contributions in the future to maintain our funding at sufficient levels, which would negatively impact our results of operations, cash flows and financial position. RISKS RELATED TO OUR GENERATION BUSINESS Fluctuations in the wholesale power and natural gas markets could negatively affect our financial condition, results of operations and cash flows. In the competitive markets where we operate, natural gas prices have a major impact on the price that generators receive for their output and participants are not guaranteed any specific rate of return on their capital investments. Recently, the natural gas market and, therefore, energy markets have become more volatile due to higher domestic demand, increased natural gas exports and impacts from the global liquefied natural gas market, among other things. The price of natural gas is the primary driver of energy pricing in PJM. As such, the volatility in the natural gas market and potential lower natural gas prices may impact our results of operations and cash flows. Lower natural gas prices result in lower electricity prices, which reduce our margins where our nuclear generation costs may not have declined similarly. Changes in prevailing market prices could have a material adverse effect on our financial condition and results of operations. Factors that may cause market price fluctuations include: increases and decreases in generation capacity, including the addition of new supplies of power as a result of the development of new power plants, expansion of existing power plants or additional transmission capacity; severe weather conditions; power supply disruptions, including power plant outages and transmission disruptions; climate change and weather conditions, particularly unusually mild summers or warm winters in our market areas; seasonal fluctuations; economic and political conditions that could negatively impact the demand for power; changes in the supply of, and demand for, energy commodities; development of new fuels or new technologies for the production or storage of power; incurring penalties due to generation performance failure when called on by PJM during emergency situations; federal and state regulations and actions of PJM and changing PJM market rules; and federal and state power, market and environmental regulation and legislation, including financial incentives for new renewable energy generation capacity that could lead to oversupply and price suppression. Our generation business frequently involves the establishment of forward sale positions in the wholesale energy markets on long-term and short-term bases. To the extent that we have produced or purchased energy in excess of our contracted obligations, a reduction in market prices could reduce profitability. Conversely, to the extent that we have contracted obligations in excess of energy we have produced or purchased, an increase in market prices could reduce profitability. If the strategy we utilize to hedge our exposure to these various risks or if our internal policies and procedures designed to monitor the exposure to these various risks are not effective, we could incur material losses. Our market positions can also be adversely affected by the level of volatility in the energy markets that, in turn, depends on various factors, including weather in various geographical areas, short-term supply and demand imbalances, customer migration and pricing differentials at various geographic locations. These risks cannot be predicted with certainty. Increases in market prices also affect our ability to hedge generation output and fuel requirements as the obligation to post margin increases with increasing prices. In addition, the volatility and potential for higher natural gas prices may have a material impact on collateral requirements related to the forward value of our open futures contracts. Higher collateral requirements reduce available short-term liquidity and increase working capital costs. We may be unable to obtain an adequate fuel supply in the future. We obtain substantially all of our nuclear fuel supply from third parties pursuant to arrangements that vary in term, pricing structure, firmness and delivery flexibility. Our fuel supply arrangements must be coordinated with storage services and other contracts to ensure that the nuclear fuel is delivered to our power plants at the times, in the quantities and otherwise in a manner that meets the needs of our generation portfolio and our customers. We must also comply with laws and regulations governing the transportation of such fuels. We are exposed to increases in the price of nuclear fuel, and it is possible that sufficient supplies to operate our generating facilities profitably may not continue to be available to us. Significant changes in the price of nuclear fuel could affect our future results and impact our liquidity needs. In addition, we face risks with regard to the delivery to, and the use of nuclear fuel by, our power plants including the following: creditworthiness of third-party suppliers, defaults by third-party suppliers on supply obligations and our ability to replace supplies currently under contract may delay or prevent timely delivery; market liquidity for physical supplies of such fuels or availability of related services (e.g. fabrication) may be insufficient or available only at prices that are not acceptable to us; variation in the quality of such fuels may adversely affect our power plant operations; domestic and foreign legislative or regulatory actions or requirements may increase the cost of such fuels; and the loss of critical infrastructure, acts of war or terrorist attacks (including cybersecurity breaches) or catastrophic events such as fires, earthquakes, explosions, floods, severe storms or other similar occurrences could impede the delivery of such fuels. Our nuclear units have a diversified portfolio of contracts and inventory that provide a substantial portion of our fuel raw material needs over the next several years. However, each of our nuclear units has contracted with a single fuel fabrication services provider, and transitioning to an alternative provider could take an extended period of time. Certain of our other generation facilities also require fuel or other services that may only be available from one or a limited number of suppliers. The availability and price of this fuel may vary due to supplier financial or operational disruptions, transportation disruptions, force majeure and other factors, including market conditions. At times, such fuel may not be available at any price, or we may not be able to transport it to our facilities on a timely basis. In this case, we may not be able to run those facilities even if it would be profitable. If we had sold forward the power from such a facility, we could be required to supply or purchase power from alternate sources, perhaps at a loss. This could have a material adverse impact on our business, the financial results of specific plants and on our results of operations. Although our fuel contract portfolio provides a degree of hedging against these market risks, such hedging may not be effective and future increases in our fuel costs could materially and adversely affect our liquidity, financial condition and results of operations. While our generation runs on nuclear fuel, an increase in the cost of any particular fuel ultimately used by other generation facilities could impact our results of operations. The introduction or expansion of technologies related to energy generation, distribution and consumption and changes in customer usage patterns could adversely impact us. Federal and state incentives for the development and production of renewable sources of power have facilitated the penetration of competing technologies, such as wind, solar, and commercial-sized power storage. Additionally, the development of DSM and EE programs can impact demand requirements for some of our markets at certain times during the year. The continued development of subsidized, competing on-site power generation and storage technologies and significant development of DSM and EE programs could alter the market and price structure for power generation and could result in a reduction in load requirements, negatively impacting our financial condition, results of operations and cash flows. Technological advances driven by federal laws mandating new levels of EE in end-use electric devices or other improvements in, or applications of, technology could also lead to declines in per capita energy consumption. Advances in distributed generation technologies, such as fuel cells, micro turbines, micro grids, windmills and net-metered solar installations, may reduce the cost of alternative methods of producing electricity to a level that is competitive with that of most central station electric production. Large customers, such as universities and hospitals, continue to explore potential micro grid installation. Certain states, such as Massachusetts and California, are also considering mandating the use of power storage resources to replace uneconomic or retiring generation facilities. Such developments could (i) affect the price of energy, (ii) reduce energy deliveries as customer-owned generation becomes more cost-effective, (iii) require further improvements to our distribution systems to address changing load demands, and (iv) make portions of our transmission and/or distribution facilities obsolete prior to the end of their useful lives. These technologies could also result in further declines in commodity prices or demand for delivered energy. Several states, cities and other stakeholders are also considering bans on new natural gas customers and transitioning away from natural gas in the future. Such actions could have a material adverse effect on our business. Some or all of these factors could result in a lack of growth or decline in customer demand for electricity or number of customers, and may cause us to fail to fully realize anticipated benefits from significant capital investments and expenditures, which could have a material adverse effect on our financial position, results of operations and cash flows. These factors could also materially affect our results of operations, cash flows or financial positions through, among other things, reduced operating revenues, increased OM expenses, and increased capital expenditures, as well as potential asset impairment charges or accelerated depreciation and decommissioning expenses over shortened remaining asset useful lives. We are subject to third-party credit risk relating to our sale of nuclear generation output and purchase of nuclear fuel. We sell generation output and buy fuel through the execution of bilateral contracts. We also seek to contract in advance for a significant proportion of our anticipated output capacity and fuel needs. These contracts are subject to credit risk, which relates to the ability of our counterparties to meet their contractual obligations to us. Any failure of these counterparties to perform could require PSEG Power to purchase or sell energy or fuel in the wholesale markets at less favorable prices and incur additional losses, which could have a material adverse impact on our results of operations, cash flows and financial position. In the spot markets, we are exposed to the risks of the default sharing mechanisms that exist in those markets, some of which attempt to spread the risk across all participants. Therefore, a default by a third party could increase our costs, which could negatively impact our results of operations and cash flows. There may be periods when PSEG Power generation output may not be able to meet its commitments under forward sale obligations and PJM rules at a reasonable cost or at all. A substantial portion of PSEG Powers nuclear generation output has been sold forward under fixed price financial power sales contracts. Forward financial sales offset physical sales in the PJM RTO spot market. Our forward sales of energy and capacity assume sustained, acceptable levels of operating performance. Operations at any of our plants could degrade to the point where the plant has to shut down or operate at less than full capacity. Some issues that could impact the operation of our facilities are: breakdown or failure of equipment, IT, processes or management effectiveness; disruptions in the transmission of electricity; labor disputes or work stoppages; fuel supply interruptions; transportation constraints; limitations which may be imposed by environmental or other regulatory requirements; and operator error, acts of war or terrorist attacks (including cybersecurity breaches) or catastrophic events such as fires, earthquakes, explosions, floods, severe weather or other similar occurrences. Identifying and correcting any of these issues may require significant time and expense. Depending on the materiality of the issue, we may choose to close a plant rather than incur the expense of restarting it or returning it to full capacity. Because the obligations under most of these forward sale agreements are not contingent on a unit being available to generate power, PSEG Powers results of operations and cash flows are at risk even in the event of a plant outage, or a reduction in the available capacity of the unit. To the extent that PSEG Power does not meet its expected nuclear generation output, PSEG Power would be required to pay the difference between the market price and the contract price on its financial contracts without receiving the physical spot energy revenue or be required to purchase energy at higher prices to cover its shortfall. In addition, as capacity performance resources in PJM, PSEGs nuclear units have been and will in the future be required to pay penalties if a forced outage at a plant occurs during a declared emergency event within PJM and that plants expected performance exceeds its actual performance during such event. The amount of such payments could be substantial and could have a material adverse effect on our financial condition, results of operations and cash flows. In addition, as market prices for energy and fuel fluctuate, our forward energy sale and forward fuel purchase contracts could require us to post substantial additional collateral, thus requiring us to obtain additional sources of liquidity during periods when our ability to do so may be limited. Certain of our generation facilities rely on transmission facilities that we do not own or control and that may be subject to transmission constraints. Transmission facility owners inability to maintain adequate transmission capacity could restrict our ability to deliver wholesale electric power to our customers and we may either incur additional costs or forgo revenues. We depend on transmission facilities owned and operated by others to deliver the wholesale power we sell from our generation facilities. If transmission is disrupted or if the transmission capacity infrastructure is inadequate, our ability to sell and deliver wholesale power may be adversely impacted. If a regions power transmission infrastructure is inadequate, our recovery of wholesale costs and profits may be limited. In addition, in PJM, energy transmission congestion risk and associated costs exist. We may not be able to accurately predict and hedge this risk due to insufficient market data and liquidity. An increase in our congestion costs may adversely affect our financial results. REGULATORY, LEGISLATIVE AND LEGAL RISKS PSEGs revenues, earnings and results of operations are dependent upon state laws and regulations that affect distribution and related activities. PSEG is subject to regulation by the BPU. Such regulation affects almost every aspect of its businesses, including its retail rates. Failure to comply with these regulations could have a material adverse impact on PSEGs ability to operate its business and could result in fines, penalties or sanctions. The retail rates for electric and gas distribution services are established in a base rate proceeding and remain in effect until a new base rate proceeding is filed and concluded. In addition, our utility has received approval for several clause recovery mechanisms, some of which provide for recovery of costs and earn returns on authorized investments. These clause mechanisms require periodic updates to be reviewed and approved by the BPU and are subject to prudency reviews. Inability to obtain fair or timely recovery of all our costs, including a return of, or on, our investments in rates, could have a material adverse impact on our results of operations and cash flows. In addition, if legislative and regulatory structures were to evolve in such a way that PSEGs exclusive rights to serve its regulated customers were eroded, its future earnings could be negatively impacted. PSEG also is pursuing a number of opportunities to expand its products and services to customers to support clean energy goals. BPU approval is required for any new endeavor, and is not guaranteed. Rejection or delay of such filings could have an adverse impact on our future growth, or our standing with environmentally conscious investors or other stakeholders. In September 2020, the BPU ordered the commencement of a comprehensive affiliate and management audit of PSEG. The BPU also conducts periodic combined management/competitive service audits of New Jersey utilities related to affiliate standard requirements, competitive services, cross-subsidization, cost allocation and other issues. A finding by the BPU of non-compliance with these requirements could potentially impact our business, results of operations and cash flows. For information regarding PSEGs current affiliate and management audit, see Item 8. Note 15. Commitments and Contingent Liabilities. In addition, PSEG procures the supply requirements of its default service BGSS gas customers through a full-requirements contract with PSEG Power. Government officials, legislators and advocacy groups are aware of the affiliation between PSEG and PSEG Power. In periods of rising utility rates, those officials and advocacy groups may question or challenge costs and transactions incurred by PSEG with PSEG Power, irrespective of any previous regulatory processes or approvals underlying those transactions. The occurrence of such challenges may subject PSEG Power to a level of scrutiny not faced by other unaffiliated competitors in those markets and could adversely affect retail rates received by PSEG in an effort to offset any perceived benefit to PSEG Power from the affiliation. PSEGs proposed investment programs may not be fully approved by regulators, which could result in lower than desired service levels to customers, and actual capital investment by PSEG may be lower than planned, which would cause lower than anticipated rate base. PSEG is a regulated public utility that operates and invests in an electric TD system and a gas distribution system as well as certain regulated clean energy investments, including solar and EE within New Jersey. PSEG invests in capital projects to maintain and improve its existing TD system and to address various public policy goals and meet customer expectations. Transmission projects are subject to a FERC-approved transmission expansion planning process while distribution and clean energy projects are subject to approval by the BPU. The costs of PSEGs transmission projects are subject to prudency challenge at FERC and PSEGs rates themselves may also be challenged at FERC. We cannot be certain that any proposed project will be approved as requested or at all. If the programs that PSEG may file from time to time are only approved in part, or not at all, or if the approval fails to allow for the timely recovery of all of PSEGs costs, including a return of, or on, its investment, PSEG will have a lower than anticipated rate base, thus causing its future earnings to be lower than anticipated. If these programs are not approved, that could also adversely affect our service levels for customers. Further, the BPU could take positions to exclude or limit utility participation in certain areas, such as renewable generation, EE, EV infrastructure, energy storage, renewable natural gas or hydrogen projects, which would limit our relationship with customers and narrow our future growth prospects. We are subject to comprehensive federal regulation that affects, or may affect, our businesses. We are subject to regulation by federal authorities. Such regulation affects almost every aspect of our businesses, including management and operations; the terms and rates of transmission services; investment strategies; the financing of our operations and the payment of dividends. Failure to comply with these regulations could have a material adverse impact on our ability to operate our business and could result in fines, penalties or sanctions. Recovery of wholesale transmission rates PSEGs wholesale transmission rates are regulated by FERC and are recovered through a FERC-approved formula rate. The revenue requirements are reset each year through this formula. In 2021, FERC approved a settlement agreement effective August 1, 2021 that we reached with the BPU and the New Jersey Rate Counsel about the level of PSEGs base transmission ROE and other formula rate matters. The settlement reduces PSEGs base ROE from 11.18% to 9.9% and made changes to recovery of certain costs. The agreement provides that the settling parties will not seek changes to our transmission formula rate for three years. We have implemented the terms of the agreement . In April 2021, FERC issued a supplemental notice of proposed rulemaking to eliminate the incentive for RTO membership for transmitting utilities that have already received the incentive for three or more years. PSEG began receiving a 50 basis point adder for RTO membership in 2008. Elimination of the adder for RTO membership would reduce PSEGs annual Net Income and annual cash inflows by approximately $30 million-$40 million. Transmission Planning FERC Order 1000 has generally opened transmission development to competition from independent developers, allowing such developers to compete with incumbent utilities for the construction and operation of transmission facilities in its service territory. While Order 1000 retains limited carve-outs for certain projects that will continue to default to incumbents for construction responsibility, including immediately needed reliability projects, upgrades to existing transmission facilities, projects cost-allocated to a single transmission zone, and projects being built on existing rights-of-way, increased competition for transmission projects could decrease the value of new investments that would be subject to recovery by PSEG under its rate base, which could have a material adverse impact on our financial condition and results of operations. FERC is currently considering whether to modify Order 1000s competition rules to further limit competition in an effort to encourage collaborative planning of large regional and interregional transmission projects. FERC is also examining whether additional oversight is needed to control transmission costs. NERC Compliance NERC, at the direction of FERC, has implemented mandatory NERC Operations and Planning and Critical Infrastructure Protection standards to ensure the reliability of the North American Bulk Electric System, which includes electric transmission and generation systems, and to prevent major system blackouts. NERC Critical Infrastructure Protection standards establish cybersecurity and physical security protections for critical systems and facilities. We have been, and will continue to be, periodically audited by NERC for compliance with both Operations and Planning and Critical Infrastructure Protection standards and are subject to penalties for non-compliance with applicable NERC standards. NERC is conducting more frequent audits than was the case in the past and we must always be in a state of audit readiness. Failure to comply with applicable NERC standards could result in penalties or increased costs to bring such facilities into compliance. Such penalties and costs could materially adversely impact our business, results of operations and cash flows. Adverse audit findings and/or penalties for non-compliance also pose reputational risk to us. MBR Authority and Other Regulatory Approvals Under FERC regulations, public utilities that sell power at market rates must receive MBR authority before making power sales, and the majority of our businesses operate with such authority. Failure to maintain MBR authorization, or the effects of any severe mitigation measures that would be required if market power was evaluated differently in the future, could have a material adverse effect on our business, financial condition and results of operations. In December 2022, all of PSEGs operating companies with MBR authority filed at FERC for acceptance of the companies updated triennial market power analysis. This filing remains pending at FERC. Oversight by the CFTC relating to derivative transactions The CFTC has regulatory oversight of the swap and futures markets and options, including energy trading, and licensed futures professionals such as brokers, clearing members and large traders. Changes to regulations or adoption of additional regulations by the CFTC, including any regulations relating to futures and other derivatives or margin for derivatives and increased investigations by the CFTC, could negatively impact PSEG Powers ability to hedge its portfolio in an efficient, cost-effective manner by, among other things, potentially decreasing liquidity in the forward commodity and derivatives markets or limiting PSEG Powers ability to utilize non-cash collateral for derivatives transactions. We may also be required to obtain various other regulatory approvals to, among other things, buy or sell assets, engage in transactions between our public utility and our other subsidiaries, and, in some cases, enter into financing arrangements, issue securities and allow our subsidiaries to pay dividends. Failure to obtain these approvals on a timely basis could materially adversely affect our results of operations and cash flows. The markets, PTC and/or ZEC program may not provide sufficient revenue for our New Jersey nuclear plants or the PTC and/or ZEC program could be materially adversely modified through legal proceedings, either of which could result in the retirement of all of these nuclear plants. As further described in Item 7. MDAExecutive Overview of 2022 and Future Outlook, in April 2019, PSEG Powers Salem 1, Salem 2 and Hope Creek nuclear plants were awarded ZECs by the BPU through May 2022. In April 2021, these nuclear plants were awarded ZECs for the three-year period starting June 2022. In May 2021, the New Jersey Rate Counsel filed an appeal with the New Jersey Appellate Division of the BPUs April 2021 decision. PSEG cannot predict the outcome of these matters. In August 2022, the IRA was signed into law expanding incentives promoting carbon-free generation. The enacted legislation established a PTC for electricity generation using nuclear energy set to begin in 2024 through 2032. The expected PTC rate is up to $15/MWh subject to adjustment based upon a facilitys gross receipts. The PTC rate and the gross receipts cap are subject to annual inflation adjustments. The U.S. Treasury is expected to clarify the definition of gross receipts prior to when the eligibility period begins in 2024. The ZEC payment may be adjusted by the BPU at any time to offset environmental or fuel diversity payments that a selected nuclear plant may receive from another source. We are continuing to analyze the impact of the IRA on our nuclear units including additional future guidance from the U.S. Treasury and the interactions with PTCs on expected ZEC payments. If the markets, PTC and/or the ZEC program do not provide sufficient revenue, or, in the case of the Salem nuclear plants, decisions by the EPA and state environmental regulators regarding the implementation of Section 316(b) of the CWA and related state regulations, or other factors, PSEG Power may take all necessary steps to cease to operate all of these plants and will incur associated costs and accounting charges in the event that the financial condition of the plants is materially adversely impacted in the future. Ceasing operations of these plants would result in a material adverse impact on PSEGs results of operations. We may be adversely affected by changes in energy regulatory policies, including energy and capacity market design rules and developments affecting transmission. The energy industry continues to be regulated and the rules to which our businesses are subject are always at risk of being changed. Our business has been impacted by established rules that create locational capacity markets in PJM. Under these rules, generators located in constrained areas are paid more for their capacity so there is an incentive to locate in those areas where generation capacity is most needed. PJMs capacity market design rules continue to evolve, including in response to efforts to integrate public policy initiatives into the wholesale markets. For a discussion of recent changes in energy regulatory policies that may affect our business and results of operations, see Item 1. Regulatory IssuesFederal Regulation. Further, some of the market-based mechanisms in which we participate are at times the subject of review or discussion by some of the participants in the New Jersey and federal arenas. We can provide no assurance that these mechanisms will continue to exist in their current form, nor otherwise be modified. In

July 2021, the BPU issued a report on its investigation related to whether New Jersey can achieve its long-term clean energy and environmental objectives under the current resource adequacy procurement paradigm. The report found that participating in the regional market is the most efficient way for New Jersey to achieve its clean energy goals and therefore consideration of leaving the regional market is paused while market reforms are being considered at the regional and national level. In September 2022, the BPU issued a Progress Report expanding on the recommendations contained in the 2021 report. The Progress Report found that it is in New Jerseys best interest to pursue a voluntary independent clean energy market and Staff sought the BPUs authorization to evaluate various options that would serve as alternatives to the PJM capacity market or work in conjunction with it. We cannot predict whether the BPU will ultimately take any measures in the future that will have an impact on the capacity market or our generating stations. Our ownership and operation of nuclear power plants involve regulatory risks as well as financial, environmental and health and safety risks. The vast majority of our total generation output each year is provided by our nuclear fleet. For this reason, we are exposed to risks related to the continued successful operation of our nuclear facilities and issues that may adversely affect the nuclear generation industry. In addition to the risk of retirement discussed below, risks associated with the operation of nuclear facilities include: Storage and Disposal of Spent Nuclear Fuel Federal law requires the United States Department of Energy (DOE) to provide for the permanent storage of spent nuclear fuel. The DOE has not yet begun accepting spent nuclear fuel. Until a federal site is available, we use on-site storage for spent nuclear fuel, which is reimbursed by the DOE. However, future capital expenditures may be required to increase spent fuel storage capacity at our nuclear facilities. Once a federal site is available, the DOE may impose fees to support a permanent repository. Further, the on-site storage for spent nuclear fuel may significantly increase our nuclear unit decommissioning costs. Regulatory and Legal Risk We may be required to substantially increase capital expenditures or operating or decommissioning costs at our nuclear facilities if there is a change in the Atomic Energy Act or the applicable regulations, trade controls or the environmental rules and regulations applicable to nuclear facilities; a modification, suspension or revocation of licenses issued by the NRC; the imposition of civil penalties for failure to comply with the Atomic Energy Act, related regulations, trade controls or the terms and conditions of the licenses for nuclear generating facilities; or the shutdown of one of our nuclear facilities. Any such event could have a material adverse effect on our financial condition or results of operations. Operational Risk Operations and equipment reliability at any of our nuclear facilities could degrade to the point where an affected unit needs to be shut down or operated at less than full capacity. If this were to happen, identifying and correcting the causes could require significant time and expense and a significant outage could result in reduced earnings as we would have less electric output to sell and would be required to deliver on our forward sale commitments. In addition, if a unit cannot be operated through the end of its current estimated useful life, our results of operations could be adversely affected by increased depreciation rates, impairment charges and accelerated future decommissioning costs. Nuclear Incident or Accident Risk Accidents and other unforeseen problems have occurred at nuclear stations, both in the U.S. and elsewhere. The consequences of an accident can be severe and may include loss of life, significant property damage and/or a change in the regulatory climate. We have nuclear units at two sites. It is possible that an accident or other incident at a nuclear generating unit could adversely affect our ability to continue to operate unaffected units located at the same site, which would further affect our financial condition, results of operations and cash flows. An accident or incident at a nuclear unit not owned by us could lead to increased regulation, which could affect our ability to continue to economically operate our units. Any resulting financial impact from a nuclear accident may exceed our resources, including insurance coverages. Further, as a licensed nuclear operator subject to the Price-Anderson Act and a member of a nuclear industry mutual insurance company, PSEG Power is subject to potential retroactive assessments as a result of an industry nuclear incident or retrospective premiums due to adverse industry loss experience and such assessments may be material. In the event of non-compliance with applicable legislation, regulation and licenses, the NRC may increase oversight, impose fines, and/or shut down a unit, depending on its assessment of the severity of the non-compliance. If a serious nuclear incident were to occur, our business, reputation, financial condition and results of operations could be materially adversely affected. In each case, the amount and types of insurance available to cover losses that might arise in connection with the operation of our nuclear fleet are limited and may be insufficient to cover any costs we may incur. Decommissioning NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available to decommission a nuclear facility at the end of its useful life. PSEG Nuclear has established an NDT Fund to satisfy these obligations. However, forecasting trust fund investment earnings and costs to decommission nuclear generating stations requires significant judgment, and actual results could differ significantly from current estimates. If we determine that it is necessary to retire one of our nuclear generating stations before the end of its useful life, there is a risk that it will no longer meet the NRC minimum funding requirements due to the earlier commencement of decommissioning activities and a shorter time period over which the NDT investments could appreciate in value. A shortfall could require PSEG to post parental guarantees or make additional cash contributions to ensure that the NDT Fund continues to satisfy the NRC minimum funding requirements. As a result, our financial position or cash flows could be significantly adversely affected. We are subject to numerous federal, state and local environmental laws and regulations that may significantly limit or affect our businesses, adversely impact our business plans or expose us to significant environmental fines and liabilities. We are subject to extensive federal, state and local environmental laws and regulations regarding air quality, water quality, site remediation, land use, waste disposal, climate change impact, natural resource damages and other matters. These laws and regulations affect how we conduct our operations and make capital expenditures. Over the past several years, there have been various changes to existing environmental laws and regulations and this trend may continue. Changes in these laws, or violations of laws, could result in significant increases in our compliance costs, capital expenditures to bring facilities into compliance, operating costs for remediation and clean-up actions, civil penalties or damages from actions brought by third parties for alleged health or property damages. Any such increase in our costs could have a material impact on our financial condition, results of operations and cash flows and could require further economic review to determine whether to continue operations or decommission an affected facility. We may also be unable to successfully recover certain of these cost increases through our existing regulatory rate structures, in the case of PSEG, or our contracts with our customers, in the case of PSEG Power. Actions by state and federal government agencies could also result in reduced reliance on natural gas and could potentially result in stranding natural gas assets owned and operated by PSEG Power and PSEG, which could materially adversely affect our business, financial condition and results of operations. PSEG recovers certain remediation and legal costs associated with its manufactured gas plant sites through Remediation Adjustment Charge (RAC) filings with the BPU. Continued future recoveries through the RAC are not guaranteed. Any failure to make future recoveries could materially impact our financial condition. In addition, PSEG Power retained ownership of certain liabilities excluded from the sale of its fossil generation portfolio. These primarily relate to obligations under environmental regulations, including remediation obligations under the New Jersey Industrial Site Recovery Act and the Connecticut Transfer Act. It will require multiple years and comprehensive environmental sampling to understand the extent of and to carry out the required remediation. The full remediation costs are not estimable, but will likely be material. Environmental laws and regulations have generally become more stringent over time, and this trend is likely to continue. For further discussion of environmental laws and regulations impacting our business, results of operations and financial condition, including the impact of federal and state laws and regulations relating to remediation of environmental contamination, see Item 8. Note 15. Commitments and Contingent Liabilities. We may not receive necessary licenses, permits and siting approvals in a timely manner or at all, which could adversely impact our business and results of operations. We must periodically apply for licenses and permits from various regulatory authorities, including environmental regulatory authorities, and abide by their respective orders. Delay in obtaining, or failure to obtain and maintain, any permits or approvals, including environmental permits or approvals, or delay in or failure to satisfy any applicable regulatory requirements, could: prevent construction of new facilities, limit or prevent continued operation of existing facilities, limit or prevent the sale of energy from these facilities, or result in significant additional costs, each of which could materially affect our business, financial condition, results of operations and cash flows. In addition, the process of obtaining licenses and permits from regulatory authorities may be delayed or defeated by concerted community opposition and such delay or defeat could have a material effect on our business. Changes in tax laws and regulations may adversely affect our financial condition, results of operations and cash flows. The enactment of additional federal or state tax legislation and clarification of previously enacted tax laws could have a material impact on our effective tax rate and cash tax position.

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##TABLE_START ##TABLE_ENDITEM 1. BUSINESS OVERVIEW We are a California-based holding company with energy infrastructure investments in North America. Our businesses invest in, develop and operate energy infrastructure, and provide electric and gas services to customers. Sempra was formed in 1998 through a business combination of Enova and PE, the holding companies of our regulated public utilities in California: SDGE, which began operations in 1881, and SoCalGas, which began operations in 1867. We have since expanded our regulated public utility presence into Texas through our 80.25% interest in Oncor and 50% interest in Sharyland Utilities. Sempra Infrastructures assets include investments in the U.S. and Mexico with a focus on LNG and net zero solutions, energy networks and clean power. Business Strategy Our mission is to be North Americas premier energy infrastructure company. We are primarily focused on transmission and distribution investments, among other areas, that we believe are capable of producing stable cash flows and earnings visibility, with the goal of delivering safe, reliable and increasingly clean forms of energy to customers and increasing shareholder value. DESCRIPTION OF BUSINESS BY SEGMENT Our business activities are organized under the following reportable segments: SDGE SoCalGas Sempra Texas Utilities Sempra Infrastructure SDGE SDGE is a regulated public utility that provides electric services to a population of, at December 31, 2022, approximately 3.6 million and natural gas services to approximately 3.3 million of that population, covering a 4,100 square mile service territory in Southern California that encompasses San Diego County and an adjacent portion of Orange County. 2022 Form 10-K | 13 Table of Contents SDGEs assets at December 31, 2022 covered the following territory: Electric Utility Operations Electric Transmission and Distribution System. Service to SDGEs customers is supported by its electric transmission and distribution system, which includes substations and overhead and underground lines. These electric facilities are primarily in the San Diego, Imperial and Orange counties of California, and in Arizona and Nevada and consisted of 1,928 miles of transmission lines, 23,928 miles of distribution lines and 157 substations at December 31, 2022. Occasionally, various areas of the service territory require expansion to accommodate customer growth and maintain reliability and safety. SDGEs 500-kV Southwest Powerlink transmission line, which is shared with Arizona Public Service Company and Imperial Irrigation District, extends from Palo Verde, Arizona to San Diego, California. SDGEs share of the line is 1,163 MW, although it can be less under certain system conditions. SDGEs Sunrise Powerlink is a 500-kV transmission line constructed by SDGE and operated by the California ISO. Both of these lines together provide SDGE with import capability of 3,900 MW of power. Mexicos Baja California transmission system is connected to SDGEs system via two 230-kV interconnections with combined capacity of up to 600 MW in the north-to-south direction and 800 MW in the south-to-north direction. However, it can be less under certain system conditions. Edisons transmission system is connected to SDGEs system via five 230-kV transmission lines. 2022 Form 10-K | 14 Table of Contents Electric Resources. To meet customer demand, SDGE supplies power from its own electric generation facilities and procures power on a long-term basis from other suppliers for resale through CPUC-approved purchased-power contracts or purchases on the spot market. SDGE does not earn any return on commodity sales volumes. SDGEs electric resources at December 31, 2022 were as follows: ##TABLE_START SDGE ELECTRIC RESOURCES (1) Contract Net operating expiration date capacity (MW) % of total Owned generation facilities, natural gas (2) 1,204 24 % Purchased-power contracts: Renewables: Wind 2023 to 2042 1,236 24 Solar 2030 to 2042 1,390 27 Other 2023 and thereafter 37 1 Tolling and other 2024 to 2042 1,206 24 Total 5,073 100 % ##TABLE_END(1) Excludes approximately 321 MW of energy storage owned and approximately 164 MW of energy storage contracted. (2) SDGE owns and operates four natural gas-fired power plants, three of which are in California and one is in Nevada. Charges under contracts with suppliers are based on the amount of energy received or are tolls based on available capacity. Tolling contracts are purchased-power contracts under which SDGE provides natural gas to the energy supplier. SDGE procures natural gas under short-term contracts for its owned generation facilities and for certain tolling contracts associated with purchased-power arrangements. Purchases from various southwestern U.S. suppliers are primarily priced based on published monthly bid-week indices, which can be subject to volatility. SDGE participates in the Western

Systems Power Pool, which includes an electric-power and transmission-rate agreement that allows access to power trading with more than 300 member utilities, power agencies, energy brokers and power marketers throughout the U.S. and Canada. Participants can make power transactions on standardized terms, including market-based rates, preapproved by the FERC. Participation in the Western Systems Power Pool is intended to assist members in managing power delivery and price risk. Customers and Demand. SDGE provides electric services through the generation, transmission and distribution of electricity to the following customer classes: ##TABLE_START SDGE ELECTRIC CUSTOMER METERS AND VOLUMES Customer meter count Volumes (1) (millions of kWh) December 31, Years ended December 31, 2022 2022 2021 2020 Residential 615,126 3,940 5,657 6,606 Commercial 71,661 2,850 4,128 5,873 Industrial 471 909 1,398 1,842 Street and highway lighting 3,323 101 115 77 690,581 7,800 11,298 14,398 CCA and DA 813,304 9,900 5,916 3,482 Total 1,503,885 17,700 17,214 17,880 ##TABLE_END(1) Includes intercompany sales. SDGE currently provides procurement service for a portion of its customer load. Most customers receive procurement service from a load-serving entity other than SDGE through programs such as CCA and DA. In such cases, SDGE no longer procures energy for this departing load. Accordingly, SDGEs CCA and DA customers receive primarily transportation and distribution services from SDGE. CCA is only available if the customers local jurisdiction (city or county) offers such a program and DA is currently limited by a cap based on gigawatt hours. Several jurisdictions in SDGE's territory have implemented CCA, including the City of San Diego in 2022. Additional jurisdictions are in the process of implementing or considering CCA. 2022 Form 10-K | 15 Table of Contents SDGEs historical energy procurement for future deliveries exceeds the needs of its remaining bundled customers as customers have elected CCA and DA services. To help achieve the goal of ratepayer indifference (as to whether or not customers energy is procured by SDGE or by CCA or DA), the CPUC revised the Power Charge Indifference Adjustment framework. The purpose of the framework is to help ensure SDGEs procurement cost obligations are more equitably shared among customers served by SDGE and customers now served by CCA or DA. SDGE implemented the framework on January 1, 2019. San Diegos mild climate and SDGEs robust energy efficiency programs contribute to lower consumption by our customers. Rooftop solar installations continue to reduce residential and commercial volumes sold by SDGE. At December 31, 2022, 2021 and 2020, the residential and commercial rooftop solar capacity in SDGEs territory totaled 1,864 MW, 1,620 MW and 1,423 MW, respectively. Electricity demand is dependent on the health and expansion of the Southern California economy, prices of alternative energy products, consumer preference, environmental regulations, legislation, renewable power generation, the effectiveness of energy efficiency programs, demand-side management impact and distributed generation resources. Californias energy policy supports increased electrification, particularly electrification of vehicles, which could significantly increase sales volumes in the coming years. Other external factors, such as the price of purchased power, the use of hydroelectric power, the use of and further development of renewable energy resources and energy storage, the development of or requirements for new natural gas supply sources, demand for and supply of natural gas and general economic conditions, can also result in significant shifts in the market price of electricity, which may in turn impact demand. Electricity demand is also impacted by seasonal weather patterns (or seasonality), tending to increase in the summer months to meet the cooling load and in the winter months to meet the heating load. Competition. SDGE faces competition to serve its customer load from distributed and local power generation growth, including solar installations. In addition, the electric industry is undergoing rapid technological change, and third-party energy storage alternatives and other technologies may increasingly compete with SDGEs traditional transmission and distribution infrastructure in delivering electricity to consumers. Natural Gas Utility Operations We describe SDGEs natural gas utility operations below in Sempra Californias Natural Gas Utility Operations. SoCalGas SoCalGas is a regulated public utility that owns and operates a natural gas distribution, transmission and storage system that delivers natural gas to a population of, at December 31, 2022, approximately 21.1 million, covering a 24,000 square mile service territory that encompasses Southern California and portions of central California (excluding San Diego County, the City of Long Beach and the desert area of San Bernardino County). 2022 Form 10-K | 16 Table of Contents SoCalGas assets at December 31, 2022 covered the following territory: Natural Gas Utility Operations We describe SoCalGas natural gas utility operations below in Sempra Californias Natural Gas Utility Operations. Sempra Californias Natural Gas Utility Operations Natural Gas Procurement and Transportation At December 31, 2022, SoCalGas natural gas facilities included 3,046 miles of transmission and storage pipelines, 52,020 miles of distribution pipelines, 48,918 miles of service pipelines and nine transmission compressor stations, and SDGEs natural gas facilities consisted of 168 miles of transmission pipelines, 9,112 miles of distribution pipelines, 6,718 miles of service pipelines and one compressor station. SoCalGas and SDGEs gas transmission pipelines interconnect with four major interstate pipeline systems: El Paso Natural Gas, Transwestern Pipeline, Kern River Pipeline Company, and Mojave Pipeline Company, allowing customers to bring gas supplies into the SoCalGas gas transmission pipeline system from the various out-of-state gas producing basins. Additionally, an interconnection with PGEs intrastate gas transmission pipeline system allows gas to flow into SoCalGas gas transmission pipeline system. SoCalGas gas transmission pipeline system also has an interconnect with a Mexican gas pipeline company at Otay Mesa on the California/Mexico border that allows gas to not only flow south from the gas producing basins in the southwestern U.S., but to also flow north into SoCalGas gas transmission pipeline system from LNG-sourced supplies in Mexico. There are also several in-state gas interconnections allowing for delivery of California-produced gas, including a number of direct connections from renewable natural gas producers. SoCalGas purchases natural gas under short-term and long-term contracts and on the spot market for SDGEs and

SoCalGas core customers. SoCalGas purchases natural gas from various sources, including from Canada, the U.S. Rockies and the southwestern regions of the U.S. Purchases of natural gas are primarily priced based on published monthly bid week indices, 2022 Form 10-K | 17 Table of Contents which can be subject to volatility. The cost of purchases of natural gas for SDGEs and SoCalGas core customers is billed to those customers without markup. To support the delivery of natural gas supplies to its distribution system and to meet the needs of customers, SoCalGas has firm and variable interstate pipeline capacity contracts that require the payment of fixed and variable tariffed and negotiated reservation charges to reserve firm transportation rights. Energy companies, primarily El Paso Natural Gas Company, Transwestern Pipeline Company and Kern River Gas Transmission Company, provide transportation services into SoCalGas intrastate transmission system for supplies purchased by SoCalGas. Natural Gas Storage SoCalGas owns four natural gas storage facilities with a combined working gas capacity of 137 Bcf and 126 injection, withdrawal and observation wells that provide natural gas storage service. SoCalGas and SDGEs core customers, along with certain third-party market participants, are allocated a portion of SoCalGas storage capacity. SoCalGas uses the remaining storage capacity for load balancing services for all customers. Natural gas withdrawn from storage is important to help maintain service reliability during peak demand periods, including consumer heating needs in the winter, as well as peak electric generation needs in the summer. The Aliso Canyon natural gas storage facility has a storage capacity of 86 Bcf and, subject to the CPUC limitations described below, represents 63% of SoCalGas natural gas storage capacity. SoCalGas discovered a natural gas leak at one of its wells at the Aliso Canyon natural gas storage facility in October 2015 and permanently sealed the well in February 2016. SoCalGas was subsequently authorized to make limited withdrawals and injections of natural gas at the Aliso Canyon natural gas storage facility and, on an interim basis, has been directed by the CPUC to maintain up to 41.16 Bcf of working gas at the facility to help achieve reliability for the region as determined by the CPUC. To help maintain system reliability, the CPUC issued a protocol authorizing withdrawals of natural gas from the facility if available gas supply reaches defined thresholds for SoCalGas system, or public health and safety is at risk, as determined by the protocol. We discuss the Leak in Note 16 of the Notes to Consolidated Financial Statements, in Part I Item 1A. Risk Factors and in Part II Item 7. MDA Capital Resources and Liquidity SoCalGas. Customers and Demand SoCalGas and SDGE sell, distribute and transport natural gas. SoCalGas purchases and stores natural gas for its core customers in its territory and SDGEs territory on a combined portfolio basis. SoCalGas also offers natural gas transportation and storage services for others. ##TABLE_START SEMPRA CALIFORNIA NATURAL GAS CUSTOMER METERS AND VOLUMES Customer meter count Volumes (Bcf) (1) December 31, Years ended December 31, 2022 2022 2021 2020 SDGE: Residential 878,220 Commercial 29,180 Electric generation and transportation 2,540 Natural gas sales 45 46 43 Transportation 39 38 40 Total 909,940 84 84 83 SoCalGas: Residential 5,857,280 Commercial 248,800 Industrial 24,390

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Electric generation and wholesale 40 Natural gas sales 304 314 312 Transportation 586 568 572 Total 6,130,510 890 882 884 ##TABLE_END(1) Includes intercompany sales. For regulatory purposes, end-use customers are classified as either core or noncore customers. Core customers are primarily residential and small commercial and industrial customers. 2022 Form 10-K | 18 Table of Contents Most core customers purchase natural gas directly from SoCalGas or SDGE. While core customers are permitted to purchase their natural gas supplies from producers, marketers or brokers, SoCalGas and SDGE are obligated to maintain adequate delivery capacity to serve the requirements of all their core customers. Noncore customers at SoCalGas consist primarily of electric generation, wholesale, and large commercial and industrial customers. A portion of SoCalGas noncore customers are non-end-users, which include wholesale customers consisting primarily of other utilities, including SDGE, or municipally owned natural gas distribution systems. Noncore customers at SDGE consist primarily of electric generation and large commercial customers. Noncore customers are responsible for procuring their natural gas requirements, as the regulatory framework does not allow SoCalGas and SDGE to recover the cost of natural gas procured and delivered to noncore customers. Natural gas demand largely depends on the health and expansion of the Southern California economy, prices of alternative energy products, consumer preference, environmental regulations, legislation, Californias energy policy supporting increased electrification and renewable power generation, and the effectiveness of energy efficiency programs. Other external factors such as weather, the price of, demand for, and supply sources of electricity, the use of and further development of renewable energy resources and energy storage, development of or requirements for new natural gas supply sources, demand for natural gas outside California, storage levels, transport capacity and availability of supply into California and general economic conditions can also result in significant shifts in the market price of natural gas, which may in turn impact demand. One of the larger sources for natural gas demand is electric generation. Natural gas-fired electric generation within Southern California (and demand for natural gas supplied to such plants) competes with electric power generated throughout the western U.S. Natural gas transported for electric generating plant customers may be affected by the overall demand for electricity, growth in self-generation from rooftop solar, the addition of more efficient gas technologies, new energy efficiency initiatives, and the degree to which regulatory changes in electric transmission infrastructure investment divert electric generation from SoCalGas and SDGEs service areas. The demand for natural gas may also fluctuate due to volatility in the demand for electricity due to seasonality, weather conditions and other impacts, and the availability of competing supplies of electricity, such as hydroelectric generation and other renewable energy sources. Given the significant quantity of natural gas-fired generation, we believe natural gas is a dispatchable fuel that can continue to help provide electric reliability in our California service territories. The natural gas distribution business is subject to seasonality, and cash provided by operating activities generally is greater during and immediately following the winter heating months. As is prevalent in the industry, but subject to current regulatory limitations, SoCalGas typically injects natural gas into storage during the months of April through October, and usually withdraws natural gas from storage during the months of November through March. Sempra Texas Utilities Sempra Texas Utilities is comprised of our equity method investments in Oncor Holdings and Sharyland Holdings. Oncor Holdings is an indirect, wholly owned entity of Sempra that owns an 80.25% interest in Oncor. TTI owns the remaining 19.75% interest in Oncor. Sempra owns an indirect, 50% interest in Sharyland Holdings, which owns a 100% interest in Sharyland Utilities. 2022 Form 10-K | 19 Table of Contents Sempra Texas Utilities assets at December 31, 2022 covered the following territory: Oncor Oncor is a regulated electricity transmission and distribution utility that operates in the north-central, eastern, western and panhandle regions of Texas. Oncor delivers electricity to end-use consumers through its electrical systems, and also provides transmission grid connections to merchant generation facilities and interconnections to other transmission grids in Texas. Oncors transmission and distribution assets are located in over 120 counties and more than 400 incorporated municipalities, including the cities of Dallas and Fort Worth and surrounding suburbs, as well as Waco, Wichita Falls, Odessa, Midland, Tyler, Temple, Killeen and Round Rock, among others. Most of Oncors power lines have been constructed over lands of others pursuant to easements or along public highways, streets and rights-of-way pursuant to permits, public utility easements, franchise or other agreements or as otherwise permitted by law. At December 31, 2022, Oncor had 4,561 employees, including 764 employees covered under a collective bargaining agreement. Certain ring-fencing measures, governance mechanisms and commitments, which we describe in Part I Item 1A. Risk Factors, are in effect and are intended to enhance Oncor Holdings and Oncors separateness from their owners and to mitigate the risk that these entities would be negatively impacted by the bankruptcy of, or other adverse financial developments affecting, their owners. Sempra does not control Oncor Holdings or Oncor, and the ring-fencing measures, governance mechanisms and commitments limit our ability to direct the management, policies and operations of Oncor Holdings and Oncor, including the deployment or disposition of their assets, declarations of dividends, strategic planning and other important corporate issues and actions, including limited representation on the Oncor Holdings and Oncor boards of directors. Because Oncor Holdings and Oncor are managed independently (i.e., ring-fenced), we account for our 100% ownership interest in Oncor Holdings as an equity method investment. Electricity Transmission. Oncors electricity transmission business is responsible for the safe and reliable operations of its transmission network and substations. These responsibilities consist of the construction, maintenance and security of transmission 2022 Form 10-K | 20 Table of Contents facilities and substations and the monitoring, controlling and dispatching of high-voltage electricity over its transmission facilities in coordination with ERCOT, which we discuss below in Regulation Utility Regulation ERCOT Market. At December 31, 2022, Oncors transmission system included approximately 18,268 circuit miles of transmission lines, a total of 1,207 transmission and distribution substations, and interconnection to 146 third-party generation facilities totaling 48,430 MW. Transmission revenues are provided under tariffs approved by either the PUCT or, to a small degree related to limited interconnection to other markets, the FERC. Network transmission revenues compensate Oncor for delivery of electricity over transmission facilities operating at 60 kV and above. Other services offered by Oncor through its transmission business include system impact studies, facilities studies, transformation service and maintenance of transformer equipment, substations and transmission lines owned by other parties. Electricity Distribution. Oncors electricity distribution business is responsible for the overall safe and reliable operation of distribution facilities, including electricity delivery, power quality, security and system reliability. These responsibilities consist of the ownership, management, construction, maintenance and operation of the electricity distribution system within its certificated service area. Oncors distribution system receives electricity from the transmission system through substations and distributes electricity to end-users and wholesale customers through 3,681 distribution feeders. Oncors distribution system included nearly 3.9 million points of delivery at December 31, 2022 and consisted of 123,500 miles of overhead and underground lines. Distribution revenues from residential and small business users are based on actual monthly consumption (kWh) and distribution revenues from large commercial and industrial users are based on, depending on size and annual load factor, either actual monthly demand (kW) or the greater of actual monthly demand (kW) or 80% of peak monthly demand during the prior eleven months. Customers and Demand. Oncor operates the largest transmission and distribution system in Texas based on the number of end-use customers and miles of transmission and distribution lines, delivering electricity to nearly 3.9 million homes and businesses, operating more than 141,000 miles of transmission and distribution lines as of December 31, 2022 in a territory with an estimated population of approximately 13 million. The consumers of the electricity Oncor delivers (other than ultimate end-use customers served by an electric cooperative or a municipally owned utility) are free to choose their electricity supplier from retail electric providers who compete for their business. Oncor is not a seller of electricity, nor does it purchase electricity for resale. Rather, Oncor provides transmission services to its electricity distribution business as well as non-affiliated electricity distribution companies, cooperatives and municipally owned utilities. Oncor also provides distribution services, consisting of retail delivery services to retail electric providers that sell electricity to end-use customers, as well as wholesale delivery services to cooperatives and municipally owned utilities. At December 31, 2022, Oncors distribution business customers primarily consisted of over 100 retail electric providers that sell the electricity it distributes to consumers in its certificated service areas. Oncors revenues and results of operations are subject to seasonality, weather conditions and other electricity usage drivers, with revenues being highest in the summer. Competition. Oncor operates in certificated areas designated by the PUCT. The majority of Oncors service territory is single certificated, with Oncor as the only certificated electric transmission and distribution provider. However, in multi-certificated areas of Texas, Oncor competes with certain other utilities and rural electric cooperatives for the right to serve end-use customers. In addition, the electric industry is undergoing rapid technological change, and third-party distributed energy resources and other technologies may increasingly compete with Oncors traditional transmission and distribution infrastructure in delivering electricity to consumers. Sharyland Utilities Sharyland Utilities is a regulated electric transmission utility that owns and operates, at December 31, 2022, approximately 64 miles of electric transmission lines in south Texas, including a direct current line connecting Mexico and assets in McAllen, Texas. Sharyland Utilities is responsible for providing safe, reliable and efficient transmission and substation services and investing to support infrastructure needs in its service territory, which we discuss below in Regulation Utility Regulation ERCOT Market. Transmission revenues are provided under tariffs approved by the PUCT. Sempra Infrastructure Our Sempra Infrastructure segment includes the operating companies of our subsidiary, SI Partners, as well as a holding company and certain services companies. SI Partners is included within our Sempra Infrastructure reportable segment, but is not the same in its entirety as the reportable segment. Sempra Infrastructure develops, builds, operates and invests in energy infrastructure to help enable the energy transition in North American markets and globally. 2022 Form 10-K | 21 Table of Contents Sempra Infrastructure owned a 70% interest in SI Partners at December 31, 2022, following its sale of a 20% NCI in SI Partners to KKR in October 2021 and sale of a 10% NCI in SI Partners to ADIA in June 2022. SI Partners has two authorized classes of limited partnership interests designated as Class A Units (which are common voting units) and Sole Risk Interests (which are only owned by Sempra, are non-voting and are not considered in the calculation of each limited partners respective ownership interests, subject to certain restrictions). We discuss KKRs and ADIAs purchases of NCI in SI Partners, as well as SI Partners limited partnership agreement that governs the partners respective rights and obligations in respect of their ownership interests in SI Partners in Note 1 of the Notes to Consolidated Financial Statements. SI Partners held a 100% ownership interest in Sempra LNG Holding, LP and a 99.9% ownership interest in IEnova at December 31, 2022, which consolidates Sempras ownership and management of its non-utility, energy infrastructure assets in North America under a single platform. These assets include LNG and natural gas infrastructure in the U.S. and Mexico and renewable energy, LPG and refined products infrastructure in Mexico, which are managed through three business lines: LNG and Net-Zero Solutions, Energy Networks and Clean Power. At December 31, 2022, Sempra Infrastructure owned or held interests in the following assets: LNG and Net-Zero Solutions Sempra Infrastructures LNG and Net-Zero Solutions business line is comprised of a natural gas liquefaction portfolio in operation, construction or development, and is focused on energy diversification and the clean energy transition in markets that our customers serve. Cameron LNG Phase 1 Facility. SI Partners owns 50.2% of Cameron LNG JV, while an affiliate of TotalEnergies SE, an affiliate of Mitsui

Co., Ltd., and Japan LNG Investment, LLC (a company jointly owned by Mitsubishi Corporation and Nippon Yusen Kabushiki Kaisha) each own 16.6% of Cameron LNG JV. We account for our ownership interest in Cameron LNG JV under the equity method. No single owner controls or can unilaterally direct significant activities of Cameron LNG JV. Cameron LNG JV owns and operates the Cameron LNG Phase 1 facility, a natural gas liquefaction, export, regasification and import facility with three natural gas pre-treatment, processing and liquefaction trains. The Cameron LNG Phase 1 facility is located in Hackberry, Louisiana, along the Calcasieu Ship Channel, which handles significant industrial shipping, including large 2022 Form 10-K | 22 Table of Contents oil and LNG tankers, and is well positioned to supply the Atlantic and Pacific markets. The three liquefaction trains have a combined nameplate capacity of 13.9 Mtpa of LNG with an export capacity of 12 Mtpa of LNG, or approximately 1.7 Bcf of natural gas per day. The Cameron LNG Phase 1 facility has 20-year liquefaction and regasification tolling capacity agreements in place with affiliates of TotalEnergies SE, Mitsubishi Corporation and Mitsui Co., Ltd., which collectively subscribe for the full nameplate capacity of the three trains at the facility. ECA Regas Facility. Sempra Infrastructure owns and operates the ECA Regas Facility in Baja California, Mexico, which is capable of processing one Bcf of natural gas per day and has a storage capacity of 320,000 cubic meters in two tanks of 160,000 cubic meters each. The ECA Regas Facility generates revenues from firm storage service fees under firm storage service agreements and nitrogen injection service agreements with Shell Mexico and Gazprom that expire in 2028, which permit them to collectively use 50% of the terminals capacity, with the remaining 50% of the capacity available for Sempra Infrastructures use. The land on which the ECA Regas Facility and the ECA LNG liquefaction projects under construction and in development are expected to be situated, as well as land adjacent to those properties, are the subject of litigation. We discuss the ECA Regas Facility arbitration and land litigation in Note 16 of the Notes to Consolidated Financial Statements and Part I Item 1A. Risk Factors. Sempra Infrastructure uses its 50% capacity at the ECA Regas Facility to satisfy its obligation under an LNG SPA with Tangguh PSC through 2029, which we discuss below, and ECA LNG Phase 1 will be the sole user of this capacity thereafter. Asset and Supply Optimization. Sempra Infrastructure has an LNG SPA through 2029 with Tangguh PSC for the supply of the equivalent of 500 MMcf of natural gas per day at a price based on the SoCal Border index for natural gas. The LNG SPA allows Tangguh PSC to divert certain LNG volumes to other global markets in exchange for payments of diversion fees. Sempra Infrastructure may also enter into short-term supply agreements to purchase LNG to be received, stored and regasified at the ECA Regas Facility for sale to other parties. Sempra Infrastructure uses the natural gas produced from this LNG to supply a contract for the sale of natural gas to the CFE at prices that are based on the SoCal Border index. If LNG volumes received from Tangguh PSC are not sufficient to satisfy the commitment to the CFE, Sempra Infrastructure may purchase natural gas in the market to satisfy such commitment. Sempra Infrastructure purchases, transports and sells natural gas, and has customers in both the U.S. and Mexico, including the CFE. Sempra Infrastructure may also purchase natural gas from other Sempra affiliates. Natural gas purchases and transportation arrangements are substantially backed by long-term, U.S. dollar-based contracts for the sale of natural gas to third parties (both U.S. sourced and derived from imported LNG), LNG offtake and natural gas storage and pipeline capacity. ECA LNG Phase 1 Project. SI Partners owns an 83.4% interest in ECA LNG Phase 1, and an affiliate of TotalEnergies SE owns the remaining 16.6% interest. ECA LNG Phase 1 is constructing a one-train natural gas liquefaction facility at the site of Sempra Infrastructures existing ECA Regas Facility with a nameplate capacity of 3.25 Mtpa and an initial offtake capacity of 2.5 Mtpa. We expect the ECA LNG Phase 1 project to commence commercial operations in the summer of 2025. ECA LNG Phase 1 has definitive 20-year SPAs with an affiliate of TotalEnergies SE for approximately 1.7 Mtpa of LNG and Mitsui Co., Ltd. for approximately 0.8 Mtpa of LNG. The construction of the ECA LNG Phase 1 project is subject to numerous risks and uncertainties. For a discussion of these risks and uncertainties, see Part I Item 1A. Risk Factors and Part II Item 7. MDA Capital Resources and Liquidity Sempra Infrastructure. Additional Potential LNG and Net-Zero Solutions Projects. Sempra Infrastructure is evaluating the following development opportunities: Cameron LNG Phase 2 project, an expansion of the Cameron LNG Phase 1 facility ECA LNG Phase 2 project, a large-scale natural gas liquefaction project to be located at the site of Sempra Infrastructures existing ECA Regas Facility in Baja California, Mexico PA LNG projects, a large-scale natural gas liquefaction project, to be developed in two phases, and associated infrastructure on a greenfield site in the vicinity of Port Arthur, Texas located along the Sabine-Neches waterway Vista Pacifico LNG project, a mid-scale natural gas liquefaction project and associated infrastructure in the vicinity of Topolobampo in Sinaloa, Mexico Hackberry Carbon Sequestration project, a carbon capture and sequestration project that is intended to reduce emissions at the Cameron LNG Phase 1 facility and proposed Cameron LNG Phase 2 project 2022 Form 10-K | 23 Table of Contents No final investment decision has been reached for any of these potential projects. The development of these projects is subject to numerous risks and uncertainties. For a discussion of these proposed projects and their risks, see Part I Item 1A. Risk Factors and Part II Item 7. MDA Capital Resources and Liquidity Sempra Infrastructure. Demand and Competition. North America benefits from numerous competitive advantages as a potential supplier of LNG to world markets, including the following: high levels of developed and undeveloped natural gas resources, including unconventional natural gas and tight oil relative to domestic consumption levels flexible and elastic markets in gas and oil drilling and production resulting in efficient unit costs of gas production availability of extensive pre-existing natural gas pipeline transmission systems and natural gas storage capacity with proximity to production locations Brownfield liquefaction projects also benefit from the particular competitive advantage of the proximity of pre-existing infrastructure, such as LNG tankage and berths. Global LNG competition may limit North American LNG exports, as international liquefaction projects attempt to match North American LNG production costs and customer contractual rights such as volume and destination flexibility. It is expected that North American LNG exports will increase competition for current and future global natural gas demand, and thereby facilitate additional growth of a global commodity market for natural gas and LNG. Cameron LNG JV co-owners and customers compete globally to market and sell LNG to end users, including gas and electric utilities located in LNG-importing countries around the world. By providing liquefaction services, Cameron LNG JV and future LNG export development projects compete indirectly with liquefaction projects currently operating and those under development in the global LNG market. In addition to the U.S., these competitors are located in the Middle East, Southeast Asia, Africa, South America, Australia and Europe. The competitive environment shifted in favor of North American LNG development projects in 2022 in the wake of the war in Ukraine and the resulting focus by European markets on alternative supplies. This shift in demand underscores the attractiveness of long-term contracts from North American LNG projects. The LNG regasification business is impacted by global LNG market prices. High LNG prices in markets outside the market in which Sempra Infrastructures ECA Regas Facility operates have resulted and could continue to result in lower-than-expected deliveries of LNG cargoes to the ECA Regas Facility, which could increase costs if Sempra Infrastructure is instead required to obtain LNG in the open market at prevailing prices. Any inability to obtain expected LNG cargoes could also impact Sempra Infrastructures ability to maintain the minimum level of LNG required to keep the ECA Regas Facility in operation at the proper temperature. Prices in international LNG markets through which Sempra Infrastructure must purchase natural gas to meet its contractual obligations to deliver natural gas to customers may also affect how Sempra Infrastructure optimizes its assets and supply, which could have an adverse impact on its earnings. Energy Networks Sempra Infrastructures Energy Networks business line is comprised of a natural gas transportation and distribution network. Cross-Border Interconnections and In-Country Pipelines. Sempra Infrastructure develops, builds, operates and invests in systems for the receipt, transportation, compression and delivery of natural gas and ethane. At December 31, 2022, these systems consisted of 1,850 miles of natural gas transmission pipelines plus 124 miles under construction, 16 natural gas compression stations plus one under construction, and 139 miles of ethane pipelines in Mexico. The design capacity of these pipeline assets is over 16,400 MMcf per day of natural gas, 204 MMcf per day of ethane gas and 106,000 barrels per day of ethane liquid. Capacity on Sempra Infrastructures pipelines and related assets is substantially contracted under long-term, U.S. dollar-based agreements with major industry participants such as the CFE, Centro Nacional de Control de Gas, PEMEX, Gazprom and other similar counterparties. Some of these pipeline assets are affected by disputes related to the property on which the pipelines are located, which we discuss in Note 16 of the Notes to Consolidated Financial Statements and Part I Item 1A. Risk Factors. Sempra Infrastructure owns a 40-mile natural gas pipeline in south Louisiana, the Cameron

Interstate Pipeline, which links the Cameron LNG Phase 1 facility in Cameron Parish in Louisiana, to five interstate pipelines that offer access to major feed gas supply basins in Texas and the northeast, midcontinent and southeast regions of the U.S. The majority of transportation capacity on the Cameron Interstate Pipeline is under long-term transportation service agreements with shippers for delivery to the Cameron LNG Phase 1 facility. Natural Gas Distribution. Sempra Infrastructures natural gas distribution regulated utility, Ecogas, operates in three separate distribution zones in Mexicali, Chihuahua and La Laguna-Durango, Mexico. At December 31, 2022, Ecogas had approximately 2,952 miles of distribution pipeline, and approximately 150,000 customer meters serving more than 525,000 residential, 2022 Form 10-K | 24 Table of Contents commercial and industrial consumers with sales volume of approximately 10 MMcf per day in 2022. Ecogas relies on supply and transportation services from Sempra Infrastructure, SoCalGas and PEMEX for the natural gas it distributes to its customers. LPG Storage and Associated Systems. Sempra Infrastructure owns and operates the TDF, S. de R. L. de C. V. (TDF) pipeline system and the Guadalajara LPG terminal. At December 31, 2022, the TDF pipeline system consisted of approximately 118 miles of 12-inch diameter LPG pipeline with a design capacity of 34,000 barrels per day and associated storage and dispatch facilities. The TDF pipeline system runs from PEMEXs Burgos facility in the Mexican State of Tamaulipas, Mexico to Sempra Infrastructures delivery facility near the city of Monterrey, Mexico and is fully contracted to PEMEX on a firm basis through 2027. Sempra Infrastructures Guadalajara LPG terminal is an 80,000-barrel LPG storage facility near Guadalajara, Mexico, with associated loading and dispatch facilities, and serves the LPG needs of Guadalajara. The Guadalajara LPG terminal is fully contracted to PEMEX on a firm basis through 2028. Both contracts are U.S. dollar-denominated or referenced and are periodically adjusted for inflation. Refined Products Storage. Sempra Infrastructures refined products storage business develops, constructs and operates systems for the receipt, storage and delivery of refined products, principally gasoline, diesel and jet fuel, throughout the Mexican states of Baja California, Colima, Puebla, Sinaloa, Veracruz and Valle de Mxico for private companies, with a combined storage capacity of 4.6 million barrels fully operating or under construction/commissioning as of December 31, 2022. The inland terminal in the vicinity of Puebla reached commercial operations in October 2022. Construction of the Topolobampo marine terminal was substantially completed in May 2022, at which time commissioning activities commenced. Subject to the receipt of pending permits, we expect the Topolobampo terminal will commence commercial operations in the first half of 2023. Our customer contracts for our refined products storage business are structured as long-term, U.S. dollar-denominated, firm capacity storage agreements with counterparties including Chevron Corporation, Marathon Petroleum Corporation and Valero Energy Corporation. The contracted rate under these contracts is independent from each terminals regulated rate as determined by the CRE. Demand and Competition. Ecogas faces competition from other distributors of natural gas in each of its three distribution zones in Mexicali, Chihuahua and La Laguna-Durango, Mexico as other distributors of natural gas build or consider building natural gas distribution systems. Sempra Infrastructures pipeline and storage facilities businesses compete with other regulated and unregulated pipeline and storage facilities. They compete primarily on the basis of price (in terms of storage and transportation fees), available capacity and interconnections to downstream markets. The overall demand for natural gas distribution services increases during the winter months, while the overall demand for power increases during the summer months. Clean Power Sempra Infrastructures Clean Power business line consists of a renewable energy infrastructure portfolio and a natural gas-fired power plant in Mexico. Renewable Power Generation. Sempra Infrastructure develops, builds, invests in and operates renewable energy generation facilities that have long-term PPAs to sell the electricity they generate to their customers, which are generally load serving entities, as well as industrial and other customers. Load serving entities sell electric service to their end-users and wholesale customers upon receipt of power delivery from these energy generation facilities, while industrial and other customers consume the electricity to run their facilities. At December 31, 2022, Sempra Infrastructure had a fully contracted, total nameplate capacity of 1,044 MW related to its fully operating wind and solar power generation facilities. Some of these facilities are impacted by regulatory actions by the Mexican government and related litigation, which we discuss in Note 16 of the Notes to Consolidated Financial Statements, Part I Item 1A. Risk Factors and Part II Item 7. MDA Capital Resources and Liquidity Sempra Infrastructure. 2022 Form 10-K | 25 Table of Contents ##TABLE_START SEMPRA INFRASTRUCTURE RENEWABLE POWER GENERATION Location Contract expiration date Nameplate capacity (MW) Wind power generation facilities: ESJ first phase Tecate, Baja California 2035 155 ESJ second phase (1) Tecate, Baja California 2042 108 Ventika Nuevo Len, Mexico 2036 252 Solar power generation facilities: Border Solar Ciudad Juarez, Chihuahua 2032 and 2037 150 Don Diego Solar Benjamin Hill, Sonora 2034 and 2037 125 Pima Solar Caborca, Sonora 2038 110 Rumorosa Solar Tecate, Baja California 2034 44 Tepezal Solar Aguascalientes 2034 100 Total 1,044 ##TABLE_END(1) Commenced commercial operations in January 2022. Natural Gas-Fired Generation. Sempra Infrastructure owns and operates the TdM power plant in the vicinity of Mexicali, Baja California, adjacent to the Mexico-U.S. border. TdM is a 625-MW natural gas-fired, combined-cycle power plant that is connected to our Gasoducto Rosarito pipeline system, which enables it to receive regasified LNG from the ECA Regas Facility as well as continental gas supplied from the U.S. on the North Baja pipeline. TdM generates revenue from selling electricity and resource adequacy to the California ISO and to governmental, public utility and wholesale power marketing entities. Demand and Competition. Sempra Infrastructure competes with Mexican and foreign companies for new energy infrastructure projects in Mexico. Some of its competitors (including public or state-operated companies and their affiliates) may have better access to capital and greater financial and other resources, which could give them a competitive advantage for such projects. Generation from Sempra Infrastructures renewable energy assets is susceptible to fluctuations in naturally occurring conditions such as wind, inclement weather and hours of sunlight. Because Sempra Infrastructure sells power that it generates at its ESJ wind power generation facility into California, Sempra Infrastructures future performance and the demand for renewable energy may be impacted by U.S. state mandated requirements to deliver a portion of total energy load from renewable energy sources. The rules governing these requirements in California are generally known as the RPS Program. In California, certification of a generation project by the CEC as an ERR allows the purchase of output from such generation facility to be counted towards fulfillment of the RPS Program requirements, if such purchase meets the provisions of SB X1-2, the California Renewable Energy Resources Act. The RPS Program may affect the demand for output from renewable energy projects developed by Sempra Infrastructure, particularly the demand from Californias utilities. The first phase of ESJ, a wind power generation facility that delivers energy into California, has been certified by the CEC and is in compliance with the RPS Program as of December 31, 2022. Sempra Infrastructure is pursuing ERR certification for the second phase of ESJ. TdM competes daily with other generating plants that supply power into the California electricity market. Sempra Infrastructure manages commodity price risk at TdM by using a mix of day ahead sales of energy, energy spreads hedging, ancillary services, and short-term to medium-term capacity sales. Discontinued Operations We completed the sales of our equity interests in our Peruvian businesses in April 2020 and our Chilean businesses in June 2020. These South American businesses included our former 100% interest in Chilquinta Energa (an electric distribution utility in Chile), our former 83.6% interest in Luz del Sur (an electric distribution utility in Peru) and our former interests in two energy-services companies, Tecnored and Tecsur, which provide electric construction and infrastructure services to Chilquinta Energa and Luz del Sur, respectively, as well as third parties. These businesses and certain activities associated with these businesses are presented as discontinued operations in this report. We provide further information about discontinued operations in Note 5 of the Notes to Consolidated Financial Statements. REGULATION We discuss the material effects of compliance with all government regulations, including environmental regulations, on our capital expenditures, earnings and competitive position in Part II Item 7. MDA and Note 16 of the Notes to Consolidated Financial Statements. 2022 Form 10-K | 26 Table of Contents Utility Regulation California SDGE and SoCalGas are principally regulated at the state level by the CPUC, CEC and CARB. The CPUC: consists of five commissioners appointed by the Governor of California for staggered, six-year terms; regulates, among other things, SDGEs and SoCalGas customer rates and conditions of service, sales of securities, rates of return, capital structure, rates of depreciation, and long-term resource procurement, except as described below in U.S. Federal; has jurisdiction over the proposed construction of major new electric generation, transmission and distribution, and natural gas storage, transmission and distribution facilities in California; conducts reviews and audits of utility performance and compliance with regulatory guidelines and conducts investigations related to various matters, such as safety, reliability and planning, deregulation, competition and the environment; and regulates the interactions and transactions of SDGE and SoCalGas with Sempra and its other affiliates. The CPUC also oversees and regulates other energy-related products and services, including solar and wind energy, bioenergy, alternative energy storage and other forms of renewable energy. In addition, the CPUCs safety and enforcement role includes inspections, investigations and penalty and citation processes for safety and other violations. The CEC publishes electric demand forecasts for the state and specific service territories. Based on these forecasts, the CEC: determines the need for additional energy sources and conservation programs; sponsors alternative-energy research and development projects; promotes energy conservation programs to reduce demand for natural gas and electricity within California; maintains a statewide plan of action in case of energy shortages; and certifies power-plant sites and related facilities within California. The CEC conducts a 20-year forecast of available supplies and prices for every market sector that consumes natural gas in California. This forecast includes resource evaluation, pipeline capacity needs, natural gas demand and wellhead prices, and transportation and distribution costs. This analysis is one of many resource materials used to support SDGEs and SoCalGas long-term investment decisions. California requires certain electric retail sellers, including SDGE, to deliver a significant percentage of their retail energy sales from renewable energy sources. The rules governing this requirement, administered by the CPUC and the CEC, are generally known as the RPS Program. California has implemented a program whereby IOUs providing gas service in California will procure a portion of the natural gas they deliver from biomethane. The proportion of biomethane procured will be phased-in with a state-wide, short-term target in 2025 of 17.6 Bcf per year and a medium-term target in 2030 of 72.8 Bcf per year. SDGE and SoCalGas are allocated 6.77% and 49.26%, respectively, of the 2025 target, and 7.60% and 52.02%, respectively, of the 2030 target. The rules governing this program are administered by the CPUC under SB 1440. AB 32, the California Global Warming Solutions Act of 2006, assigns responsibility to CARB for monitoring and establishing policies for reducing GHG emissions. The law requires CARB to develop and adopt a comprehensive plan for achieving real, quantifiable and cost-effective GHG emissions reductions, including a statewide GHG emissions cap, mandatory reporting rules, and regulatory and market mechanisms to achieve reductions of GHG emissions. CARB is a department within the California Environmental Protection Agency, an organization that reports directly to the Governors Office. Sempra Infrastructure is also subject to the rules and regulations of CARB. The California Geologic Energy Management Division, the CPUC, and various other state and local agencies regulate the operation and maintenance of SoCalGas natural gas storage facilities. Texas Oncors and Sharyland Utilities rates are regulated at the state level by the PUCT and, in the case of Oncor, at the city level by certain cities. The PUCT has original jurisdiction over wholesale transmission rates and services and retail rates and services in unincorporated areas and in those municipalities that have ceded original jurisdiction to the PUCT, and has exclusive appellate jurisdiction to review the retail rate and service orders and ordinances of municipalities. Generally, the Texas PURA prohibits the collection of any rates or charges by a public utility (as defined by PURA) that do not have the prior approval of the appropriate regulatory authority (i.e., the PUCT or the municipality with original jurisdiction). 2022 Form 10-K | 27 Table of Contents At the state level, PURA requires utility owners or operators of electric transmission facilities to provide open-access wholesale transmission services to third parties at rates and terms that are nondiscriminatory and comparable to the rates and terms of the utilitys own use of its system. The PUCT has adopted rules implementing the state open-access requirements for all utilities that are subject to the PUCTs jurisdiction over electric transmission services, including Oncor. U.S. Federal SDGE and SoCalGas are also regulated at the federal level by the FERC, the EPA, the DOE and the DOT, and for SDGE the NRC. The FERC regulates SDGEs and SoCalGas interstate sale and transportation of natural gas. The FERC also regulates SDGEs transmission and wholesale sales of electricity in interstate commerce, transmission access, rates of return on transmission investment, rates of depreciation, electric rates involving sales for resale and the application of the uniform system of accounts. The U.S. Energy Policy Act governs procedures for requests for electric transmission service. The California IOUs electric transmission facilities are under the operational control of the California ISO. As member utilities, Oncor and Sharyland Utilities operate within the ERCOT market, which we discuss below. To a small degree related to limited interconnections to other markets, Oncors electric transmission revenues are provided under tariffs approved by the FERC. The NRC oversees the licensing, construction, operation and decommissioning of nuclear facilities in the U.S., including SONGS, in which SDGE owns a 20% interest and which was permanently retired in 2013. The NRC and various state regulations require extensive review of these facilities safety, radiological and environmental aspects. We provide further discussion of SONGS matters, including the closure and decommissioning of the facility, in Note 15 of the Notes to Consolidated Financial Statements. The EPA implements federal laws to protect human health and the environment, including federal laws on air quality, water quality, wastewater discharge, solid waste management, and hazardous waste disposal and remediation. The EPA also sets national environmental standards that state and tribal governments implement through their regulations. As a result, SDGE, SoCalGas, Oncor and Sharyland Utilities are subject to an interrelated framework of environmental laws and regulations. The DOT, through PHMSA, has established regulations regarding engineering standards and operating procedures, including procedures intended to manage cybersecurity risks, applicable to SDGEs and SoCalGas natural gas transmission and distribution pipelines, as well as natural gas storage facilities. The DOT has certified the CPUC to administer oversight and compliance with these regulations for the entities they regulate in California. ERCOT Market As member utilities, Oncor and Sharyland Utilities operate within the ERCOT market, which represents approximately 90% of the electricity consumption in Texas. ERCOT is the regional reliability coordinating organization for member electricity systems in Texas and the ISO of the interconnected transmission grid for those systems. ERCOT is subject to oversight by the PUCT and the Texas Legislature. ERCOT is responsible for ensuring reliability, adequacy and security of the electric systems, as well as nondiscriminatory access to transmission service by all wholesale market participants, in the ERCOT region. ERCOTs membership consists of corporate and associate members, including electric cooperatives, municipal power agencies, independent generators, independent power marketers, transmission service providers, distribution service providers, independent retail electric providers and consumers. The PUCT has primary jurisdiction over the ERCOT market to ensure the adequacy and reliability of power supply across Texas main interconnected electric transmission grid. Oncor and Sharyland Utilities, along with other owners of electric transmission and distribution facilities in Texas, participate with the ERCOT ISO and other member utilities in its operations. Each of these Texas utilities has planning, design, construction, operation, maintenance and security responsibility for the portion of the transmission grid and the load-serving substations it owns, primarily within its certificated distribution service area. Each participates with the ERCOT ISO and other ERCOT utilities in obtaining regulatory approvals and planning, designing, constructing and upgrading transmission lines in order to remove any existing constraints and interconnect energy generation on the ERCOT transmission grid. These transmission line projects are necessary to meet reliability needs, support energy production and increase bulk power transfer capability. Oncor and Sharyland Utilities are subject to reliability standards adopted and enforced by the Texas Reliability Entity, Inc., an independent organization that develops reliability standards for the ERCOT region and monitors and enforces compliance with the standards of the North American Electric Reliability Corporation, including critical infrastructure protection, and ERCOT protocols. 2022 Form 10-K | 28 Table of Contents Other U.S. State and Local Territories Regulation The South Coast Air Quality Management District is the air pollution control agency responsible for regulating stationary sources of air pollution in the South Coast Air Basin in Southern California. The districts territory covers all of Orange County and the urban portions of Los Angeles, San Bernardino and Riverside counties. SDGE has electric franchise agreements with the two counties and the 27 cities in its electric service territory, and natural gas franchise agreements with the one county and the 18 cities in its natural gas service territory. These franchise agreements allow SDGE to locate, operate and maintain facilities for the transmission and distribution of electricity or natural gas. Most of the franchise agreements have no expiration dates, while some have expiration dates that range from 2028 to 2041. In June 2021, the City of San Diego approved ordinances granting SDGE the electric and natural gas franchises for the City of San Diego. These franchise agreements provide SDGE the opportunity to serve the City of San Diego for the next 20 years, consisting of 10-year agreements that will automatically renew for an additional 10 years unless the City Council voids the automatic renewal with a supermajority vote. These franchise agreements went into effect in July 2021.

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SoCalGas has natural gas franchise agreements with the 12 counties and the 232 cities in its service territory. These franchise agreements allow SoCalGas to locate, operate and maintain facilities for the transmission and distribution of natural gas. Most of the franchise agreements have no expiration dates, while some have expiration dates that range from 2023 to 2069, including the Los Angeles County franchise, which is scheduled to expire in June 2023. Other U.S. Regulation The FERC regulates certain Sempra Infrastructure assets pursuant to the U.S. Federal Power Act and Natural Gas Act, which provide for FERC jurisdiction over, among other things, sales of wholesale power in interstate commerce, transportation of natural gas in interstate commerce, and siting and permitting of LNG facilities. The FERC may regulate rates and terms of service based on a cost-of-service approach or, in geographic and product markets determined by the FERC to be sufficiently competitive, rates may be market-based. FERC-regulated rates at Sempra Infrastructure are market-based for wholesale electricity sales, cost-based for the transportation of natural gas, and market-based for the purchase and sale of LNG and natural gas. Sempra Infrastructures investment in Cameron LNG JV is subject to regulations of the DOE regarding the export of LNG. Sempra Infrastructures other potential natural gas liquefaction projects would, if completed, be subject to similar regulations. SDGE, SoCalGas and businesses in which Sempra Infrastructure invests are subject to the DOT rules and regulations regarding pipeline safety. PHMSA, acting through the Office of Pipeline Safety, is responsible for administering the DOTs national regulatory program to help ensure the safe transportation of natural gas, petroleum and other hazardous materials by pipelines, including pipelines associated with natural gas storage, and develops regulations and other approaches to risk management to help ensure safety in design, construction, testing, operation, maintenance and emergency response of pipeline facilities. SDGE, SoCalGas and Sempra Infrastructure are also subject to regulation by the U.S. Commodity Futures Trading Commission. Foreign Regulation Operations and projects in our Sempra Infrastructure segment are subject to regulation by the CRE, ASEA, SENER, the Mexican Ministry of Environment and Natural Resources of Mexico (Secretara del Medio Ambiente y Recursos Naturales), and other labor and environmental agencies of city, state and federal governments in Mexico. New energy infrastructure projects may also require a favorable opinion from Comisin Federal de Competencia Econmica (Mexicos Competition Commission) in order to be constructed and operated. Licenses and Permits Our utilities in California and Texas obtain numerous permits, authorizations and licenses for, as applicable, the transmission and distribution of natural gas and electricity and the operation and construction of related assets, including electric generation and natural gas storage facilities, some of which may require periodic renewal. Sempra Infrastructure obtains numerous permits, authorizations and licenses for its electric and natural gas distribution, generation and transmission systems from the local governments where these services are provided. The permits for generation, transportation, storage and distribution operations at Sempra Infrastructure are generally for 30-year terms, with options for renewal under certain regulatory conditions. Sempra Infrastructure obtains licenses and permits for the construction, operation and expansion of LNG facilities and for the import and export of LNG and natural gas. Sempra Infrastructure also obtains licenses and permits for the construction and operation of facilities for the receipt, storage and delivery of refined products. 2022 Form 10-K | 29 Table of Contents Sempra Infrastructure obtains permits, authorizations and licenses for the construction and operation of natural gas storage facilities and pipelines, and in connection with participation in the wholesale electricity market. Most of the permits and licenses associated with Sempra Infrastructures construction and operations are for periods generally in alignment with the construction cycle or expected useful life of the asset and in many cases are greater than 20 years. RATEMAKING MECHANISMS Sempra California General Rate Case Proceedings A CPUC GRC proceeding is designed to set sufficient base rates to allow SDGE and SoCalGas to recover their reasonable forecasted operating costs and to provide the opportunity to realize their authorized rates of return on their investments. The proceeding generally establishes the test year revenue requirements, which authorizes how much SDGE and SoCalGas can collect from their customers, and provides for attrition, or annual increases in revenue requirements, for each year following the test year. We discuss the GRC in Note 4 of the Notes to Consolidated Financial Statements. Cost of Capital Proceedings A CPUC cost of capital proceeding every three years determines a utilitys authorized capital structure and authorized return on rate base, which is a weighted-average of the authorized returns on debt, preferred equity and common equity (referred to as return on equity or ROE), weighted on a basis consistent with the authorized capital structure. The authorized return on rate base approved by the CPUC is the rate that SDGE and SoCalGas use to establish customer rates to finance investments in CPUC-regulated electric distribution and generation, natural gas distribution, transmission and storage assets, as well as general plant and information technology systems investments to support operations. A cost of capital proceeding also addresses the CCM, which applies in the interim years between required cost of capital applications and considers changes in the cost of capital based on changes in interest rates based on the applicable utility bond index published by Moodys (the CCM benchmark rate) for each 12-month period ending September 30 (the measurement period). The index applicable to SDGE and SoCalGas is based on each utilitys credit rating. The CCM benchmark rate is the basis of comparison to determine if the CCM is triggered in each measurement period, which occurs if the change in the applicable Moodys utility bond index relative to the CCM benchmark rate is larger than plus or minus 1.000% at the end of the measurement period. The CCM, if triggered, would automatically update the authorized cost of debt based on actual costs and update the authorized ROE upward or downward by one-half of the difference between the CCM benchmark rate and the applicable Moodys utility bond index. Alternatively, each of SDGE and SoCalGas are permitted to file a cost of capital application in an interim year in which an extraordinary or catastrophic event materially impacts its cost of capital and affects utilities differently than the market as a whole to have its cost of capital determined in lieu of the CCM. We discuss the cost of capital and CCM in Note 4 of the Notes to Consolidated Financial Statements and in Part I Item 1A. Risk Factors. Transmission Rate Cases SDGE files separately with the FERC for its authorized ROE on FERC-regulated electric transmission operations and assets. The proceeding establishes a ROE and a formulaic rate whereby rates are determined using (i) a base period of historical costs and a forecast of capital investments, and (ii) a true-up period, similar to balancing account treatment, that is designed to provide earnings equal to SDGEs actual cost of service including its authorized return on investment. SDGE makes annual information filings with the FERC in December to update rates for the following calendar year. SDGE may also file for ROE incentives that might apply under FERC rules. SDGEs debt-to-equity ratio is set annually based on the actual ratio at the end of each year. Incentive Mechanisms The CPUC applies certain performance-based measures and incentive mechanisms to all California IOUs, under which SDGE and SoCalGas have earnings potential above the authorized CPUC base operating margin if they achieve or exceed specific performance and operating goals. Generally, for performance-based measures, if performance is above or below specific benchmarks, the utility is eligible for financial awards or subject to financial penalties. 2022 Form 10-K | 30 Table of Contents Other Cost-Based Recovery The CPUC, and the FERC as it relates to SDGE, authorize SDGE and SoCalGas to collect revenue requirements from customers for operating and capital-related costs (depreciation, taxes and return on rate base), including: costs to purchase natural gas and electricity; costs associated with administering public purpose, demand response, and customer energy efficiency programs; other programmatic activities, such as gas distribution, gas transmission, gas storage integrity management and wildfire mitigation; and costs associated with third-party liability insurance premiums. Authorized costs are recovered as the commodity or service is delivered. To the extent authorized amounts collected vary from actual costs, the differences are generally recovered or refunded in a subsequent period based on the nature of the balancing account mechanism. Generally, the revenue recognition criteria for balanced costs billed to customers are met when the costs are incurred. Because these costs are substantially recovered in rates through a balancing account mechanism, changes in these costs are reflected as changes in revenues. The CPUC and the FERC may impose various review procedures before authorizing recovery or refund of amounts accumulated for authorized programs, including limitations on the programs total cost, revenue requirement limits or reviews of costs for reasonableness. These procedures could result in delays or disallowances of recovery from ratepayers. Sempra Texas Utilities Rates and Cost Recovery Oncors and Sharyland Utilities rates are each regulated at the state level by the PUCT and, in the case of Oncor, at the city level by certain cities, and are subject to regulatory rate-setting processes and earnings oversight. This regulatory treatment does not provide assurance as to achievement of earnings levels or recovery of actual costs. Instead, their rates are based on an analysis of each utilitys costs and capital structure in a designated test year, as reviewed and approved in regulatory proceedings. Rate regulation is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital. However, there is no assurance that the PUCT will judge all of the Texas utilities costs to have been prudently incurred and therefore fully recoverable. The approved levels of recovery could be significantly less than requested levels. There can also be no assurance that the PUCT will approve other items proposed in any rate proceeding or that the regulatory process in which rates are determined will necessarily result in rates that produce full recovery of the Texas utilities actual post-test year costs and/or the return on invested capital allowed by the PUCT. PUCT rules allow Texas electric utilities providing wholesale or retail distribution service to file applications, under certain circumstances, once per year to recover distribution-related investments placed into service between base rate review proceedings. PUCT rules also allow the Texas utilities to update their transmission rates twice a year between base rate review proceedings to reflect changes in transmission-related invested capital. These applications for interim rate adjustments between base rate reviews, known as capital tracker provisions, are intended to encourage investment in the electric system to help ensure reliability and efficiency by helping to shorten the time period between a utilitys investment in transmission and distribution infrastructure and its ability to start recovering and earning a return on such investments. However, all investments included in a capital tracker are ultimately subject to prudence review by the PUCT in the next base rate review, after such assets are put into service. Capital Structure and Return on Equity Oncor currently has a PUCT-authorized ROE of 9.8% and an authorized regulatory capital structure of 57.5% debt to 42.5% equity. Oncor filed its base rate review request with the PUCT in May 2022. Resolution of the base rate review requires issuance of a final order by the PUCT, which Oncor expects to receive around the end of the first quarter of 2023. Once the final order is issued, the approved rates will be in effect until the next base rate review is finalized. In accordance with PUCT rules, Oncor must file a comprehensive base rate review within four years of the order setting rates in Oncors most recent comprehensive base rate proceeding, unless an extension is otherwise approved by the PUCT. However, the PUCT or any city retaining original jurisdiction over rates may direct Oncor to file a base rate review, or Oncor may voluntarily file a base rate review, any time prior to that filing deadline. Sharyland Utilities 2020 rate case became effective in July 2021 and remains effective until the next rate case is finalized, which we expect could be in late 2025. Sharyland Utilities PUCT-authorized ROE is 9.38% and its authorized regulatory capital structure is 60% debt to 40% equity. 2022 Form 10-K | 31 Table of Contents Sempra Infrastructure Ecogas revenues are derived from service and distribution fees charged to its customers in Mexican pesos. The price Ecogas pays to purchase natural gas, which is based on international price indices, is passed through directly to its customers. The service and distribution fees charged by Ecogas are regulated by the CRE, which performs a review of rates every five years and monitors prices charged to end-users. In the fourth quarter of 2020, Ecogas filed its rate case for 2021 through 2025 and is awaiting CRE approval. The tariffs operate under a

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return-on-asset-base model. In the annual tariff adjustment, rates are adjusted to account for inflation or fluctuations in exchange rates, and inflation indexing includes separate U.S. and Mexican cost components so that U.S. costs can be included in the final distribution rates. ENVIRONMENTAL MATTERS We discuss environmental issues affecting us in Note 16 of the Notes to Consolidated Financial Statements and Part I Item 1A. Risk Factors. You should read the following additional information in conjunction with those discussions. Hazardous Substances The CPUCs Hazardous Waste Collaborative mechanism allows Californias IOUs to recover hazardous waste cleanup costs for certain sites, including those related to certain Superfund sites. For sites that are covered by this mechanism, SDGE and SoCalGas are permitted to recover in rates 90% of hazardous waste cleanup costs and related third-party litigation costs, and 70% of related insurance-litigation expenses. In addition, SDGE and SoCalGas can retain a percentage of any recoveries from insurance carriers and other third parties to offset the cleanup and associated litigation costs not recovered in rates. We record estimated liabilities for environmental remediation when amounts are probable and estimable. In addition, we record amounts authorized to be recovered in rates under the Hazardous Waste Collaborative mechanism as regulatory assets. Air and Water Quality The natural gas and electric industries are subject to increasingly stringent air quality and GHG emissions standards, such as those established by CARB and the South Coast Air Quality Management District. SDGE and SoCalGas generally recover the costs to comply with these standards in rates. We discuss GHG emissions standards and credits further in Note 1 of the Notes to Consolidated Financial Statements. 2022 Form 10-K | 32 Table of Contents OTHER MATTERS Information About Our Executive Officers ##TABLE_START INFORMATION ABOUT EXECUTIVE OFFICERS AT SEMPRA Name Age (1) Positions held over last five years Time in position Jeffrey W. Martin 61 Chairman December 2018 to present Chief Executive Officer May 2018 to present President March 2020 to present Executive Vice President and Chief Financial Officer January 2017 to May 2018 Kevin C. Sagara 61 Executive Vice President and Group President June 2020 to present Chief Executive Officer, SDGE September 2018 to June 2020 President, Sempra Renewables October 2013 to September 2018 Trevor I. Mihalik 56 Executive Vice President and Chief Financial Officer May 2018 to present Senior Vice President December 2013 to April 2018 Controller and Chief Accounting Officer July 2012 to April 2018 Peter R. Wall 51 Senior Vice President April 2020 to present Controller and Chief Accounting Officer May 2018 to present Vice President May 2018 to April 2020 Vice President and Chief Financial Officer, Sempra Infrastructure January 2017 to April 2018 Karen L. Sedgwick 56 Chief Administrative Officer and Chief Human Resources Officer December 2021 to present Senior Vice President and Chief Human Resources Officer September 2020 to December 2021 Chief Human Resources Officer and Chief Administrative Officer, SDGE April 2019 to September 2020 Vice President and Treasurer August 2018 to April 2019 Vice President, Audit Services January 2014 to August 2018 ##TABLE_END(1) Ages are as of February 28, 2023. 2022 Form 10-K | 33 Table of Contents

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##TABLE_START INFORMATION ABOUT EXECUTIVE OFFICERS AT SDGE Name Age (1) Positions held over last five years Time in position Caroline A. Winn 59 Chief Executive Officer August 2020 to present Chief Operating Officer January 2017 to July 2020 Bruce A. Folkmann 55 President August 2020 to present Chief Financial Officer March 2015 to present Senior Vice President August 2019 to July 2020 Controller, Chief Accounting Officer and Treasurer March 2015 to August 2020 Vice President March 2015 to August 2019 Vice President, Controller, Chief Financial Officer, Chief Accounting Officer and Treasurer, SoCalGas March 2015 to June 2019 Kevin Geraghty 57 Chief Operating Officer and Chief Safety Officer June 2022 - Present Chief Safety Officer January 2021 - June 2022 Senior Vice President - Electric Operations July 2020 - June 2022 Chief Operating Officer and Senior Vice President, Operations, Nevada Energy, an electric and natural gas public utility in Nevada October 2017 - May 2020 Valerie A. Bille 44 Vice President, Controller, Chief Accounting Officer and Treasurer August 2020 to present Assistant Controller, Sempra June 2019 to August 2020 Assistant Controller June 2018 to June 2019 Director, Utility Financial Reporting June 2017 to June 2018 Erbin B. Keith 62 Senior Vice President, General Counsel, Chief Risk Officer October 2022 to present Deputy General Counsel, Sempra March 2019 to October 2022 Chief Regulatory Officer and Special Counsel, Sempra September 2017 to March 2019 ##TABLE_END (1) Ages are as of February 28, 2023. ##TABLE_START INFORMATION ABOUT EXECUTIVE OFFICERS AT SOCALGAS Name Age (1) Positions held over last five years Time in position Scott D. Drury 57 Chief Executive Officer August 2020 to present President, SDGE January 2017 to July 2020 Maryam S. Brown 47 President March 2019 to present Vice President of Federal Government Affairs, Sempra September 2016 to March 2019 Jimmie I. Cho 58 Chief Operating Officer January 2019 to present Senior Vice President of Customer Services and Gas Distribution Operations April 2018 to January 2019 Senior Vice President of Gas Distribution Operations, SDGE April 2018 to January 2019 Senior Vice President of Gas Engineering and Distribution Operations, SoCalGas and SDGE October 2017 to April 2018 Mia L. DeMontigny 50 Senior Vice President July 2022 to present Chief Financial Officer, Chief Accounting Officer and Treasurer June 2019 to present Controller June 2019 to July 2022 Vice President June 2019 to August 2021 Assistant Controller, Sempra August 2015 to June 2019 David J. Barrett 58 Senior Vice President July 2022 to present General Counsel January 2019 to present Vice President January 2019 to July 2022 Associate General Counsel of Gas Infrastructure, Sempra June 2018 to January 2019 Assistant General Counsel of Gas Infrastructure, Sempra February 2017 to June 2018 ##TABLE_END(1) Ages are as of February 28, 2023. 2022 Form 10-K | 34 Table of Contents Human Capital Our ability to advance our mission to be North Americas premier energy infrastructure company largely depends on the safety, engagement, and responsible actions of our employees. Safety is foundational at Sempra and its subsidiaries. We strive to foster a strong safety culture and reinforce this culture through training programs, benchmarking, review and analysis of safety trends, and sharing lessons learned from safety incidents across our businesses. Our businesses also engage in safety-related scenario planning and simulation, develop and implement operational contingency plans, and review safety plans and procedures with work crews regularly. We also participate in emergency planning and preparedness in the communities we serve and train critical employees in emergency management and response each year. The Safety, Sustainability and Technology committee of the Sempra board of directors assists the board in overseeing the corporations oversight programs and performance related to safety, and our executives annual incentive compensation is based in part on safety metrics established by the Compensation and Talent Development Committee of the Sempra board of directors. Our overall culture is another important aspect of our ability to advance our mission. We embrace diversity in our workforce and strive to create a high-performing, inclusive and supportive workplace where employees of all backgrounds and experiences feel valued and respected. We invest in recruiting, developing and retaining high-potential employees who represent the communities we serve, and we provide a range of programs to advance those objectives, including internal and external mentoring and leadership training and workshops, employee resource groups, and a benefits package including wellness benefits and a tuition reimbursement program. We also invest in internal communications programs, including in-person and virtual learning and networking opportunities as well as regular executive communications to employees on topics of interest. In addition, we offer a variety of employee community service opportunities and, at our U.S. operations, we support employees personal volunteering and charitable giving through Sempras charitable matching program. Employees participate in annual ethics and compliance training, which includes a review of Sempras Code of Business Conduct as well as information about resources such as Sempras ethics and compliance helpline. We measure culture and employee engagement through a variety of channels including pulse surveys, suggestion boxes and a biannual engagement survey administered by a third party. The table below shows the number of employees for each of our registrants at December 31, 2022, as well as the percentage of those employees represented by labor unions under various collective bargaining agreements that generally cover wages, benefits, working conditions and other terms and conditions of employment. We did not experience any major work stoppages in 2022 and we maintain constructive relations with our labor unions. ##TABLE_START NUMBER OF EMPLOYEES Number of employees % of employees covered under collective bargaining agreements % of employees covered under collective bargaining agreements expiring within one year Sempra (1) 15,785 37 % % SDGE 4,633 30 % % SoCalGas 8,460 53 % % ##TABLE_END(1) Excludes employees of equity method investees. COMPANY WEBSITES Company website addresses are: Sempra www.sempra.com SDGE www.sdge.com SoCalGas www.socalgas.com We make available free of charge on the Sempra website, and for SDGE and SoCalGas, via a hyperlink on their websites, annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the

SEC. The references to our websites in this report are not active hyperlinks and the information contained on, or that can be accessed through, the websites of Sempra, SDGE and SoCalGas or any other website referenced herein is not a part of or incorporated by reference in this report or any other document that we file with or furnish to the SEC. 2022 Form 10-K | 35 Table of Contents ##TABLE_START ##TABLE_ENDITEM 1A. RISK FACTORS When evaluating our company and its subsidiaries and any investment in our or their securities, you should carefully consider the following risk factors and all other information contained in this report and the other documents we file with the SEC (including those filed subsequent to this report). We also may be materially harmed by risks and uncertainties not currently known to us or that we currently consider immaterial. If any of these risks occurs, our results of operations, financial condition, cash flows and/or prospects could be materially adversely affected, our actual results could differ materially from those expressed in any forward-looking statements made by us or on our behalf, and the trading price of our securities and those of our subsidiaries could decline. These risk factors are not prioritized in order of importance or materiality, and they should be read in conjunction with the other information in this report, including the information set forth in the Consolidated Financial Statements and in Part II Item 7. MDA. RISKS RELATED TO SEMPRA Operational and Structural Risks Sempras cash flows, ability to pay dividends and ability to meet its debt obligations largely depend on the performance of its subsidiaries and entities accounted for as equity method investments. We are a holding company and substantially all our assets are owned by our subsidiaries or entities we do not control, including equity method investments. Our ability to pay dividends and meet our debt and other obligations largely depends on cash flows from our subsidiaries and equity method investments, which in turn depend on their ability to execute their business strategies and generate cash flows in excess of their own expenditures, dividend payments to third-party owners (if any) and debt and other obligations. In addition, entities accounted for as equity method investments, which we do not control, and our subsidiaries are all separate and distinct legal entities that are not obligated to pay dividends or make loans or distributions to us and could be precluded from doing so by legislation, regulation, court order or contractual restrictions, in times of financial distress or in other circumstances. The inability to access capital from our subsidiaries and entities accounted for as equity method investments could have a material adverse effect on our results of operations, financial condition, cash flows and/or prospects. Sempras rights to the assets of its subsidiaries and equity method investments are structurally subordinated to the claims of each entitys trade and other creditors. If Sempra is a creditor of any such entity, its rights as a creditor would be effectively subordinated to any security interest in the entitys assets and any indebtedness of the entity senior to that held by Sempra. In addition, Sempra may elect to make capital contributions to its subsidiaries, which are not required to be repaid and generally are structurally subordinated to claims by creditors of the applicable subsidiary. Sempra has substantial investments in and obligations arising from businesses it does not control or manage or in which it shares control. We have investments in businesses we do not control or manage or in which we share control. In some cases, we engage in arrangements with or for these businesses that could expose us to risks in addition to our investment, including guarantees, indemnities and loans. For businesses we do not control, we are subject to the decisions of others, which may not always be in our interest and could negatively affect us. When we share control of a business with other owners, any disagreements among the owners about strategy, financial, operational, transactional or other important matters could hinder the business from moving forward with key initiatives or taking other actions and could negatively affect the relationships among the owners and the efficient functioning of the business. In addition, irrespective of whether or not we control these businesses, we could be responsible for liabilities or losses related to these businesses or elect to make capital contributions to these businesses. Any such circumstance could materially adversely affect our results of operations, financial condition, cash flows and/or prospects. We discuss these investments in Note 6 of the Notes to Consolidated Financial Statements. Our business could be negatively affected by activist shareholders. Activist shareholders may engage in proxy solicitations, advance shareholder proposals or otherwise attempt to effect changes in or assert influence on our board of directors and management. In taking these steps, activist shareholders could seek to acquire our capital stock, which at certain ownership levels could threaten our ability to use some or all our NOL carryforwards if our corporation experiences an ownership change under applicable tax rules. Responding to activist shareholders could require us to 2022 Form 10-K | 36 Table of Contents incur legal and advisory fees, proxy solicitation expenses and administrative and associated costs and require time and attention by our board of directors and management, diverting their attention from the pursuit of our business strategies. Any perceived uncertainties about our future direction or control, our ability to execute our strategies, or the composition of our board of directors or management team arising from activist shareholder attention or other action could lead to a perception of instability or a change in the direction of our business, which could be exploited by our competitors and/or other activist shareholders, result in the loss of business opportunities, and make it more difficult to pursue our strategic initiatives or attract and retain qualified personnel and business partners, any of which could have a material adverse effect on our results of operations, financial condition, cash flows and/or prospects. Further, any such actions could cause fluctuations in the trading prices of our securities based on temporary or speculative market perceptions or other factors. Financial and Capital Stock-Related Risks Any impairment of our assets or investments could negatively impact us. We could experience a reduction in the fair value of our assets, including our long-lived assets, intangible assets or goodwill, and/or our investments that we account for under the equity method upon the occurrence of many of the risks discussed in these risk factors and elsewhere in this report, including any closure of the Aliso Canyon natural gas storage facility without adequate cost recovery, any inability to operate our existing facilities or develop new projects in Mexico due to proposed changes to existing laws or regulations or other circumstances affecting the energy sector or our assets in that country, and more generally any loss of permits or approvals that requires us to adjust or cease certain operations and any investment in capital projects that do not receive required approvals or are changed, abandoned or otherwise not completed. Any such reduction in the fair value of our assets or investments could result in an impairment loss that could materially adversely affect our results of operations for the period in which the charge is recorded. We discuss our impairment testing of long-lived assets and goodwill and the factors considered in such testing in Part II Item 7. MDA Critical Accounting Estimates and in Note 1 of the Notes to Consolidated Financial Statements. The economic interest, voting rights and market value of our outstanding common and preferred stock may be adversely affected by any additional equity securities we may issue. At February 21, 2023, we had 314,569,519 shares of our common stock and 900,000 shares of our non-convertible series C preferred stock outstanding. We may seek to raise capital by issuing additional equity or convertible debt securities, which may materially dilute the voting rights and economic interests of holders of our outstanding common and preferred stock and materially adversely affect the trading price of our common and preferred stock. Dividend requirements associated with our preferred stock subject us to risks. Any failure to pay scheduled dividends on our series C preferred stock when due would have a material adverse impact on the market price of our securities and would prohibit us, under the terms of the series C preferred stock, from paying cash dividends on or repurchasing shares of our common stock (subject to limited exceptions) until we have paid all accumulated and unpaid dividends on the series C preferred stock. Additionally, the terms of the series C preferred stock generally provide that if dividends on any shares of the preferred stock have not been declared and paid or have been declared but not paid for three or more semi-annual dividend periods, whether or not consecutive, the holders of the preferred stock would be entitled to elect two additional members to our board of directors, subject to certain terms and limitations. Our common stock is listed on the Mexican Stock Exchange and registered with the CNBV, which subjects us to additional regulation and liability in Mexico. In addition to being listed for trading on the NYSE, our common stock is listed for trading on the Mexican Stock Exchange and registered with the CNBV. Such listing and registration subjects us to filing and other requirements in Mexico that could increase costs and increase performance risk of personnel given additional responsibilities. In addition, the CNBV, as the Mexican securities market regulator, has the authority to make inspections of Sempras business, primarily in the form of requests for information and documents; impose fines or other penalties on Sempra and its directors and officers for violations of Mexican securities laws and regulations; and seek criminal liability for certain actions conducted or with effects in Mexico. The occurrence of any of these risks could materially adversely affect our results of operations, financial condition, cash flows and/or prospects. 2022 Form 10-K | 37 Table of Contents RISKS RELATED TO ALL SEMPRA BUSINESSES Operational Risks Our businesses are subject to risks arising from their infrastructure and information systems. Our businesses facilities and the information systems that interconnect and/or manage them are subject to risks of, among other things, potential breakdown or failure of equipment or processes due to aging infrastructure and systems; human error; shortages of or delays in obtaining equipment, materials, commodities or labor, which may be exacerbated by current or future supply chain constraints and tight labor market conditions, and increases to the costs of these items due to inflationary pressures or otherwise, which may not be recoverable in a timely manner or at all; operational restrictions resulting from environmental requirements or governmental interventions; inability to enter into, maintain, extend or replace long-term supply or transportation contracts; and performance below expected levels. Even though our businesses undertake capital investment projects to construct, replace, maintain, improve and upgrade facilities and systems, such projects may not be effective at managing the aforementioned risks, and may involve significant costs that may not be recoverable and challenges in achieving completion. We often rely on third parties, including contractors, to perform work related to these projects and other maintenance activities, which may subject us to increased risks because we manage the safety and quality of work performed by third parties and may retain liability for their work. Because our facilities are interconnected with those of third parties, including receiving natural gas supply from third party pipelines and power generation facilities that produce most of the power that we distribute to customers, the operation of our facilities could also be adversely affected by these or similar risks to the systems of such third parties, many of which may be unanticipated or uncontrollable by us. Additional risks associated with our businesses ability to safely and reliably construct, replace, operate, maintain, improve and upgrade their respective facilities and systems, many of which are beyond our control, include: failure to meet customer demand for electricity and/or natural gas, including electrical blackouts or curtailments or gas outages natural gas surges into homes or other properties the release of hazardous or toxic substances, including gas leaks inadequate emergency preparedness plans and the failure to respond effectively to catastrophic events The occurrence of any of these events could affect supply and demand for electricity, natural gas or other forms of energy, cause unplanned outages, damage our businesses assets and/or operations, damage the assets and/or operations of third parties on which our businesses rely, damage property owned by customers or others, and cause personal injury or death. In addition, if we are unable to defend and retain title to the properties we own or if we are unable to obtain or retain rights to construct and operate on the properties we do not own in a timely manner, on reasonable terms or at all, we could lose our rights to occupy and use these properties and the related facilities, which could result in modification, delay or curtailment of existing or proposed operations or projects, increase our costs, and result in breaches of one or more permits or contracts related to the affected facilities that could lead to legal costs, impairments or fines or penalties. Any such outcome could have a material adverse effect on our results of operations, financial condition, cash flows and/or prospects. Severe weather, natural disasters and other similar events could materially adversely affect us. Our facilities and infrastructure, including projects in development and under construction, may be damaged by severe weather, natural disasters, accidents, explosions or acts of terrorism, war or criminality. Because we are in the business of using, storing, transporting and disposing of highly flammable, explosive and radioactive materials and operating highly energized equipment, the risks such incidents may pose to our facilities and infrastructure, as well as the risks to the surrounding communities for which we could be held responsible, are substantially greater than the risks such incidents pose to a typical business. Such incidents could result in business and project development disruptions, power or gas outages, property damage, injuries and loss of life for which we could be liable and could cause secondary incidents that also may have these or other negative effects, such as fires; leaks of natural gas, natural gas odorant, propane, ethane, other GHG emissions or radioactive material; spills or other damage to natural resources; or other nuisances to affected communities. Any of these occurrences could decrease revenues and earnings and/or increase costs, including maintenance costs or restoration expenses, amounts associated with claims against us, and regulatory fines, penalties and disallowances. In some cases, we may be liable for damages even though we are not at fault, such as when the doctrine of inverse condemnation applies, which we discuss below under Risks Related to Sempra California Operational Risks. For our regulated utilities, these costs may not be recoverable in rates. Insurance coverage for these costs may increase or become prohibitively expensive, be disputed by insurers, or become unavailable for certain of these risks or at sufficient levels, and any insurance proceeds may be insufficient to cover our losses or liabilities due to limitations, exclusions, high deductibles, failure to comply with procedural requirements or other factors. Such incidents that do not directly 2022 Form 10-K | 38 Table of Contents affect our facilities may impact our business partners, supply chains and transportation channels, which could negatively impact construction projects and our ability to provide electricity and natural gas to customers. Moreover, weather-related incidents have become more prevalent, unpredictable and severe as a result of climate change or other factors, which could have a greater impact on our businesses than currently anticipated and, for our regulated utilities, rates may not be adequately or timely adjusted to reflect any such increased impact. Any such outcome could have a material adverse effect on our results of operations, financial condition, cash flows and/or prospects. In addition to general information and cyber risks that all large corporations face, we face evolving cybersecurity risks associated with the energy grid, natural gas pipelines, storage and other infrastructure and protecting sensitive and confidential customer and employee information. Our use of complex technologies and systems in our operations, including deployment of any new technologies, and our collection and retention of sensitive information, represent large-scale opportunities for attacks on or other failures to protect our information systems, confidential information and energy grid and natural gas infrastructure. In particular, cyber-attacks targeting utility systems and other energy infrastructure, as well as the impacts of these attacks on companies and their communities, are increasing in sophistication, magnitude and frequency and may further increase in connection with certain geopolitical events, such as the war in Ukraine. Additionally, SDGE and SoCalGas are increasingly required to disclose large amounts of data (including customer personal information and energy use data) to support changes to Californias electricity and gas markets related to grid modernization and customer choice as well as energy efficiency, demand response and conservation, increasing the risks of inadvertent disclosure or other unauthorized access of sensitive information. Further, the virtualization of many business activities increases cyber risk, and generally there has been an associated increase in targeted cyber-attacks. Moreover, all our businesses operating in California (and any other states and countries where we do business that adopt similar laws) are subject to enhanced state privacy laws, which require companies that collect information about California residents to, among other things, make disclosures to consumers about their data collection, use and sharing practices; allow consumers to opt out of certain data sharing with third parties; and assume liability under a new cause of action for unauthorized disclosure of certain highly sensitive personal information. Although we invest in risk management and information security measures for the protection of our systems and information, these measures could be insufficient or otherwise fail. The costs and operational consequences of implementing, maintaining and enhancing these protection measures are significant, and they could materially increase to address increasingly intense and complex cyber risks. We often rely on third-party vendors to deploy new business technologies and maintain, modify and update our systems, and these third parties may not have adequate risk management and information security measures with respect to their systems. Any cyber-attack, including ransomware attacks, on our or our vendors information systems or the integrity of the energy grid, our pipelines or our distribution, storage and other infrastructure, or unauthorized access, damage or improper disclosure of confidential information, could result in disruptions to our business operations, regulatory compliance failures, inabilities to produce accurate and timely financial statements, energy delivery failures, financial and reputational loss, customer dissatisfaction, litigation, violation of privacy laws and fines or penalties, any of which could have a material adverse effect on our results of operations, financial condition, cash flows and/or prospects. Although Sempra currently maintains cyber liability insurance, this insurance is limited in scope and subject to exceptions, conditions and coverage limitations and may not cover any or even a substantial portion of the costs associated with any compromise of our information systems or confidential information, and there is no guarantee that the insurance we currently maintain will continue to be available at rates we believe are commercially reasonable. We seek growth opportunities in the market organically and inorganically, including through the acquisition of, or partnerships in, operating companies. We diligently analyze the financial viability of each acquisition, partnership and JV we pursue. However, our diligence may prove to be insufficient and there could be latent, unforeseen defects. In addition, we may not realize all the anticipated benefits from future acquisitions, partnerships or JVs for various reasons, including difficulties integrating operations and personnel to our standards or in a timely manner, higher and unexpected acquisition and operating costs, unknown liabilities, and fluctuations in markets. Any of these outcomes could materially adversely affect our results of operations, financial condition, cash flows and/or prospects. Increasing activities and projects intended to advance new energy technologies could introduce new risks to our businesses. We regularly undertake or become involved in research and development projects and other activities designed to develop new technologies in the energy space, including those related to hydrogen, energy storage, carbon sequestration, grid modernization and others. These activities and projects can involve significant employee time, as well as substantial capital resources that may 2022 Form 10-K | 39 Table of Contents not be recoverable in rates or, with respect to our non-regulated utility businesses, may not be able to be passed through to customers. We may also seek a variety of federal and state funding opportunities for these activities and projects (such as loans and grants, including in conjunction with third-party commercial or governmental entities), which may involve significant employee time and effort and increased compliance requirements with no guarantee that any such funding would be received. In addition, the timing to complete these activities and projects is inherently uncertain and may require significantly more time and funding than we initially anticipate. Moreover, many of these technologies are in the early stage of development, and the applicable activities and projects may not be completed or the applicable technologies may not prove economically and technically feasible. If any of these circumstances occurs, we may not receive an adequate or any return on our investment and other resources invested in these activities and our results of operations, financial condition, cash flows and/or prospects could be materially adversely affected. The operation of our facilities depends on good labor relations with our employees. Several of our businesses have in place collective bargaining agreements with different labor unions, which are generally negotiated on a company-by-company basis. Any failure to negotiate and reach an agreement on these labor contracts as they are up for renewal could result in strikes, boycotts or other labor disruptions. Any such labor disruption or negotiated wage or benefit increases, whether due to union activities, employee turnover or otherwise, could have a material adverse effect on our results of operations, financial condition, cash flows and/or prospects. Our businesses depend on the performance of counterparties, and any performance failures by these counterparties could materially adversely affect us. Our businesses depend on the performance of business partners, customers, suppliers and other counterparties who owe money or commodities as a result of market transactions or other long-term arrangements. If they fail to perform their obligations in accordance with these arrangements, we may need to enter into alternative arrangements or honor our underlying commitments at then-current market prices, which may result in additional losses to us to the extent of amounts already paid to such counterparties. Any efforts to enforce the terms of these arrangements through legal or other means could involve significant time and costs and would be unpredictable and may not be successful. In addition, many of these arrangements, including our relationships with the applicable counterparties, are important for the conduct and growth of our businesses. We also may not be able to secure replacement agreements with other counterparties on favorable terms, in a timely manner or at all if any of these arrangements terminate. Further, we often extend credit to customers and other counterparties and, although we perform credit analyses prior to extending credit, we may not be able to collect the amounts owed to us, which presents an increased risk for our long-term supply, sales and capacity contracts. The failure of any of our counterparties to perform in accordance with their arrangements with us could materially adversely affect our results of operations, financial condition, cash flows and/or prospects. Sempra Infrastructures obligations and those of its LNG suppliers are contractually subject to suspension or termination for force majeure events, which generally are beyond the control of the parties, and limitations of remedies for other failures to perform, including limitations on damages that may prohibit recovery of costs incurred for any breach of an agreement. Any such occurrence could have a material adverse effect on our results of operations, financial condition, cash flows and/or prospects. Sempra Infrastructure engages in JVs and invests in companies in which other equity partners may have or share with us control over the applicable project or investment. Sempra Texas Utilities also invests in companies that it does not control or manage. We discuss the risks related to these arrangements above under Risks Related to Sempra Operational and Structural Risks. Our businesses face risks related to the COVID-19 pandemic. The COVID-19 pandemic has materially impacted communities, supply chains, economies and markets around the world since March 2020. To date, the COVID-19 pandemic has not had a material impact on our results of operations. However, Sempra and some or all its businesses have been and could continue to be impacted by this pandemic or any future pandemic in a number of ways, including: Disruption in supply chains and the capital markets, which has affected and could further affect liquidity, strategic initiatives and prospects, including in some cases a slowdown of planned capital spending Customer-protection measures implemented by SDGE and SoCalGas, including suspending service disconnections due to nonpayment for all customers early in the pandemic (except for SoCalGas noncore customers and, since the second half of 2022, SDGEs and SoCalGas commercial and industrial customers), waiving late payment fees, offering flexible payment plans and automatically enrolling residential and small business customers with past-due balances in long-term repayment plans, which have collectively resulted in a reduction in payments from SDGE and SoCalGas customers and an increase in uncollectible accounts that could become material and may not be fully recoverable 2022 Form 10-K | 40 Table of Contents Precautionary, preemptive and responsive actions taken by our current and prospective counterparties, customers and partners, as well as regulators and other governing bodies that affect our businesses, which have affected and could further affect our operations, results, liquidity and ability to pursue capital projects and strategic initiatives Any of these impacts could have a material adverse effect on our results of operations, financial condition, cash flows and/or prospects. We will continue to actively monitor the effects of the COVID-19 pandemic and may take further actions that alter our business operations as may be required by federal, state or local authorities, or that we determine are necessary for the safety of our employees, customers, partners and suppliers and, generally, the communities we serve. However, we cannot at this time predict the extent to which the COVID-19 pandemic may further impact our businesses. Financial Risks Our debt service obligations expose us to risks and could require additional equity securities issuances by Sempra and sales of equity interests in various subsidiaries or projects under development. Our businesses have debt service obligations, which could have a material adverse effect on our results of operations, financial condition, cash flows and/or prospects by, among other things: making it more difficult and costly for each of these businesses to service, pay or refinance their debts as they come due, particularly during adverse economic or industry conditions or in periods of significant increases in interest rates limiting flexibility to pursue strategic opportunities or react to business developments or changes in the industry sectors in which they operate requiring cash to be used for debt service payments, thereby reducing the cash available for other purposes causing lenders to require materially adverse terms in the instruments for new debt, such as restrictions on uses of proceeds or other assets or limitations on incurring additional debt, creating liens, paying dividends, repurchasing stock, making investments or receiving distributions from subsidiaries or equity method investments Sempras goal is to maintain or improve its credit ratings, but it may not be able to do so. To maintain these credit ratings, we may seek to reduce our outstanding indebtedness or our need for additional indebtedness with the proceeds from issuances of equity securities by Sempra or the sale of equity interests in our subsidiaries or development projects. We may not be able to complete any such equity sales on terms we consider acceptable or at all, and any new equity issued by Sempra may dilute the voting rights and economic interests of existing holders of Sempras common and preferred stock. Any such outcome could have a material adverse effect on Sempras results of operations, financial condition, cash flows and/or prospects. The availability and cost of debt or equity financing could be negatively affected by market and economic conditions and other factors, and any such effects could materially adversely affect us . Our businesses are capital-intensive, with significant capital spending expected in future periods. In general, we rely on long-term debt to fund a significant portion of our capital expenditures and repay outstanding debt and we rely on short-term borrowings to fund a significant portion of day-to-day business operations. Sempra may also seek to raise capital by issuing equity or selling equity interests in our subsidiaries or investments. Limitations on the availability of credit, increases in interest rates or credit spreads due to inflationary pressures or otherwise or other negative effects on the terms of any financing we pursue could cause us to fund operations and capital expenditures at a higher cost or fail to raise our targeted amount of funding, which could negatively impact our ability to meet contractual and other commitments, progress development projects, make non-safety related capital expenditures and effectively sustain operations. Any of these outcomes could materially adversely affect our results of operations, financial condition, cash flows and/or prospects. In addition to market and economic conditions, factors that can affect the availability and cost of capital include: adverse changes to laws and regulations, including recent and proposed changes to the regulation of the energy market in Mexico the overall health of the energy industry volatility in electricity or natural gas prices for Sempra, SDGE and SoCalGas, risks related to California wildfires for Sempra, SDGE and SoCalGas, any deterioration of or uncertainty in the political or regulatory environment for local natural gas distribution companies operating in California credit ratings downgrades 2022 Form 10-K | 41 Table of Contents We are subject to risks due to uncertainty relating to the calculation of LIBOR and its scheduled discontinuance. Certain of our financial and commercial agreements, including those for variable rate indebtedness, as well as interest rate derivatives, incorporate LIBOR as a benchmark for establishing certain rates. As directed by the U.S. Federal Reserve, banks ceased making new LIBOR-based issuances at the end of 2021, and publication of certain key U.S. dollar LIBOR tenors for existing loans is expected to cease in mid-2023. These events could cause LIBOR to perform differently than it has performed historically. Use of the SOFR, which has been identified as the replacement benchmark rate for LIBOR, may result in interest payments that are higher than expected or that do not otherwise correlate over time with the payments that would have been made using LIBOR. Changes to or the discontinuance of LIBOR, any uncertainty regarding such changes or discontinuance, and the performance and characteristics of alternative benchmark rates, could negatively affect our existing and future variable rate indebtedness and interest rate hedges and the cost of doing business under our commercial agreements that incorporate LIBOR, SOFR or other alternative benchmark rates, and could require us to seek to amend the terms of the relevant indebtedness or agreements, which may not be possible and/or may require us to accept terms that are materially worse than existing terms. The occurrence of any of these risks could have a material adverse effect on our results of operations, financial condition, cash flows and/or prospects. Credit rating agencies may downgrade our credit ratings or place those ratings on negative outlook. Credit rating agencies routinely evaluate Sempra, SDGE, SoCalGas and SI Partners and certain of our other businesses, and their ratings are based on a number of factors, including the factors described below and the ability to generate cash flows; level of indebtedness; overall financial strength; specific transactions or events, such as share repurchases and significant litigation; the status of certain capital projects; and the state of the economy and our industry generally. These credit ratings could be downgraded or other negative credit rating actions could occur at any time. We discuss these credit ratings in Part II Item 7. MDA Capital Resources and Liquidity. For Sempra, the Rating Agencies have noted that the following events, among others, could lead to negative ratings actions: expansion of natural gas liquefaction projects or other unregulated businesses in a manner inconsistent with its present level of credit quality Sempras consolidated financial measures do not improve, or it fails to meet certain financial credit metrics catastrophic wildfires caused by SDGE or by any

California electric IOUs that participate in the Wildfire Fund, which could exhaust the fund considerably earlier than expected For SDGE, the Rating Agencies have noted that the following events, among others, could lead to negative ratings actions: catastrophic wildfires caused by SDGE or by any California electric IOUs that participate in the Wildfire Fund, which could exhaust the fund considerably earlier than expected a consistent weakening of SDGEs financial metrics or a deterioration in the regulatory environment a ratings downgrade at Sempra For SoCalGas, the Rating Agencies have noted that the following events, among others, could lead to negative ratings actions: SoCalGas financial measures consistently weaken, or it fails to meet certain financial credit metrics SoCalGas experiences increased business risk, including a deterioration in the regulatory environment, leading to weakening of its stand-alone business risk profile a ratings downgrade at Sempra For SI Partners, the Rating Agencies have noted that the following events, among others, could lead to negative ratings actions: SI Partners failure to meet certain financial credit metrics a deterioration in SI Partners business risk profile, including incremental construction risk or adverse changes in the operating environment in Mexico a ratings downgrade at Sempra, IEnova and/or Cameron LNG, LLC A downgrade of any of our businesses credit ratings or ratings outlooks, as well as the reasons for such downgrades, may materially adversely affect the market prices of our securities, the interest rates at which borrowings can be made and debt securities issued, and the various fees on our credit facilities. This could make it more costly for the affected businesses to borrow money, issue securities and/or raise other types of capital, any of which could materially adversely affect our ability to meet our debt obligations and contractual commitments, and our results of operations, financial condition, cash flows and/or prospects. 2022 Form 10-K | 42 Table of Contents We do not fully hedge our assets or contract positions against changes in commodity prices or interest rates, and for those positions that are hedged, our hedging procedures may not mitigate our risk as expected or prevent us from experiencing losses. We have used and may continue to use forward contracts, futures, financial swaps and/or options, among other mechanisms, to hedge our known or anticipated purchase and sale commitments, inventories of natural gas and LNG, natural gas storage and pipeline capacity and electric generation capacity in an effort to reduce our financial exposure related to commodity price fluctuations. We do not hedge the entire exposure to market price volatility of our assets or our contract positions, and the extent of the coverage to these exposures varies over time. In addition, we have used and may continue to use similar financial instruments to hedge against changes in interest rates. Certain derivative securities we use to hedge are recorded at fair value through earnings to reflect movements in the price of the security, which has in the past and could in the future create volatility in our earnings (such as the significantly higher unrealized losses on commodity derivatives that we recognized in 2022 compared to 2021 as we discuss in Part II Item 7. MDA Results of Operations). To the extent we have unhedged positions, or if our hedging strategies do not work as expected, fluctuating commodity prices could have a material adverse effect on our results of operations, financial condition, cash flows and/or prospects. Certain of the contracts we may use for hedging purposes are subject to fair value accounting, which may result in gains or losses in earnings for those contracts that may not reflect the associated gains or losses of the underlying position being hedged and could result in fluctuations of our results from period to period. Risk management procedures may not prevent or mitigate losses. Although we have in place risk management and control systems designed to quantify and manage risk, these systems may not prevent material losses. Risk management procedures may not always be followed as intended or function as expected. In addition, daily VaR and loss limits, which are primarily based on historic price movements and which we discuss in Part II Item 7A. Quantitative and Qualitative Disclosures About Market Risk, may not protect us from losses if prices significantly or persistently deviate from historic prices. As a result of these and other factors, our risk management procedures and systems may not prevent or mitigate losses that could materially adversely affect our results of operations, financial condition, cash flows and/or prospects. Market performance or changes in other assumptions could require unplanned contributions to pension and PBOP plans. Sempra, SDGE and SoCalGas provide defined benefit pension and PBOP plans to eligible employees and retirees. The cost of providing these benefits is affected by many factors, including the market value of plan assets and the other factors described in Note 9 of the Notes to Consolidated Financial Statements. A decline in the market value of plan assets or an adverse change in any of these other factors could cause a material increase in our funding obligations for these plans, which could have a material adverse effect on our results of operations, financial condition, cash flows and/or prospects. Legal and Regulatory Risks Our businesses require numerous permits, licenses, franchises and other approvals from various governmental agencies, and the failure to obtain or maintain any of them, or lengthy delays in obtaining them, could materially adversely affect us. Our businesses require numerous permits, licenses, rights-of-way, franchises, certificates and other approvals from federal, state, local and foreign governmental agencies. These approvals may not be granted in a timely manner or at all or may be modified, rescinded or fail to be extended for a variety of reasons. Obtaining or maintaining these approvals could result in higher costs or the imposition of conditions or restrictions on our operations. For example, SoCalGas franchise agreement with Los Angeles County is scheduled to expire in June 2023. Further, these approvals require compliance by us and may require compliance by our customers, which could result in modification, suspension or rescission and subject us to fines and penalties in the event of noncompliance. If one or more of these approvals were to be suspended, rescinded or otherwise terminated, including due to expiration or legal or regulatory changes, or modified in a manner that makes our continued operation of the applicable business prohibitively expensive or otherwise undesirable or impossible, we may be required to adjust or temporarily or permanently cease certain of our operations, sell the associated assets or remove them from service and/or construct new assets intended to bypass the impacted area, in which case we may lose some of our rate base or revenue-generating assets, our development projects may be negatively affected and we may incur impairment charges or other costs that may not be recoverable. The occurrence of any of these events could materially adversely affect our results of operations, financial condition, cash flows and/or prospects. We may invest funds in capital projects prior to receiving all regulatory approvals. If there is a delay in obtaining these approvals; if any approval is conditioned on changes or other requirements that increase costs or impose restrictions on our existing or 2022 Form 10-K | 43 Table of Contents planned operations; if we fail to obtain or maintain these approvals or comply with them or other applicable laws or regulations; if we are involved in litigation that adversely impacts any approval or rights to the applicable property or assets; or if management decides not to proceed with a project, we may be unable to recover any or all amounts invested in that project. Any such occurrence could cause our costs to materially increase, result in material impairments, and otherwise materially adversely affect our results of operations, financial condition, cash flows and/or prospects. Our businesses face climate change concerns and have environmental compliance and clean energy transition costs, which could have a material adverse effect on us. Climate change and the costs associated with its impacts and mitigation may have the potential to adversely affect our businesses, including by increasing the costs we incur to transmit energy and provide other services, impacting the demand for and consumption of the natural gas we distribute and the energy we transmit (due to changes in costs, weather patterns, the type of energy transmitted as a result of increasing customer preference for carbon-neutral and renewable sources of energy, and other factors), and affecting the economic health of the regions in which we operate. Our businesses are subject to extensive federal, state, local and foreign statutes, orders, rules and regulations relating to climate change and environmental protection. To comply with these requirements, we must expend significant capital and employee resources on (i) environmental monitoring, surveillance and other measures to track performance; (ii) acquisitions of pollution control equipment; (iii) mitigation efforts; and (iv) emissions fees, which could increase as a result of various factors we may not control, including changing laws and regulations, increased enforcement activities, delays in the renewal and issuance of permits, and changes to the mix of energy we are required to supply. In addition, we are generally responsible for hazardous substances and other contamination on and the conditions of our projects and properties, regardless of when these conditions arose and whether they are known or unknown. In addition, we could be liable for contamination at our former facilities and off-site waste disposal sites that have been used in our operations. For our regulated utilities, some of these costs may not be recoverable in rates. Failure to comply with environmental laws and regulations may subject our businesses to fines and penalties, including criminal penalties in some cases, and/or curtailment of our operations. Any of these outcomes could materially adversely affect our results of operations, financial condition, cash flows and/or prospects. Increasing international, national, regional, state and local-level environmental concerns and related new or proposed legislation and regulation or changes to existing legislation or regulation, such as increased requirements for monitoring and surveillance, disclosures on environmental performance and targets, pollution monitoring and control equipment, safety practices, emissions fees, taxes, penalties or other obligations or restrictions, may have material negative effects on our operations, operating costs, corporate planning, and the scope and economics of proposed expansions, infrastructure projects or other capital expenditures. In addition, existing and potential new or amended legislation and regulation relating to the control and reduction of GHG emissions and mitigating climate change may materially restrict our operations, negatively impact demand for our services, the natural gas we distribute and/or the energy we transmit, limit development opportunities, force costly or otherwise burdensome changes to our operations or otherwise materially adversely affect us. For example, SB 100 (enacted in 2018) and SB 1020 (enacted in 2022) requires each California electric utility, including SDGE, to procure at least 50% of its annual electric energy requirements from renewable energy sources by 2026, 60% by 2030, 90% by 2035, and 95% by 2040. State law also creates the policy of meeting all of Californias retail electricity supply with a mix of RPS Program-eligible and zero-carbon resources by 2045. The law also includes stipulations that this policy not increase carbon emissions elsewhere in the western grid and not allow resource shuffling, and requires that the CPUC, CEC, CARB and other state agencies incorporate this policy into all relevant planning. In addition, the Governor of California signed an executive order establishing a new statewide goal to achieve carbon neutrality as soon as possible, and no later than 2045, and achieve and maintain net negative emissions thereafter. The executive order calls on CARB to address this goal in future scoping plans, which affect several major sectors of Californias economy, including transportation, agriculture, development, industrial and others. California has issued new climate initiatives in line with this statewide goal, including two executive orders requiring sales of all passenger vehicles to be zero-emission by 2035. Moreover, the energy transition in California and elsewhere, including decarbonization goals, has introduced uncertainty in investor support over the long term, leading some to reduce investment in or divest from the energy sector. Maintaining investor confidence and attracting capital at a competitive cost will depend in part on successfully demonstrating our ability to reduce emissions associated with our operations and the energy we transmit, consistent with Sempras aim to have net-zero emissions by 2050 and SDGEs and SoCalGas aim to have net-zero emissions by 2045. Our ability to achieve this aim depends on many factors, some of which we do not control, including supportive energy laws and policies, development, availability and adoption of alternative fuels, successful research and development efforts focused on low-carbon technologies that are economically and technically feasible, cooperation from our partners, financing sources and commercial counterparties, customer participation in conservation and energy efficiency programs, and our ability to execute our planned investments in and advancement of our 2022 Form 10-K | 44 Table of Contents infrastructure. Although we have developed interim targets and various plans designed to support California in reaching its GHG emissions and renewable energy mandates and our own energy goals, we may not be successful. We will need to continue to expend capital and employee resources to develop and deploy new technologies and modernize grid systems in our efforts to support the clean energy transition in California and elsewhere and achieve our climate targets and those mandated by applicable authorities, which may not be recoverable in rates or, with respect to our non-regulated utility businesses, may not be able to be passed through to customers. Even if such costs are recoverable, the costs of these efforts and complying with these mandates, coupled with the necessary costs of investing for safety and reliability, may negatively impact the affordability of SDGEs and SoCalGas customer rates and, for our non-regulated utility businesses, may cause costs to increase to levels that reduce customer demand and growth. SDGE and SoCalGas, as well as any of our other businesses affected by GHG emissions mandates, may also be subject to fines and penalties if mandated renewable energy goals are not met, and all our businesses could suffer difficulties attracting investors and business partners, reputational harm and other negative effects if we do not meet or if we scale back our GHG emissions goals or there are negative views about our environmental disclosures or practices generally. Any of these outcomes could have a material adverse effect on our results of operations, financial condition, cash flows and/or prospects. Our businesses are subject to numerous governmental regulations and complex tax and accounting requirements and may be materially adversely affected by them or any changes to them. The electric power and natural gas industries are subject to numerous governmental regulations, and our businesses are also subject to complex tax and accounting requirements. These regulations and requirements may undergo changes at the federal, state, local and foreign levels, including in response to economic or political conditions. Compliance with these regulations and requirements, including in the event of changes to them or how they are implemented, interpreted or enforced, could increase our operating costs and materially adversely affect how we conduct our business. New tax legislation, regulations or interpretations or changes in tax policies in the U.S. or other countries in which we operate or do business could negatively affect our tax expense and/or tax balances and our businesses generally. Any failure to comply with these regulations and requirements could subject us to fines and penalties, including criminal penalties in some cases, and result in the temporary or permanent shutdown of certain facilities or operations. The occurrence of any of these risks could have a material adverse effect on our results of operations, financial condition, cash flows and/or prospects. Our operations are subject to rules relating to transactions among SDGE, SoCalGas and other Sempra businesses. These rules are commonly referred to as affiliate rules, and they primarily impact transmission supply, capacity and marketing activities, including restricting our ability to sell natural gas or electricity to, or trade with, SDGE and SoCalGas and their ability to complete these transactions with each other. These rules, as well as any changes to these rules or their interpretations or additional more restrictive CPUC or FERC rules related to transactions with affiliates, could materially adversely affect our operations and, in turn, our results of operations, financial condition, cash flows and/or prospects. We may be materially adversely affected by the outcome of litigation or other proceedings in which we are involved. Our businesses are involved in a number of lawsuits, binding arbitrations, regulatory investigations and other proceedings. We discuss material pending proceedings in Note 16 of the Notes to Consolidated Financial Statements. We have spent, and continue to spend, substantial money, time and employee and management focus on these lawsuits and other proceedings. The uncertainties inherent in lawsuits and other proceedings make it difficult to estimate with any degree of certainty the timing, costs and ranges of costs or effects of resolving these matters. In addition, juries have demonstrated a willingness to grant large awards, including punitive damages, in response to personal injury, product liability, property damage and other claims. Accordingly, actual costs incurred have and may continue to differ materially from insured or reserved amounts and may not be recoverable, in whole or in part, from insurance or in customer rates. Any of the foregoing could cause reputational damage and materially adversely affect our results of operations, financial condition, cash flows and/or prospects. 2022 Form 10-K | 45 Table of Contents RISKS RELATED TO SEMPRA CALIFORNIA Operational Risks Wildfires in California pose risks to Sempra California (particularly SDGE) and Sempra. Potential for Increased and More Severe Wildfires Over the past few years, California has been experiencing some of the largest wildfires (measured by acres burned) in its history. Frequent and severe drought conditions, inconsistent and extreme swings in precipitation, changes in vegetation, unseasonably warm temperatures, low humidity, strong winds and other factors have increased the duration of the wildfire season and the intensity, prevalence and difficulty of prevention and containment of wildfires in California, including in SDGEs and SoCalGas service territories. Changing weather patterns, including as a result of climate change, could cause these conditions to become even more extreme and unpredictable. These wildfires could jeopardize SDGEs and SoCalGas electric and natural gas infrastructure and third-party property and result in temporary power shortages in SDGEs and SoCalGas service territories. Certain of Californias local land use policies and forestry management practices have been relaxed to allow for the construction and development of residential and commercial projects in high-risk fire areas, which could lead to increased third-party claims and greater losses in the event of fires in these areas for which SDGE or SoCalGas may be liable. Any such wildfires in SDGEs and SoCalGas territories (or outside of these territories in the event the Wildfire Fund described below is materially diminished) could materially adversely affect SDGEs, SoCalGas and Sempras results of operations, financial condition, cash flows and/or prospects, which we discuss in this risk factor below and above under Risks Related to All Sempra Businesses Operational Risks. The Wildfire Legislation In July 2019, the Wildfire Legislation was signed into law, which we discuss in Note 1 of the Notes to Consolidated Financial Statements. The Wildfire Legislations revised legal standard for the recovery of wildfire costs may not be implemented effectively or applied consistently, we may not be eligible for the Wildfire Legislations cap on wildfire-related liability if SDGE fails to maintain a valid annual safety certification from the OEIS or meet other requirements of the legislation, and/or the Wildfire Fund could be exhausted due to claims against the fund by SDGE or other participating IOUs as a result of fires in their respective service territories, any of which could have a material adverse effect on Sempras and SDGEs results of operations, financial condition, cash flows and/or prospects. PGE has indicated that it will seek reimbursement from the Wildfire Fund for losses associated with the Dixie fire, which burned from July 2021 through October 2021 and was reported to be the largest single wildfire (measured by acres burned) in California history. In addition, the Wildfire Legislation did not change the doctrine of inverse condemnation, which imposes strict liability (meaning that liability is imposed regardless of fault) on a utility whose equipment, such as its electric distribution and transmission lines, is determined to be a cause of a fire. In such an event, the utility would be responsible for the costs of damages, including potential business interruption losses, and interest and attorneys fees, even if the utility has not been found negligent. The doctrine of inverse condemnation also is not exclusive of other theories of liability, including if the utility were found negligent, in which case additional liabilities, such as fire suppression, clean-up and evacuation costs, medical expenses, and personal injury, punitive and other damages, could be imposed. We are unable to predict the impact of the Wildfire Legislation on SDGEs ability to recover costs and expenses in the event that SDGEs equipment is determined to be a cause of a fire, and specifically in the context of the application of inverse condemnation. Cost Recovery Through Insurance or Rates As a result of the strict liability standard applied to electric IOU-caused wildfires in California, substantial losses recently recorded by insurance companies, and the risk of an increase in the number and size of wildfires, obtaining insurance coverage for wildfires that could be caused by SDGE (or, to a lesser extent, SoCalGas) has become increasingly difficult and costly. If these conditions continue or worsen, insurance for wildfire liabilities may become unavailable or may become prohibitively expensive and we may be challenged or unsuccessful when we seek recovery of insurance cost increases through the regulatory process. In addition, insurance for wildfire liabilities may not be sufficient to cover all losses we may incur, or it may not be available in sufficient amounts to meet the $1.0 billion of primary insurance required by the Wildfire Legislation. We are unable to predict whether we would be able to recover in rates or from the Wildfire Fund the amount of any uninsured losses. A loss that is not fully insured, is not sufficiently covered by the Wildfire Fund and/or cannot be recovered in customer rates could materially adversely affect Sempras and one or both of SDGEs and SoCalGas results of operations, financial condition, cash flows and/or prospects. 2022 Form 10-K | 46 Table of Contents Wildfire Mitigation Efforts Although we expend significant resources on measures designed to mitigate wildfire risks, these measures may not be effective in preventing wildfires or reducing our wildfire-related losses and their costs may not be fully recoverable in rates. SDGE is required by applicable California law to submit annual wildfire mitigation plans for approval by the OEIS and could be subject to increased risks if these plans are not approved in a timely manner or the measures set forth in the plans are not implemented effectively, as well as fines or penalties for any failure to comply with the approved plans. One of our wildfire mitigation and safety tools is to de-energize certain of our facilities when weather conditions become extreme and there is elevated wildfire ignition risk. These public safety power shutoffs have been subject to scrutiny by various stakeholders, including customers, regulators and lawmakers, which could increase the risk of liability for damages associated with these events. Such costs may not be recoverable in rates. Unrecoverable costs, adverse legislation or rulemaking, scrutiny by key stakeholders, ineffective wildfire mitigation measures or other negative effects associated with these efforts could materially adversely affect Sempras and SDGEs results of operations, financial condition, cash flows and/or prospects. The electricity industry is undergoing significant change, including increased deployment of DER, technological advancements, and political and regulatory developments . Electric utilities in California are experiencing increasing deployment of DER, such as solar generation, energy storage and energy efficiency and demand management technologies, and Californias environmental policy objectives are accelerating the pace and scope of these changes. This growth of DER and demand management will require further modernization of the electric distribution grid to, among other things, accommodate increasing two-way flows of electricity and increase the grids capacity to interconnect these resources. In addition, enabling Californias clean energy goals will require sustained investments in grid modernization, renewable integration projects, energy efficiency programs, energy storage options, operational and data management systems, and electric vehicle infrastructure. The growth of third-party energy storage alternatives and other technologies also may increasingly compete with SDGEs traditional transmission and distribution infrastructure in delivering electricity to consumers. The CPUC is conducting several proceedings regarding DER and demand management, including the evaluation of various projects and pilots; changes to the planning and operation of the electric distribution grid to prepare for higher penetration of DER; future grid modernization and grid investments; the deferral of traditional grid investments by DER; and the role of the electric distribution grid operator. These proceedings and the broader changes in Californias electricity industry could result in new regulations, policies and/or operational changes that could materially adversely affect SDGEs and Sempras results of operations, financial condition, cash flows and/or prospects. SDGE provides bundled electric procurement service through various resources that are typically procured on a long-term basis. Although SDGE currently provides such procurement service for a portion of its customer load, most customers receive procurement service from a load-serving entity other than SDGE through programs such as CCA and DA, in which case SDGE no longer procures energy for this departing load. CCA is only available if a customers local jurisdiction (city or county) offers such a program and DA is currently limited by a cap based on gigawatt hours. Several jurisdictions in SDGEs territory, including the City of San Diego, have implemented CCA, and additional jurisdictions are in the process of implementing or considering CCA. SDGEs historical energy procurement for future deliveries exceeds the needs of its remaining bundled customers as customers have elected CCA and DA services. To help achieve the goal of ratepayer indifference (as to whether or not customers energy is procured by SDGE or by CCA or DA), the CPUC revised the Power Charge Indifference Adjustment framework. The purpose of the framework is to help ensure SDGEs procurement cost obligations are more equitably shared among customers served by SDGE and customers now served by CCA and DA. SDGE implemented the framework on January 1, 2019. If the framework or other mechanisms designed to achieve ratepayer indifference do not perform as intended, if the law changes, or if the law is not interpreted or enforced as expected, SDGEs remaining bundled customers could experience large increases in rates for commodity costs under commitments made on behalf of CCA and DA customers prior to their departure or, if all such costs are not recoverable in rates, SDGE could experience material increases in its unrecoverable commodity costs. Any of these outcomes could have a material adverse effect on SDGEs and Sempras results of operations, financial condition, cash flows and/or prospects. Natural gas and natural gas storage have increasingly been the subject of political and public scrutiny, including a desire by some to reduce or eliminate reliance on natural gas as an energy source . Certain California legislators, as well as stakeholder, advocacy and activist groups, have expressed a desire to limit or eliminate reliance on natural gas as an energy source by advocating increased use of renewable electricity and electrification in lieu of the use of natural gas. Reducing methane emissions also has become a major focus of certain local and state agencies and the U.S. Administration, as well as the CPUC, resulting in passed or proposed legislation, regulation, policies and ordinances to prohibit or restrict the use and consumption of natural gas in new buildings, appliances and other applications. These actions could have the effect of reducing natural gas use over time. 2022 Form 10-K | 47 Table of Contents CARB, Californias primary regulator for GHG emissions reduction programs, continues to pursue plans for reducing GHG emissions in line with Californias climate goals that include proposals to reduce natural gas demand through proposed building decarbonization measures (for example, zero-emission standards for space and water heaters), or through promoting legislation for increased renewable electricity generation. Additionally, the CECs Title 24 requirements mandate that new construction include electric-ready buildings and heat pump technologies beginning in 2023. The CPUC has an ongoing proceeding that seeks to establish a state-wide process to help utilities plan appropriate gas infrastructure portfolios as natural gas usage in the state is expected to decline. This includes a new gas infrastructure General Order (GO 177) requiring site-specific approvals for certain gas infrastructure projects as well as issuance of a CPUC staff proposal to develop a gas distribution infrastructure decommissioning framework. The CPUC may similarly enact measures to reduce natural gas demand (such as more aggressive energy efficiency programs), promote fuel substitution (such as replacement of natural gas appliances with electric appliances), and order changes (such as its recent decision to eliminate gas line extension allowances for new applications submitted on or after July 1, 2023). A substantial reduction in or the elimination of natural gas as an energy source in California without adequate and appropriate recovery of investments could result in impairment of some or all of SoCalGas and SDGEs natural gas infrastructure assets if they were not permitted to be repurposed for alternative fuels, were required to be depreciated on an accelerated basis or were to become stranded, which could have a material adverse effect on SoCalGas, SDGEs and Sempras results of operations, financial conditions, cash flows and/or prospects. SDGE may incur significant costs and liabilities from its partial ownership of a nuclear facility being decommissioned . SDGE has a 20% ownership interest in SONGS, which we discuss in Note 15 of the Notes to Consolidated Financial Statements. SDGE and each of the other owners of SONGS is responsible for financing its share of the facilitys expenses and capital expenditures, including those related to decommissioning activities. Although the facility is being decommissioned, SDGEs ownership interest in SONGS continues to subject it to risks, including: the potential release of radioactive material the potential harmful effects from the former operation of the facility limitations on the insurance commercially available to cover losses associated with operating and decommissioning the facility uncertainties with respect to the technological and financial aspects of decommissioning the facility SDGE maintains the SONGS NDT to provide funds for nuclear decommissioning. Trust assets have been generally invested in equity and debt securities, which are subject to market fluctuations. A decline in the market value of trust assets, an adverse change in the law regarding funding requirements for decommissioning trusts, or changes in assumptions or forecasts related to decommissioning dates, technology and the cost of labor, materials and equipment due to inflationary pressures or otherwise could increase the funding requirements for these trusts, which costs may not be fully recoverable in rates. In addition, CPUC approval is required to make withdrawals from the NDT, and CPUC approval for certain expenditures may be denied if the CPUC determines the expenditures are unreasonable. In addition, decommissioning may be materially more expensive than we currently anticipate and therefore decommissioning costs may exceed the amounts in the NDT. Rate recovery for overruns would require CPUC approval, which may not occur. The occurrence of any of these events could result in a reduction in our expected recovery and have a material adverse effect on SDGEs and Sempras results of operations, financial condition, cash flows and/or prospects. Legal and Regulatory Risks SDGE and SoCalGas are subject to extensive regulation by federal, state and local legislative and regulatory authorities, which may materially adversely affect Sempra, SDGE and SoCalGas. Rates and Other Financial Matters The CPUC regulates SDGEs and SoCalGas customer rates, except for SDGEs electric transmission rates that are regulated by the FERC, and conditions of service. The CPUC also regulates SDGEs and SoCalGas sales of securities, rates of return, capital structure, rates of depreciation, long-term resource procurement and other financial matters in various ratemaking proceedings. The CPUC periodically approves SDGEs and SoCalGas customer rates based on authorized capital expenditures, operating costs, including income taxes, and an authorized rate of return on investments while incorporating a risk-based decision-making framework, as well as settlements with third parties. The outcome of ratemaking proceedings can be affected by various 2022 Form 10-K | 48 Table of Contents factors, many of which are not in our control, including the level of opposition by intervening parties; any rejection by the CPUC of settlements with third parties; potential rate impacts; increasing levels of regulatory review; changes in the political, regulatory, or legislative environments; and the opinions of regulators, consumer and other stakeholder groups and customers. These ratemaking proceedings include decisions about major programs in which SDGE and SoCalGas make investments under an approved CPUC framework, such as wildfire mitigation and pipeline and storage integrity and safety enhancement programs, but which investments may remain subject to a CPUC filing or reasonableness review with potentially unclear standards or other factors as described above that may result in the disallowance of incurred costs. SDGE and SoCalGas also may be required to incur costs and make investments to comply with proposed legislative and regulatory requirements and initiatives, including those related to Californias climate goals and policies, and their ability to recover these costs and investments may depend on the final form of the legislative or regulatory requirements and the ratemaking mechanisms associated with them. Recovery can also be affected by the timing and process of the ratemaking mechanism, in which there can be a significant time lag between when costs are incurred and when those costs are recovered in customers rates and material differences between the forecasted and authorized costs embedded in rates (which are set on a prospective basis) and the actual costs incurred. The CPUC may also experience delays in its decisions on recovery or may deny recovery altogether on the basis that costs were not reasonably or prudently incurred or for other reasons. Even if recoverable, the cost of investments to support the clean energy transition in California while also investing in necessary safety and reliability may negatively impact the affordability of SDGEs and SoCalGas customer rates and their and Sempras results of operations, financial condition, cash flows and/or prospects. In addition, a CPUC cost of capital proceeding every three years determines a utilitys authorized capital structure and authorized return on rate base, and the CCM applies in the interim years and considers changes in the cost of capital based on changes in interest rates for each 12-month period ending September 30 (the measurement period). Alternatively, each of SDGE and SoCalGas are permitted to file a cost of capital application in an interim year in which an extraordinary or catastrophic event materially impacts its cost of capital and affects utilities differently than the market as a whole to have its cost of capital determined in lieu of the CCM. Any such rate change due to a downward trigger of the CCM could have a material adverse effect on Sempras and the applicable utilitys results of operations, financial condition, cash flows and/or prospects. We discuss the CCM in Part I Item 1. Business - Ratemaking Mechanisms Sempra California Cost of Capital Proceedings, and in Note 4 of the Notes to Consolidated Financial Statements. The FERC regulates electric transmission rates, the transmission and wholesale sales of electricity in interstate commerce, transmission access, the rates of return on investments in electric transmission assets, and other similar matters involving SDGE. These ratemaking mechanisms are subject to many risks similar to those described above regarding the CPUC ratemaking proceedings. CPUC Authority Over Operational Matters The CPUC has regulatory authority related to safety standards and practices, competitive conditions, reliability and planning, affiliate relationships and a wide range of other operational matters, including citation programs concerning matters such as safety activity, disconnection and billing practices, resource adequacy and environmental compliance. Many of these standards and citation programs are becoming more stringent and could impose significant penalties, including enforcement programs under which the CPUC staff can issue citations that in some cases can impose substantial fines. The CPUC also continues to explore expansion of its programs to provide additional oversight. The CPUC conducts reviews and audits of the matters under its authority and could launch investigations or open proceedings at any time on any such matter it deems appropriate, the results of which could lead to citations, disallowances, fines and penalties, as well as corrective or mitigation actions required to address any noncompliance that may not be sufficiently funded by customer rates or at all. Any such occurrence could have a material adverse effect on Sempras, SDGEs and SoCalGas results of operations, financial condition, cash flows and/or prospects. We discuss various CPUC proceedings relating to SDGE and SoCalGas in Notes 4 and 16 of the Notes to Consolidated Financial Statements. Potential Regulatory Changes and Influence of Other Organizations SDGE, SoCalGas and Sempra may be materially adversely affected by revisions or reinterpretations of existing or new legislation, regulations, decisions, orders or interpretations of the CPUC, the FERC or other regulatory bodies, any of which could change how SDGE and SoCalGas operate, affect their ability to recover various costs through rates or adjustment mechanisms, require them to incur additional expenses or otherwise materially adversely affect their and Sempras results of operations, financial condition, cash flows and/or prospects. SDGE and SoCalGas are also affected by numerous advocacy groups, including California Public Advocates Office, The Utility Reform Network, Utility Consumers Action Network and the Sierra Club. Any success by any of these groups in directly or 2022 Form 10-K | 49 Table of Contents indirectly influencing regulatory bodies with authority over their operations could have a material adverse effect on SDGEs, SoCalGas and Sempras results of operations, financial condition, cash flows and/or prospects. SoCalGas has incurred and may continue to incur significant costs, expenses and other liabilities related to the Leak. From October 23, 2015 through February 11, 2016, SoCalGas experienced the Leak, which we describe in Note 16 of the Notes to Consolidated Financial Statements. Litigation In September 2021, SoCalGas and Sempra entered into an agreement with counsel to resolve lawsuits filed by approximately 36,000 plaintiffs (the Individual Plaintiffs) against SoCalGas and Sempra related to the Leak resulting in a payment of approximately $1.8 billion. The Individual Plaintiffs who do not participate in that settlement (the Remaining Individual

Plaintiffs) will be able to continue to pursue their claims. As of February 21, 2023, lawsuits filed by the Remaining Individual Plaintiffs and several shareholder derivative actions are pending against SoCalGas related to the Leak, some of which have also named Sempra and/or certain officers and directors of SoCalGas and Sempra. Additional litigation may be filed against us related to the Leak or our responses to it. The costs of defending against, settling or otherwise resolving the pending lawsuits or any new litigation could materially adversely affect SoCalGas and Sempras results of operations, financial condition, cash flows and/or prospects. We discuss these risks above under Risks Related to All Sempra Businesses Legal and Regulatory Risks and in this risk factor below under Estimated Costs, Insurance and Accounting and Other Impacts. Regulatory Proceedings SoCalGas has been subject to an OII to investigate and consider, among other things, what damages, fines or other penalties, if any, should be imposed against SoCalGas in connection with the Leak (the Leak OII). In October 2022, SoCalGas executed a settlement agreement with SED and the Public Advocates Office at the CPUC to resolve all aspects of the Leak OII, which is subject to CPUC approval. The settlement agreement provides for financial penalties, certain costs that SoCalGas will reimburse, a violation of California Public Utilities Code section 451, and costs previously incurred by SoCalGas for which it will not seek recovery from ratepayers, among other provisions. Other investigations related to the Leak could result in additional findings of violations of laws, orders, rules or regulations as well as fines and penalties, any of which could involve substantial costs and cause reputational damage. In addition, SoCalGas may incur higher operating costs and additional capital expenditures as a result of new investigations or new laws, orders, rules and regulations arising out of this incident, or our responses thereto, which may not be recoverable through insurance or in customer rates. The occurrence of any of these risks could materially adversely affect SoCalGas and Sempras results of operations, financial condition, cash flows and/or prospects. Natural Gas Storage Operations and Reliability In February 2017, the CPUC opened a proceeding pursuant to SB 380 OII to determine the feasibility of minimizing or eliminating the use of the Aliso Canyon natural gas storage facility while still maintaining energy and electric reliability for the region, including analyzing alternative means for meeting or avoiding the demand for the facilitys services if it were eliminated. If the Aliso Canyon natural gas storage facility were to be permanently closed or if future cash flows from its operation were otherwise insufficient to recover its carrying value, we may record an impairment of the facility, which could be material, incur materially higher than expected operating costs and/or be required to make material additional capital expenditures (any or all of which may not be recoverable in rates), and natural gas reliability and electric generation could be jeopardized. Any such outcome could have a material adverse effect on SoCalGas and Sempras results of operations, financial condition, cash flows and/or prospects. Cost Estimate, Insurance and Accounting and Other Impacts At December 31, 2022, SoCalGas estimates certain costs related to the Leak are $3,486 million (the cost estimate), including $1,279 million of costs recovered from insurance. Other than insurance for directors and officers liability, we have exhausted all of our insurance for this matter. We continue to pursue other sources of insurance coverage for costs related to this matter, but we may not be successful in obtaining additional insurance recovery for any of these costs. At December 31, 2022, $129 million of the cost estimate is accrued in Reserve for Aliso Canyon Costs and $4 million of the cost estimate is accrued in Deferred Credits and Other on SoCalGas and Sempras Consolidated Balance Sheets. The civil litigation that remains pending against us related to the Leak seeks compensatory, statutory and punitive damages, restitution, and civil and administrative fines, penalties and other costs. We also could be subject to damages, fines or other penalties as a result of the pending regulatory investigation related to the Leak. Except for the amounts paid or estimated to settle 2022 Form 10-K | 50 Table of Contents certain pending legal and regulatory matters as we describe in Note 16 of the Notes to Consolidated Financial Statements, the cost estimate does not include any amounts necessary to resolve pending litigation or regulatory proceedings, other potential litigation or other costs, in each case to the extent it is not possible to predict at this time the outcome of these actions or reasonably estimate the possible costs or a range of possible costs. Further, we are not able to reasonably estimate the possible loss or a range of possible losses in excess of the amounts accrued. The costs or losses not included in the cost estimate could be significant and could have a material adverse effect on SoCalGas and Sempras results of operations, financial condition, cash flows and/or prospects. Any failure by the CPUC to adequately reform SDGEs rate structure could have a material adverse effect on SDGE and Sempra. The NEM program is an electric billing tariff mechanism designed to promote the installation of on-site renewable generation (primarily solar installations) for residential and business customers. Depending on when the on-site generation was installed, NEM customers receive a full retail rate or a reduced retail rate for energy they generate but do not use that is fed to the utilitys power grid, which results in these customers not paying their proportionate share of the cost of maintaining and operating the electric transmission and distribution system, subject to certain exceptions, but still receiving electricity from the system when their self-generation is inadequate to meet their electricity needs. As more and higher electric-use customers switch to NEM and self-generate energy, the burden on remaining non-NEM customers, who effectively subsidize the unpaid NEM costs, increases, which in turn encourages more self-generation and further increases rate pressure on remaining non-NEM customers. The current electric residential rate structure in California is primarily based on consumption volume, which places a higher rate burden on customers with higher electric use while subsidizing lower-use customers. In August 2020, the CPUC initiated a rulemaking to further develop a successor to the existing NEM tariff. In November 2022, a previous proposed decision was withdrawn and a new proposed decision was issued, recommending substantial reform of the NEM program through the establishment of a new Net Billing Tariff that would apply to new net metered customers. The new Net Billing Tariff revises the current NEM structure for new customers with a retail export compensation rate that is better aligned with the value provided to the grid by behind-the-meter energy generation systems and retail import rates that encourage electrification and adoption of solar systems paired with storage. The new Net Billing Tariff is designed to compensate customers for the value of their exports to the grid based on avoided cost. In December 2022, the CPUC approved the new Net Billing Tariff for customers who interconnect their qualifying on-site renewable generation after April 14, 2023. Additionally, in response to California legislation adopted in 2022, the CPUC has initiated a rulemaking to broadly restructure the way fixed costs are collected, moving from volumetric charges to an income-graduated fixed charge for default residential rates by July 1, 2024. The intent of such a fixed charge would be to further help reduce cost shifts through an equitable approach to the distribution of electric costs. Depending on the effectiveness of the new Net Billing Tariff and any new rules related to fixed charges, which are uncertain, the risks associated with the existing NEM tariff could continue or increase. SDGE believes the establishment of a charge independent of consumption volume for residential customers is critical to help distribute rates among all customers that rely on the electric transmission and distribution system, including those participating in the NEM program. The absence of a charge independent of consumption volume coupled with the continuing increase of solar installation and other forms of self-generation, as well as the progression of DER and energy efficiency initiatives that could also reduce delivered volumes, could adversely impact electricity rates and the reliability of the electric transmission and distribution system. Any such impact could subject SDGE to increased customer dissatisfaction, increased likelihood of noncompliance with CPUC or other safety or operational standards and increased risks attendant to any such noncompliance, as we discuss above, as well as increased costs, including power procurement, operating and capital costs, and potential disallowance of recovery for these costs. If the CPUC does not continue to adequately reform SDGEs residential rate structure for all customers to better achieve reasonable, cost-based electric rates that are competitive with alternative sources of power and adequate to maintain the reliability of the electric transmission and distribution system, such failure could have a material adverse effect on SDGEs and Sempras results of operations, financial condition, cash flows and/or prospects. 2022 Form 10-K | 51 Table of Contents RISKS RELATED TO SEMPRA TEXAS UTILITIES Operational and Structural Risks Certain ring-fencing measures, governance mechanisms and commitments limit our ability to influence the management, operations and policies of Oncor. Various ring-fencing measures, governance mechanisms and commitments are in place that create legal and financial separation between Oncor Holdings, Oncor and their subsidiaries, on the one hand, and Sempra and its affiliates and subsidiaries, on the other hand. These measures are designed to enhance Oncors separateness from its owners and mitigate the risk that Oncor would be negatively impacted by a bankruptcy or other adverse financial development affecting its owners. These measures subject us and Oncor to various restrictions, including: seven members of Oncors 13-person board of directors must be independent directors in all material respects under the rules of the NYSE in relation to Sempra and its affiliates and any other owners of Oncor, and also must have no material relationship with Sempra or its affiliates or any other owners of Oncor currently or within the previous 10 years; of the six remaining directors, two must be designated by Sempra, two must be designated by Oncors minority owner, TTI, and two must be current or former Oncor officers Oncor will not pay dividends or other distributions (except for contractual tax payments) if (i) a majority of Oncors independent directors or any of the directors appointed by TTI determines that it is in the best interest of Oncor to retain such amounts to meet expected future requirements, (ii) the payment would cause Oncors debt-to-equity ratio to exceed the debt-to-equity ratio approved by the PUCT, or (iii) unless otherwise allowed by the PUCT, Oncors senior secured debt credit rating by any of the Rating Agencies falls below BBB (or Baa2 for Moodys) there must be certain separateness measures maintained to reinforce the legal and financial separation of Oncor from Sempra, including a requirement that dealings between Oncor and Sempra or Sempras affiliates (other than Oncor Holdings and its subsidiaries) must be on an arms-length basis, limitations on affiliate transactions and a prohibition on pledging Oncor assets or membership interests for any entity other than Oncor a majority of Oncors independent directors and the directors designated by TTI that are present and voting (with at least one required to be present and voting) must approve any annual or multi-year budget if the aggregate amount of capital expenditures or OM in the budget differs by more than 10% from the corresponding amounts in the budget for the preceding fiscal year or multi-year period, as applicable As a result of these measures, we do not control Oncor Holdings or Oncor, and we have limited ability to direct the management, policies and operations of Oncor Holdings and Oncor, including the deployment or disposition of their assets, declarations of dividends, strategic planning and other important matters. We have limited representation on the Oncor Holdings and Oncor boards of directors, which are each controlled by independent directors. Moreover, all directors of Oncor, including the directors we have appointed, have considerable autonomy and have a duty to act in the best interest of Oncor consistent with the approved ring-fence and Delaware law, which may in some cases be contrary to our interests. To the extent the directors approve or Oncor otherwise pursues actions that are not in our interest, our results of operations, financial condition, cash flows and/or prospects may be materially adversely affected. Industry-Related Risks Changes in the regulation or operation of the electric utility industry and/or the ERCOT market, as well as the outcome of regulatory proceedings, could materially adversely affect Oncor, which could materially adversely affect us. Oncor operates in the electric utility industry and, as a result, it is subject to many of the same or similar risks as Sempra California as we describe above under Risks Related to Sempra California, particularly with respect to regulation by federal, state, and local legislative and regulatory authorities regarding rates and other financial matters as well as operational matters. Oncor operates in the ERCOT market. In ERCOT, rates are set by the PUCT based on a historical test year, and as a result, the rates Oncor is allowed to charge generally will not exactly match its costs at any given point in time and there is no assurance that it will be able to earn its full return on invested capital. Further, the PUCT may not approve all items requested by Oncor in any rate proceeding, such as Oncors base rate review currently pending with the PUCT, including, among other things, recovery of all costs in rates, capital structure and authorized ROE. Failure to receive approval of its requests in any rate proceeding could adversely impact Oncor, which could adversely impact us, and those impacts could potentially be material. The costs and burdens associated with complying with the various legislative and regulatory requirements to which Oncor is subject at the federal, state, and local levels and adjusting Oncors business and operations in response to legislative and 2022 Form 10-K | 52 Table of Contents regulatory developments, including changes in ERCOT, and any fines or penalties that could result from any noncompliance, may have a material adverse effect on Oncor. In addition, any economic weakness in the ERCOT market or slowing growth in Oncors service territory could lead to reduced electricity demand, which could materially adversely affect Oncor. Moreover, legislative, regulatory, market or industry activities could adversely impact Oncors collections and cash flows and jeopardize the predictability of utility earnings. For instance, the PUCT has instituted various projects reviewing the regulatory framework regarding DER and other non-traditional technologies. As DER usage continues to grow, regulatory decisions made with respect to DER, including with respect to ERCOT market rules and transmission and distribution utilities ability to invest in non-traditional electricity delivery solutions, could adversely impact Oncors revenues and operations. If Oncor does not successfully respond to any legislative, regulatory, market or industry changes applicable to it, Oncor could suffer a deterioration in its results of operations, financial condition, cash flows and/or prospects, which could materially adversely affect our results of operations, financial condition, cash flows and/or prospects. Financial Risks Oncor could have liquidity needs that necessitate additional investments. Oncors business is capital-intensive, with significant capital spending expected in future periods, and it relies on external financing as a significant source of liquidity for its capital requirements. In the past, Oncor has financed much of its cash needs from operations and with proceeds from indebtedness, but these sources of capital may not be adequate or available on reasonable terms or at reasonable prices in the future. Because our commitments to the PUCT prohibit us from making loans to Oncor, we may elect to make capital contributions to Oncor if it fails to meet its capital requirements or is unable to access sufficient capital from other sources to finance its ongoing needs. Any such investments could be substantial, would reduce the cash available to us for other purposes, and could increase our indebtedness, any of which could materially adversely affect our results of operations, financial condition, cash flows and/or prospects. Sempra could incur substantial tax liabilities if EFHs 2016 spin-off of Vistra is deemed to be taxable. As part of its ongoing bankruptcy proceedings, in 2016, EFH distributed all the outstanding shares of common stock of its subsidiary Vistra Energy Corp. (formerly TCEH Corp. and referred to herein as Vistra) to certain creditors of TCEH LLC (the spin-off), and Vistra became an independent, publicly traded company. Vistras spin-off from EFH was intended to qualify for partially tax-free treatment to EFH and its shareholders under Sections 368(a)(1)(G), 355 and 356 of the U.S. Internal Revenue Code of 1986 (as amended) (collectively referred to as the Intended Tax Treatment). In connection with and as a condition to the spin-off, EFH received a private letter ruling from the IRS regarding certain issues relating to the Intended Tax Treatment, as well as tax opinions from counsel to EFH and Vistra regarding certain aspects of the spin-off not covered by the private letter ruling. In connection with the signing and closing of the merger of EFH (now Sempra Texas Holdings Corp. and a subsidiary of Sempra) with an indirect subsidiary of Sempra (the Merger), EFH sought and received a supplemental private letter ruling from the IRS and Sempra and EFH received tax opinions from their respective counsels that generally provide that the Merger will not affect the conclusions reached in, respectively, the IRS private letter ruling and tax opinions issued with respect to the spin-off described above. Similar to the IRS private letter ruling and opinions issued with respect to the spin-off, the supplemental private letter ruling is generally binding on the IRS and any opinions issued with respect to the Merger are based on factual representations and assumptions, as well as certain undertakings, made by Sempra and EFH. If such representations and assumptions are untrue or incomplete, any such undertakings are not complied with, or the facts upon which the IRS supplemental private letter ruling or tax opinions (which will not impact the IRS position on the transactions) are based are different from the actual facts relating to the Merger, the tax opinions and/or supplemental private letter ruling may not be valid and could be challenged by the IRS. Even though Sempra Texas Holdings Corp. would have administrative appeal rights if the IRS were to invalidate its private letter ruling and/or supplemental private letter ruling, including the right to challenge any adverse IRS position in court, any such appeal would be subject to uncertainties and could fail. If it is ultimately determined that the Merger caused the spin-off not to qualify for the Intended Tax Treatment, Sempra, through its ownership of Sempra Texas Holdings Corp., could incur substantial tax liabilities, which would materially reduce the value associated with our indirect investment in Oncor and could have a material adverse effect on our results of operations, financial condition, cash flows and/or prospects. 2022 Form 10-K | 53 Table of Contents RISKS RELATED TO SEMPRA INFRASTRUCTURE Operational Risks Project development activities may not be successful, projects under construction may not be completed on schedule or within budget, and completed projects may not operate at expected levels, any of which could materially adversely affect us. All Energy Infrastructure Projects We are involved in a number of energy infrastructure projects in various stages of development and construction, which subject us to numerous risks. Success in developing each project is contingent upon, among other things: our financial condition and cash flows and other factors that impact our ability to invest sufficient funds in the project, including for preliminary activities that may need to be accomplished before we can determine whether the project is feasible or economically attractive project assessment and design and our ability to foresee and incorporate new and developing trends and technologies in the energy industry, such as our pursuit of projects and design solutions to help enable our and our customers climate goals our ability to reach a final investment decision or meet other milestones, which may be influenced by external factors outside our control, including the global economy and energy and financial markets, actions by regulators, achieving necessary internal and external approvals from project partners (if applicable) and others, and many of the other factors described in this risk factor negotiation of satisfactory EPC agreements, including any renegotiation that may be required in the event of delays in final investment decisions or failures to meet other specified deadlines progressing relationships from MOUs, HOAs or similar arrangements, which are non-binding and generally do not impose obligations on any of the parties, to execution of definitive agreements and participation in the project identification of suitable partners, customers, suppliers and other necessary counterparties, negotiation of satisfactory equity, purchase, sale, supply, transportation and other appropriate commercial agreements, and satisfaction of any conditions to effectiveness of such agreements, including reaching a positive final investment decision within agreed timelines timely receipt and maintenance of required governmental permits, licenses and other authorizations that do not impose material conditions and are otherwise granted under terms we find reasonable our project partners, contractors and other counterparties willingness and financial or other ability to make their required investments or fulfill their contractual commitments on a timely basis timely, satisfactory and on-budget completion of construction, which could be negatively affected by engineering problems, work stoppages, unavailability or increased costs of materials, equipment, labor and commodities due to inflation or supply chain or other issues, contractor nonperformance and a variety of other factors, many of which we discuss above under Risks Related to All Sempra Businesses Operational Risks and elsewhere in this risk factor implementation of new or changes to existing laws or regulations that impact our infrastructure or the energy sector generally obtaining adequate and reasonably priced financing for the project, particularly in light of rising inflation and interest rates the absence of hidden defects or inherited environmental liabilities for the site of the project fast and cost-effective resolution of any litigation or unsettled property rights affecting the project geopolitical events and other uncertainties, such as the war in Ukraine Any failures with respect to the above factors or other factors material to any particular project could involve additional costs, otherwise negatively affect our ability to successfully complete the project and force us to impair or write off amounts we have invested in the project. If we are unable to complete a development project, if we experience delays, or if construction, financing or other project costs exceed our estimated budgets and we are required to make additional capital contributions, we may never recover or receive an adequate or any return on our investment and other resources expended on the project and our results of operations, financial condition, cash flows and/or prospects could be materially adversely affected. The operation of existing facilities and any future projects we are able to complete involves many risks, including the potential for unforeseen design flaws, engineering challenges, equipment failures or the breakdown for other reasons of facilities, equipment or processes; labor disputes; fuel interruption; environmental contamination; and the other operational risks that we discuss above under Risks Related to All Sempra Businesses Operational Risks. Any of these events could lead to our facilities being idle for an extended period of time or operating below expected levels, which may result in lost revenues or increased expenses, including higher maintenance costs and penalties. Any such occurrence could materially adversely affect our results of operations, financial condition, cash flows and/or prospects. 2022 Form 10-K | 54 Table of Contents LNG Export Projects In addition to the risks described above that are applicable to all our energy infrastructure projects, we are exposed to additional risks in connection with our LNG export projects, including the ECA LNG Phase 1 project under construction and our potential development of additional LNG export facilities. We discuss our LNG export projects in Part II Item 7. MDA Capital Resources and Liquidity Sempra Infrastructure. Each of these projects faces numerous risks. Our ability to reach a final investment decision for each project and, if a positive decision is made and a project is completed, the overall success of the project are dependent on global energy markets, including natural gas and oil supply, demand and pricing, the ability to reach advantageous agreements with our counterparties, including our partners, off-takers, and EPC contractors, risks inherent in construction, and the ability to obtain and maintain government approvals, among other things. In general, depressed natural gas and LNG prices in the markets we intend to serve due to shifts in supply or other factors could reduce the pricing and cost advantages of exporting domestically produced natural gas and LNG, which could lead to decreased demand. In addition, global oil prices and their associated current and forward projections could reduce demand for natural gas and LNG in some sectors. Although demand for natural gas is currently strong due to the geopolitical consequences of the war in Ukraine and increased recognition of the importance of energy security, a reduction in natural gas demand could also occur from higher penetration of alternative fuels in new power generation, or as a result of calls by some to limit or eliminate reliance on natural gas as an energy source globally. Oil prices could also make LNG projects in other parts of the world more feasible and competitive with LNG projects in North America, thus increasing supply and competition for any available LNG demand. Moreover, because LNG projects take a number of years to develop and construct, it is difficult to match current and expected demand with the projected supply from projects under development. Any of these occurrences could impact competition and prospects for developing LNG export projects and negatively affect the performance and prospects of any of our projects that are or become operational. Our projects may face distinct disadvantages relative to some LNG projects being pursued by other project developers, including: The proposed Cameron LNG Phase 2 project is subject to certain restrictions and conditions under the financing agreements for the Cameron LNG Phase 1 facility and requires unanimous consent of all JV members, including with respect to the equity investment obligations of each partner. We may not be able to satisfy these conditions and requirements, in which case our ability to develop the Cameron LNG Phase 2 project would be jeopardized. The ECA LNG projects under construction and in development are subject to ongoing land and permit disputes that could obstruct efforts to find or maintain suitable partners, customers and financing arrangements and hinder or halt construction and, if the projects are completed, operations. We discuss these risks below and under Risks Related to Sempra Infrastructure Legal Risks. In addition, the Mexican regulatory process and overlay of U.S. regulation for natural gas exports to LNG facilities in Mexico are not well developed, which, among other factors, contributed to delays obtaining a necessary permit from the Mexican government for the ECA LNG Phase 1 project and could cause similar delays or other hurdles in the future and lead to difficulties finding or maintaining suitable partners, customers and financing arrangements. We have entered into contracts with affiliates and third parties, subject to certain conditions, to supply and transport gas across the U.S.-Mexico border to meet the requirements of the ECA LNG Phase 1 project if and when it becomes operational. If affiliates or third parties experience delays or fail to obtain and maintain necessary permits and arrangements to provide such supply or transportation services or if we fail to maintain adequate gas supply and transportation agreements to support the project fully, it could cause additional costs or delays to the ECA LNG Phase 1 project. Finally, although we have planned measures to not disrupt operations at the ECA Regas Facility with the construction or operation of the ECA LNG Phase 1 project, these measures may not be effective. Moreover, we expect construction of the proposed ECA LNG Phase 2 project to conflict with ECA Regas Facility operations, making the decisions on whether, when and how to pursue the ECA LNG Phase 2 project dependent in part on whether the investment in this project would, over the long term, be more beneficial than continuing to provide regasification services under existing contracts for 100% of the ECA Regas Facilitys capacity through 2028. The PA LNG projects in development are to be located at a greenfield site and therefore are subject to disadvantages relative to projects being developed at brownfield sites, including increased time and costs to develop and construct the project. Development of these or any other LNG export projects will depend on the ability of our existing pipeline interconnections to be expanded or the ability to permit and construct new pipeline facilities, each of which may require us to enter into additional pipeline interconnection agreements with third-party pipelines. We and third parties may not be able to successfully develop and construct such new pipeline facilities, or we may not be able to secure such additional pipeline interconnections on commercially reasonable terms or at all. The capital requirements for LNG export projects that we decide to pursue can be significant, even if we ultimately decide not to make a positive final investment decision. In addition, our proposed facilities may not be completed in accordance with estimated timelines or budgets or at all as a result of the above or other factors, and delays, cost overruns or our inability to complete one or more of these projects could have a material adverse effect on our results of operations, financial condition, cash flows and/or prospects. Financing Arrangements We may become involved in various financing arrangements with respect to any of our energy infrastructure projects, such as guarantees, indemnities or loans. These arrangements could expose us to additional risks, including exposure to losses upon the occurrence of certain events related to the development, construction, operation or financing of the applicable projects that could have a material adverse effect on our future results of operations, financial condition, cash flows and/or prospects. We are dependent on the equipment provided by third parties to operate the Cameron LNG Phase 1 facility and the failure of such equipment may adversely impact our business and performance. Cameron LNG JV has experienced operating issues with equipment provided by third-party vendors, which have caused reductions in operating capacity and the declaration of force majeure events by Cameron LNG JV under its tolling agreements for its Cameron LNG Phase 1 facility. Certain of Cameron LNG JVs customers have raised objections regarding these force majeure declarations, and Cameron LNG JVs customers may raise objections in the future regarding these declarations or other force majeure declarations for similar operating issues. Cameron LNG JVs customers have obtained certain, and may in the future obtain additional, quantities of excess LNG production in connection with these and certain other force majeure events, and future force majeure events may also lead to the additional accrual of similar rights. The requirement to deliver excess LNG production to these customers in connection with these force majeure events has had, and in the future could have, an adverse impact on Sempra Infrastructures and our business and cash flows because Cameron LNG JV loses fees related to the excess production. These and other operational issues arising from equipment or facilities provided by third-party vendors may require us to undertake remediation, repair or equipment replacement activities that could result in reductions or cessations in production from our facilities. Although we are seeking to enforce warranty and other claims against our EPC contractors and other equipment vendors and suppliers, we may face challenges in successfully enforcing these claims against these third parties. Any such occurrence could have a material adverse effect on our results of operations, financial condition, cash flows and/or prospects. Fixed-price long-term contracts for services or commodities expose our businesses to inflationary pressures. Sempra Infrastructure seeks to secure long-term contracts for services and commodities in an effort to optimize the use of its facilities, reduce volatility in earnings and support the construction of new infrastructure. If these contracts are at fixed prices, their profitability may be negatively affected by inflationary pressures, including increased labor, materials, equipment, commodities and other operational costs, rising interest rates that affect financing costs and changes in applicable exchange rates. We may try to mitigate these risks by, among other things, using variable pricing tied to market indices, anticipating and providing for cost escalation when bidding on projects, contracting for direct pass-through of operating costs and/or entering into hedges. However, these measures may not fully or substantially offset any increases in operating expenses or financing costs caused by inflationary pressures and their use could introduce additional risks, any of which could have a material adverse effect on our results of operations, financial condition, cash flows and/or prospects. Increased competition could materially adversely affect us. The markets in which we operate are characterized by numerous strong and capable competitors, many of which have extensive and diversified development and/or operating experience domestically and internationally and financial resources similar to or greater than ours. In particular, the natural gas pipeline, storage and LNG market segments recently have been characterized by strong and increasing competition for winning new development projects and acquiring existing assets. In addition, our Mexican natural gas distribution business faces increased competition now that its former exclusivity period with respect to its distribution zones has expired and other distributors are legally permitted to build and operate natural gas distribution systems and compete to attract customers in the locations where it operates. These competitive factors could have a material adverse effect on our results of operations, financial condition, cash flows and/or prospects. We may not be able to enter into, maintain, extend or replace long-term supply, sales or capacity agreements. The ECA Regas Facility has long-term capacity agreements with a limited number of counterparties, and also may enter into short-term and/or long-term supply agreements to purchase LNG to be received, stored and regasified for sale to other parties. In addition, Cameron LNG JV has long-term liquefaction and regasification tolling agreements with three counterparties that collectively subscribe for the full nameplate capacity of the Cameron LNG Phase 1 facility. The long-term nature of these agreements and the small number of customers at each of these facilities exposes us to risks, including increased risk if these counterparties fail to meet their contractual obligations on a timely basis, increased credit risks, and risks associated with the long-term nature of our relationships with these counterparties, including increased impacts of disputes or other similar issues which we have experienced in the past. Any such issues that arise in the future with respect to our long-term contracts, including any that may be caused by or related to the war in Ukraine, could lead to significant legal and other costs, result in cancelation of certain key contracts or otherwise adversely affect our relationships with long-term customers, suppliers or partners, and could negatively   impact the reliability of revenues from the applicable projects and the prospects for any implicated development projects. Any such event could have a material adverse effect on our results of operations, financial condition, cash flows and/or prospects. Sempra Infrastructures ability to enter into new or replace existing long-term capacity agreements for its natural gas pipeline operations is dependent on, among other factors, demand for and supply of LNG and/or natural gas from its transportation customers, which may include our LNG export facilities. A decrease in demand for or supply of LNG or natural gas from such customers or the occurrence of other events that hinder Sempra Infrastructure from maintaining such agreements or establishing new ones could have a material adverse effect on our results of operations, financial condition, cash flows and/or prospects. The electric generation and wholesale power sales industries are highly competitive. As more plants are built, supplies of energy and related products may exceed demand, competitive pressures may increase and wholesale electricity prices may decline or become more volatile. Without long-term power sales agreements, our revenues may be subject to increased volatility, and we may be unable to sell the power that Sempra Infrastructures facilities are capable of producing or sell it at favorable prices, any of which could materially adversely affect our results of operations, financial condition, cash flows and/or prospects. We rely on transportation assets and services, much of which we do not own or control, to deliver natural gas and electricity. We depend on electric transmission lines, natural gas pipelines and other transportation facilities and services owned and operated by third parties to, among other things: deliver the natural gas, LNG, electricity and LPG we sell to customers or use for our LNG export facilities supply natural gas to our gas storage and electric generation facilities provide retail energy services to customers If transportation is disrupted, if the construction of new or modified interconnecting infrastructure is not completed on schedule or if capacity is inadequate, we may not be able to move forward with our projects on schedule, we may be unable to sell and deliver our commodities, electricity and other services to our customers, we may be responsible for damages incurred by these customers, such as the cost of acquiring alternative supplies at then-current spot market rates, and we could lose customers that may be difficult to replace in competitive market conditions. Any such occurrence could have a material adverse effect on our results of operations, financial condition, cash flows and/or prospects. Financial Risks Our international businesses and operations expose us to foreign currency and inflation risks. Our operations in Mexico pose foreign currency and inflation risks. Exchange and inflation rates with respect to the Mexican peso and fluctuations in those rates may have an impact on the revenue, costs and cash flows from our international operations, which could materially adversely affect our results of operations, financial condition, cash flows and/or prospects. We may attempt to hedge cross-currency transactions and earnings exposure through various means, including financial instruments and short-term investments, but these hedges may not fully achieve our objectives of mitigating earnings volatility that would otherwise occur due to exchange rate fluctuations. Because we do not hedge our net investments in foreign countries, we are susceptible to volatility in OCI caused by exchange rate fluctuations for entities whose functional currencies are not the U.S. dollar. Moreover, Mexico has experienced periods of high inflation and exchange rate instability in the past, and severe devaluation of the Mexican peso could result in governmental intervention to institute restrictive exchange control policies, as has occurred before in Mexico and other Latin American countries. We discuss our foreign currency exposure at our Mexican subsidiaries in Part II Item 7. MDA and Part II Item 7A. Quantitative and Qualitative Disclosures About Market Risk. Our businesses are exposed to market risks, including fluctuations in commodity prices, that could materially adversely affect us. We buy energy-related commodities from time to time for pipeline operations, LNG facilities or power plants to satisfy contractual obligations with customers. The regional and other markets in which we purchase these commodities are competitive and can be subject to significant pricing volatility as a result of many factors, including adverse weather conditions, supply and demand changes, availability of competitively priced alternative energy sources, commodity production levels and storage capacity, energy and environmental legislation and regulations, and economic and financial market conditions. Our results of operations, financial condition, cash flows and/or prospects could be materially adversely affected if the prevailing market prices for natural gas, LNG, electricity or other commodities we buy change in a direction or manner not anticipated and for which we have not provided adequately through purchase or sale commitments or other hedging transactions. Legal and Regulatory Risks Our international businesses and operations expose us to increased legal, regulatory, tax, economic, geopolitical and management oversight risks and challenges. Overview We own or have interests in a variety of energy infrastructure assets in Mexico, and we do business with companies based in foreign markets, including particularly our LNG export operations. Conducting these activities in foreign jurisdictions subjects us to complex management, security, political, legal, economic and financial risks that vary by country, many of which may differ from and potentially be greater than those associated with our wholly domestic businesses, and the occurrence of any of these risks could have a material adverse effect on our results of operations, financial condition, cash flows and/or prospects. These risks include the following and the other risks discussed in this risk factor below: compliance with tax, trade, environmental and other foreign laws and regulations, including legal limitations on ownership in some foreign countries and inadequate or inconsistent enforcement of regulations actions by local regulatory bodies, including setting rates and tariffs that may be earned by or charged to our businesses adverse changes in social, political, economic or market conditions or the stability of foreign governments adverse rulings by foreign courts or tribunals; challenges to or difficulty obtaining, maintaining and complying with permits or approvals; difficulty enforcing contractual and property rights; differing legal standards for lawsuits or other proceedings; and unsettled property rights and titles in Mexico expropriation or theft of assets with respect to our non-utility international business activities, changes in the priorities and budgets of international customers, which may be driven by many of the factors listed above, among others Mexican Government Influence on Economic and Energy Matters The Mexican government exercises significant and increasing influence over the Mexican economy and energy sector and has adopted or proposed additional changes that, in each case, could fundamentally impact private investment in this sector. Mexican governmental actions in the past several years in the electricity market include resolutions, orders, decrees, regulations and proposed and adopted amendments to Mexican law that could, among other things, threaten the prospects for private-party renewable energy generation in the country, limit the ability to dispatch renewable energy and receive or maintain operational permits, and increase costs of electricity for legacy renewables and cogeneration energy contract holders. The President of Mexico also proposed constitutional reform in September 2021 that would have eliminated the wholesale electricity market in Mexico and significantly limited the ability of private parties to participate in electricity generation. Although the proposed constitutional reform did not reach the two-third majority required for its approval and was therefore rejected by Mexicos Chamber of Deputies, other similar reforms to centralize and de-privatize the electricity market in Mexico could be proposed in the future. With respect to midstream and downstream activities, amendments to Mexicos Hydrocarbons Law that give SENER and the CRE additional powers to suspend and revoke permits became effective in May 2021. The amendments provide that suspension of permits will be determined by SENER or the CRE when a danger to national security, energy security, or the national economy is foreseen, and also provide new grounds for the revocation of permits under certain other circumstances related to a permit holders use of illegally imported products, failure to comply with provisions applicable to quantity, quality and measurement of products, or unauthorized modification of the technical condition of its infrastructure. Additionally, the amendments direct authorities to revoke permits that fail to comply with certain minimum storage and other requirements or violate provisions established by SENER or the amended Hydrocarbons Law, as applicable. We discuss these Mexican governmental actions in Note 16 of the Notes to Consolidated Financial Statements. We cannot predict whether proposed governmental actions will ultimately be passed or otherwise become effective in their current forms, nor can we predict the nature or level of their impact on the various segments of the energy sector in which we participate. We also cannot predict whether pending actions to enjoin enforcement or suspend or overturn existing laws and other governmental actions will be successful. More generally, we cannot predict the impact that the political, social and judicial landscape in Mexico will have on that countrys economy and energy sector and our business in Mexico. If any of the proposed governmental actions are passed or otherwise become effective, if efforts to enjoin enforcement or suspend or overturn adopted governmental actions fail, or if other similar moves by the Mexican government are taken to curb private-party participation in the energy sector, including through further amendments to Mexican laws, rules or the constitution or increased investigative and enforcement activities, it may impact our ability to operate our facilities at existing levels or at all, may result in increased costs for Sempra Infrastructure and its customers, may adversely affect our ability to develop new projects, may result in decreased revenues and cash flows, and may negatively impact our ability to recover the carrying values of our investments in Mexico, any of which may have a material adverse effect on our business, results of operations, financial condition, cash flows and/or prospects. U.S. and Mexican Laws and Foreign Policy, including Trade and Related Matters Our international business activities are subject to U.S. and Mexican laws and regulations related to foreign operations or doing business internationally, including the U.S. Foreign Corrupt Practices Act, the Mexican Federal Anticorruption Law in Public Contracting (Ley Federal Anticorrupcin en

Contrataciones Pblicas) and similar laws, and are sensitive to U.S. and Mexican foreign policy, trade policy and other geopolitical factors. The current and the last U.S. Administrations have taken different stances with respect to international trade agreements, tariffs, immigration policy and other matters of foreign policy that impact trade and foreign relations. Shifts in foreign policy could result in or increase adverse effects on our businesses and create uncertainty, making it difficult to predict the impact these policies could have on our businesses. Violations or alleged violations of the laws referred to above, as well as foreign policy positions that adversely affect imports and exports between the U.S., Mexican and other economies and foreign companies with whom we conduct business, could materially adversely affect our results of operations, financial condition, cash flows and/or prospects. Our businesses are subject to various legal actions challenging our property rights and permits, and our properties in Mexico could be subject to expropriation by the Mexican government. We are engaged in disputes regarding our title to the property in Mexico where our ECA Regas Facility is situated and our ECA LNG projects under construction and in development are expected to be situated, which we discuss in Note 16 of the Notes to Consolidated Financial Statements. In addition, we may have or seek to obtain long-term leases or rights-of-way from governmental agencies or other third parties to operate our energy infrastructure on land we do not own. In addition to the risks associated with such property ownership and use that we describe above under Risks Related to All Sempra Businesses Operational Risks, disputes regarding any of these properties could lead to difficulties finding or maintaining suitable partners, customers and project financing arrangements and could hinder or halt our ability to construct and, if completed, operate the affected facilities or proposed projects. Any of these outcomes could have a material adverse effect on our results of operations, financial condition, cash flows and/or prospects. Sempra Infrastructures energy infrastructure assets may be considered by the Mexican government to be a public service or essential for the provision of a public service, in which case these assets and the related businesses could be subject to expropriation or nationalization, loss of concessions, renegotiation or annulment of existing contracts, and other similar risks. Any such occurrence could materially adversely affect our results of operations, financial condition, cash flows and/or prospects. ##TABLE_START ##TABLE_ENDSUMMARY OF RISK FACTORS There are a number of risks you should understand before making an investment decision in our securities or the securities of our subsidiaries. This summary is not intended to be complete and should only be read together with the information set forth in Part I Item 1A. Risk Factors in this report. If any of these risks occurs, Sempras and its subsidiaries results of operations, financial condition, cash flows and/or prospects could be materially adversely affected, and the trading price of Sempras securities and those of its subsidiaries could decline. These risks include the following: Risks Related to Sempra Sempras cash flows, ability to pay dividends and ability to meet its debt obligations largely depend on the performance of its subsidiaries and entities accounted for as equity method investments The economic interest, voting rights and market value of our outstanding common and preferred stock may be adversely affected by any additional equity securities we may issue Risks Related to All Sempra Businesses Our businesses are subject to risks arising from their infrastructure and information systems Severe weather, natural disasters and other similar events could materially adversely affect us Our debt service obligations expose us to risks and could require additional equity securities issuances by Sempra and sales of equity interests in various subsidiaries or projects under development The availability and cost of debt or equity financing could be negatively affected by market and economic conditions and other factors, and any such effects could materially adversely affect us Credit rating agencies may downgrade our credit ratings or place those ratings on negative outlook Our businesses require numerous permits, licenses, franchises and other approvals from various governmental agencies, and the failure to obtain or maintain any of them, or lengthy delays in obtaining them, could materially adversely affect us Our businesses face climate change concerns and have environmental compliance and clean energy transition costs, which could have a material adverse effect on us Our businesses are subject to numerous governmental regulations and complex tax and accounting requirements and may be materially adversely affected by them or any changes to them Risks Related to Sempra California Wildfires in California pose risks to Sempra California (particularly SDGE) and Sempra The electricity industry is undergoing significant change, including increased deployment of DER, technological advancements, and political and regulatory developments Natural gas and natural gas storage have increasingly been the subject of political and public scrutiny, including a desire by some to reduce or eliminate reliance on natural gas as an energy source SDGE and SoCalGas are subject to extensive regulation by federal, state and local legislative and regulatory authorities, which may materially adversely affect Sempra, SDGE and SoCalGas Risks Related to Sempra Texas Utilities Certain ring-fencing measures, governance mechanisms and commitments limit our ability to influence the management, operations and policies of Oncor Changes in the regulation or operation of the electric utility industry and/or the ERCOT market, as well as the outcome of regulatory proceedings, could materially adversely affect Oncor, which could materially adversely affect us 2022 Form 10-K | 11 Table of Contents Risks Related to Sempra Infrastructure Project development activities may not be successful, projects under construction may not be completed on schedule or within budget, and completed projects may not operate at expected levels, any of which could materially adversely affect us We may not be able to enter into, maintain, extend or replace long-term supply, sales or capacity agreements Our international businesses and operations expose us to increased legal, regulatory, tax, economic, geopolitical and management oversight risks and challenges 2022 Form 10-K | 12 Table of Contents ##TABLE_START ##TABLE_ENDPART I.

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Item 1. Business General Development of Business SJW Group was initially incorporated as SJW Corp. in the state of California on February 8, 1985. SJW Group is a holding company with four wholly-owned subsidiaries: San Jose Water Company (SJWC) with its headquarters located at 110 West Taylor Street in San Jose, California 95110, was originally incorporated under the laws of the State of California in 1866. As part of a reorganization on February 8, 1985, SJWC became a wholly owned subsidiary of SJW Group. SJWC is a public utility in the business of providing water service in the metropolitan San Jose, California area. SJWNE LLC, a Delaware limited liability company, was formed in 2019, and is a wholly-owned subsidiary of SJW Group. SJWNE LLC is a special purpose entity established to hold SJW Groups investment in Connecticut Water Service, Inc. Connecticut Water Service, Inc. with its headquarters located in Clinton, Connecticut was incorporated in 1974 in the State of Connecticut. As part of the merger transaction between SJW Group and Connecticut Water Service, Inc. on October 9, 2019, Connecticut Water Service, Inc. and its subsidiaries (CTWS) became a wholly-owned subsidiary of SJWNE LLC. Connecticut Water Service, Inc. is a holding company with four wholly-owned subsidiaries. The Connecticut Water Company (Connecticut Water) and The Maine Water Company (Maine Water) are public utilities in the business of providing water service throughout Connecticut and Maine. The remaining two subsidiaries are Chester Realty, Inc., a real estate company in Connecticut, and New England Water Utility Services, Inc. (NEWUS), which provides contract water and sewer operations and other water related services. SJWTX, Inc. (SJWTX) was incorporated in the State of Texas in 2005. SJWTX is doing business as Canyon Lake Water Service Company. In 2022, SJWTX filed and was approved with the State of Texas an assumed named certificate to operate under the name The Texas Water Company. SJWTX is a public utility in the business of providing water service in the southern region of the Texas Hill Country in Bandera, Blanco, Comal, Hays, Kendall, Medina and Travis counties, the growing region between San Antonio and Austin, Texas. SJWTX has a 25% interest in Acequia Water Supply Corporation (Acequia). Acequia has been determined to be a variable interest entity within the scope of Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 810, Consolidation with SJWTX. as the primary beneficiary. As a result, Acequia has been consolidated with SJWTX. SJWTX is undergoing a corporate reorganization to separate regulated operations from non-tariffed activities. In 2021, SJWTX Holdings, Inc. (SJWTX Holdings) and Texas Water Operation Services LLC (TWOS) were formed for the purpose of effecting a corporate reorganization of our water services organization in Texas. TWOS was created for non-tariffed operations and is wholly-owned by SJWTX Holdings. SJWTX Holdings is a wholly-owned subsidiary of SJW Group, incorporated to hold the investments in SJWTX and TWOS. SJWTX Holdings intends to create a new subsidiary to hold future wholesale water supply assets in 2023. SJW Land Company was incorporated in 1985. SJW Land Company owns undeveloped land in California and Tennessee and operates commercial buildings in Tennessee. Together, SJWC, Connecticut Water, SJWTX, Maine Water and NEWUS, are referred to as Water Utility Services. SJW Land Company and Chester Realty, Inc. are collectively referred to as Real Estate Services. Regulation and Rates Water Utility Services, excluding non-tariffed activities, are subject to rate regulation based on cost recovery and meets the criteria of accounting guidance for rate-regulated operations, which considers the timing of the recognition of certain revenues and expenses. SJW Groups consolidated financial statements reflect the effects of the rate-making process. The rate-making process is intended to provide revenues sufficient to recover normal operating expenses, provide funds for replacement of water infrastructure and produce a fair and reasonable return on stockholder common equity. SJW Groups regulated operations financing activity is designed to achieve capital structures consistent with regulatory guidelines in the locations where the companies operate. The following summarizes each states authorized rates and capital structure as of December 31, 2022: ##TABLE_START California Connecticut Texas Maine (a) Authorized capital structure (debt/equity) 47% / 53% 47% / 53% 42% / 58% 50% / 50% Authorized return on equity 8.90% 9.00% 10.88% 9.70% Authorized rate base (in millions) $1,028.7 $580.9 $43.3 $129.6 Estimated rate base at year-end (in millions) (b) $1,074.9 $656.3 $92.0 $157.9 ##TABLE_END____________________________________ (a) Represents averages over water systems operating in the state. (b) An approximation of rate base which includes net utility plant not yet included in rate base pending rate case filings and outcomes. California Regulatory Affairs SJWCs rates, service and other matters affecting its business are subject to regulation by the California Public Utilities Commission (CPUC). Generally, there are three types of rate adjustments that affect SJWCs revenue collection: general rate adjustments, cost of capital adjustments, and offset rate adjustments. General rate adjustments are authorized in general rate case decisions, which usually authorize an initial rate adjustment followed by two annual escalation adjustments. General rate applications are normally filed and processed during the last year covered by the most recent general rate case as required by the CPUC in order to avoid any gaps in regulatory decisions on general rate adjustments. Actual revenue received may be higher or lower than the revenue requirement due to a number of factors including actual customer counts, usage or other regulatory factors in force at the time. Cost of capital adjustments are rate adjustments resulting from the CPUCs usual tri-annual establishment of a reasonable rate of return for SJWCs capital investments. The purpose of an offset rate adjustment is to compensate utilities for changes in specific pre-authorized offsettable capital investments or expenses, primarily for purchased water, groundwater extraction, purchased power and pensions. Pursuant to Section 792.5 of the California Public Utilities Code, a balancing account must be maintained for each expense item for which such revenue offsets have been authorized. Memorandum accounts track revenue impacts due to catastrophic events, certain unforeseen water quality expenses related to new federal and state water quality standards, energy efficiency, water conservation during periods of mandated water restrictions, water tariffs and other approved activities or as directed by the CPUC. The purpose of balancing and memorandum accounts is to track the under-collection or over-collection associated with such expense changes and activities for future recovery or refund considerations. Carrying balances of the balancing and memo accounts earn a rate of return based on treasury rates. On May 3, 2021, SJWC filed Application No. 21-05-004 requesting authority to adjust its cost of capital for the period from January 1, 2022 through December 31, 2024. The request seeks a revenue increase of $6.4 million or 1.61% in 2022. The application also proposes a rate of return of 8.11%, an increase from the current rate of 7.64%, a decrease in the average cost of debt rate from 6.20% to 5.48%, and a return of equity of 10.30%, an increase from the current rate of 8.90%. In addition, the request seeks to adjust SJWCs currently authorized capital structure of approximately 47% debt and 53% equity to approximately 45% debt and 55% equity. If approved, new rates are expected to be effective in the second quarter of 2023. On December 6, 2019, SJWC filed Application No. 19-12-002 to deploy Advanced Metering Infrastructure (AMI) throughout its service area. On August 5, 2021, an all-party settlement agreement was submitted to the CPUC for adoption that would authorize the deployment of AMI outside of the capital budget requested in the SJWCs General Rate Case Application No. 21-01-003 (2022 GRC). A final decision approving the settlement agreement was issued on June 10, 2022. SJWC filed Advice Letter No. 577 on May 24, 2022 to increase revenue requirement by $24.3 million or 5.9% to offset the increases to purchased potable water charges, the groundwater extraction fee, and purchased recycled water charges from its water wholesalers effective July 1, 2022. Advice Letter No. 577 was approved with an effective date of July 1, 2022. The CPUC approved the settlement of 2022 GRC on October 6, 2022 and issued Decision No. 22-10-005 (2022 GRC Decision) on October 11, 2022. SJWC received authority for an increase of revenue requirement by $25.1 million or 6.03% in 2022, $13.0 million or 2.94% in 2023, and $16.1 million or 3.56% in 2024. The application included requests to recover $18.2 million from balancing and memorandum accounts and authorization for a $350 million capital budget. Additionally, it further aligns authorized and actual consumption, particularly for business customers, addresses the water supply mix variability, and provides greater revenue recovery in the fixed charge. The approved revenue increase for 2022 is effective retrospectively to January 1, 2022. SJWC filed Advice Letter No. 581 on October 12, 2022 to recover $18.2 million in balancing and memorandum accounts in accordance with the 2022 GRC Decision. The advice letter was approved with an effective date of November 11, 2022. SJWC filed Advice Letter No. 582 on October 12, 2022 to refund $19.9 million accumulated in its Water Conservation Memorandum Account (WCMA) and its Water Conservation Expense Memorandum Account through August 31, 2022. This refund amount will offset the $18.2 million requested in Advice Letter No. 581 resulting in a net refund to customers of $1.7 million. Netting the two balances against each other allows for immediate recovery of the balancing and memorandum accounts and results in less confusion on customer bills. Advice Letter No. 582 was approved with an effective date of November 11, 2022. SJWC filed Advice Letter No. 583 on October 13, 2022 to increase revenue requirement by $25.1 million or 6.03% and implement new water rates in accordance with the 2022 GRC Decision. Advice Letter No. 583 was approved with an effective date of November 1, 2022. SJWC filed Advice Letter No. 585 on November 10, 2022 to recover $20.6 million in the Interim Rates Memorandum Account in accordance with the 2022 GRC Decision. Advice Letter 585 was approved with an effective date of January 1, 2023. SJWC filed Advice Letter No. 586 on November 18, 2022 to increase revenue requirement by $18.4 million or 4% for the escalation year increase in accordance with the 2022 GRC Decision. Advice Letter No. 586 was approved with an effective date of January 1, 2023. Connecticut Regulatory Affairs Connecticut Waters rates, service and other matters affecting its business are subject to regulation by the Public Utilities Regulatory Authority of Connecticut (PURA). PURA allows the Connecticut regulated operations to add surcharges to customers bills in order to recover certain costs associated with approved eligible capital projects through the Water Infrastructure Conservation Adjustment (WICA) in between full rate cases, as well as approved surcharges for the Water Revenue Adjustment (WRA). On October 26, 2021, Connecticut Water filed for a WICA increase of approximately $21.7 million in completed projects. Many of the projects were those that were not considered by PURA in the rate case because of the deadline in the proceeding for pro forma capital additions. On December 22, 2021, PURA approved a WICA surcharge of 2.44% to be added to bills of all Connecticut Water customers, including those of the former The Avon Water Company and The Heritage Village Water Company, effective January 1, 2022 which is expected to generate approximately $2.6 million in additional revenue. On February 14, 2022 Connecticut Water filed its 2021 WICA reconciliation with PURA. The reconciliation, approved by PURA on March 16, 2022 and effective for 12 months beginning April 1, 2022, replaced the expiring 2020 reconciliation surcharge of 0.07% with a credit of 0.02%. As a result, the net WICA surcharge, effective April 1, 2022 was 2.35%. On February 28, 2022, Connecticut Water filed its 2021 WRA. The mechanism reconciles 2021 revenues as authorized in the companys most recent rate cases. The 2021 WRA, as approved by PURA on March 30, 2022 and effective for 12 months beginning on April 1, 2022 imposed a 2.85% surcharge on customer bills to collect the 2021 revenue shortfall. On April 26, 2022, Connecticut Water filed for a WICA increase of $9.8 million in completed projects. PURA approved the Companys application on June 22, 2022. The cumulative WICA charge as of July 1, 2022 is 3.26%, collecting $3.5 million on an annual basis. On June 17, 2022, Connecticut Water submitted an application to PURA for the approval to issue unsecured notes in the amount of $25 million. A decision from PURA approving the application was received on August 10, 2022. The notes carry an interest rate of 4.71% and the closing occurred on December 14, 2022. On January 26, 2023, Connecticut Water filed with PURA for a $3.1 million increase in annualized revenues for approximately $27.8 million in projects completed through the WICA. Any PURA authorized increase is expected to be effective on April 1, 2023. Texas Regulatory Affairs SJWTXs rates are subject to the economic regulation of the Public Utilities Commission of Texas (PUCT). The PUCT may authorize rate increases after the filing of an Application for a Rate/Tariff Change. Rate cases may be filed as they become necessary, provided there is no current rate case outstanding. Furthermore, rate cases may not be filed more frequently than once every 12 months. SJWTX has no current general rate case pending. However, SJWTX filed its application to establish a System Improvement Charge (SIC) with the PUCT on December 30, 2022. This filing will allow SJWTX to add certain utility plant additions made since 2020 to its rate base, thereby increasing revenue and avoiding the immediate need for a general rate case. The SIC is projected to increase SJWTXs water revenue by $1.6 million and sewer revenue by $29 thousand within one year of the approval from the PUCT. Once the PUCT files the final order approving the SIC, SJWTX will be required to file a general rate case within four years. The decision on the SIC filing is expected to be in the third quarter of 2023. Notwithstanding the SIC filing, SJWTX will continue to file its annual adjustments for the Water Pass-through Charges (WPC) for Canyon Lake, Deer Creek, and Kendall West customers. All water supply cost increases are recoverable when the next annual WPC adjustment for each system is filed. Maine Regulatory Affairs Maine Waters rates, service and other matters affecting its business are subject to regulation by the Maine Public Utilities Commission (MPUC). MPUC approves rates on a division-by-division basis in Maine and allows Maine Water to add surcharges to customers bills in order to recover certain costs associated with capital projects through the Water Infrastructure Surcharge (WISC) in between general rate cases. Projects eligible for WISC surcharges include all infrastructure replacement or repair projects, excluding meters, that are necessary for the transmission, distribution or treatment of water. MPUC is authorized to allow a WRA mechanism to regulated water utilities. Maines rate-adjustment mechanism could provide revenue stabilization in divisions with declining water consumption and Maine Water expects to request usage of this mechanism in future rate filings when consumption trends support its use. On February 28, 2022, Maine Water filed requests for general rate increases in the Camden-Rockland, Freeport, Millinocket and Oakland Divisions. The four filings collectively request $0.5 million in new revenue and seek to reset the WISC in all four divisions. The four cases, while docketed separately, are proceeding through the adjudication process together. On February 2, 2023, Maine Water Company received final decisions from the MPUC on four general rate cases filed in 2022. The rate increases are retroactively effective for January 1, 2023, and authorize a $0.7 million increase in annual revenues. Please also see Item 1A , Risk Factors, Item 7 , Managements Discussion and Analysis of Financial Condition and Results of Operations, and Note 3 of Notes to Consolidated Financial Statements. Description of Business General The principal business of Water Utility Services consists of the production, purchase, storage, purification, distribution, wholesale and retail sale of water and wastewater services. SJWC provides water services to approximately 232,000 connections that serve approximately one million people over 139 square miles residing in portions of the cities of San Jose and Cupertino and in the cities of Campbell, Monte Sereno, Saratoga and in the Town of Los Gatos, and adjacent unincorporated territories, all in the County of Santa Clara in the State of California. The CTWS companies provide water service to approximately 141,000 service connections that serve a population of approximately 459,000 people in 81 municipalities with a service area of approximately 270 square miles throughout Connecticut and Maine and 3,000 wastewater connections in Southbury, Connecticut. SJWTX provides water service to approximately 26,000 service connections that serve approximately 77,000 people in a service area comprising more than 268 square miles in the region between San Antonio and Austin, Texas and approximately 900 wastewater connections. Together, the Water Utility Services distribute water to customers in their respective service areas in accordance with accepted water utility methods. SJWC, Connecticut Water and Maine Water provide non-tariffed services under agreements with municipalities and other utilities. These non-tariffed services include water system operations, maintenance agreements and antenna site leases. In addition, in October 1997, SJWC commenced operation of the City of Cupertino municipal water system under a 25-year lease which was due to expire in September of 2022 and was amended on January 8, 2020. The system is adjacent to the SJWC service area and has approximately 4,600 service connections. Under the terms of the lease, SJWC assumed responsibility for all maintenance and operating costs of the system, while receiving all payments for water service. SJWC paid an upfront $6.8 million concession fee and an additional $5.0 million in capital improvements to the City of Cupertino. On February 25, 2022, SJWC received a letter from the City of Cupertino exercising their option to extend the term of the lease an additional two years through October 1, 2024. SJWC paid an additional $1.6 million concession fee. The total concession fees paid for the agreement are being amortized over the contract term including the extension. CTWS provides contracted services to water utilities, as well as offers Linebacker protection plans for public drinking water customers in the States of Connecticut and Maine. Linebacker plans cover a limited amount of the cost of repairs to water and wastewater service lines and in-home plumbing. Services provided are dependent on the selected plan. SJW Land Company owns undeveloped real estate property in California and Tennessee, as well as commercial and warehouse properties in Tennessee. Chester Realty, Inc. owns commercial properties and parcels of land in Connecticut. Among other things, operating results from the water business fluctuate according to the demand for water, which is often influenced by seasonal conditions, such as impact of drought, summer temperatures or the amount and timing of precipitation in Water Utility Services service areas. Revenue, production expenses and income are affected by changes in water sales and the sources of water supply. Overhead costs, such as payroll and benefits, depreciation, interest on long-term debt, and property taxes are not significantly impacted by seasonality or water supply mix. As a result, earnings are highest in the higher demand, warm summer months and lowest in the lower demand, cool winter months. Water Supply California Water Supply SJWCs water supply consists of groundwater from wells, surface water from watershed run-off and diversion, reclaimed water, and imported water purchased from Santa Clara Valley Water District (Valley Water) under the terms of a master contract with Valley Water expiring in 2051. During normal rainfall years, purchased water provides approximately 40% to 50% of SJWCs annual production. An additional 40% to 50% of its water supply is pumped from the underground basin which is subject to a groundwater extraction charge paid to Valley Water. Surface supply, which during a normal rainfall year satisfies about 6% to 8% of SJWCs annual water supply needs, provides approximately 1% of its water supply in a dry year and approximately 14% in a wet year. In dry years, the decrease in water from surface run-off and diversion and the corresponding increase in purchased and pumped water increases production expenses substantially. The pumps and motors at SJWCs groundwater production facilities are propelled by electric power. SJWC has installed standby power generators at 38 of its strategic water production sites and manages a fleet of 21 portable generators deployed throughout the distribution system for power outages at remaining pumping facilities. In addition, the commercial office and operations control centers are outfitted with standby power equipment that allow critical distribution and customer service operations to continue during a power outage. Valley Water has informed SJWC that its filter plants, which deliver purchased water to SJWC, are also equipped with standby generators. In the event of a power outage, SJWC believes it will be able to prevent an interruption of service to customers for a limited period by pumping water using generator power and by using purchased water from Valley Water. In 2022, the level of water in the Santa Clara Valley groundwater basin, which is managed by the Valley Water, experienced an increase in most areas due to seasonal recovery, an increase in managed recharge operations, and a decrease in groundwater pumping by various water retailers in the region. As reported by Valley Water at the end of 2022, the groundwater level in the Santa Clara Plain was 14 feet higher compared to the same time in 2021. The total groundwater storage at the end of 2022 was within Stage 1 (Normal) of the Valley Waters Water Shortage Contingency Plan. On January 1, 2023, Valley Waters 10 reservoirs were 32% of capacity with 17,263 million gallons of water in storage. As of December 31, 2022, SJWCs Lake Elsman was 45.5% of capacity with 912 million gallons of water, approximately 113.9% of the five-year seasonal average. In addition, the rainfall at SJWCs Lake Elsman was measured at 29.45 inches for the period from July 1, 2022 through December 31, 2022, which is 207.4% of the five-year average. Subsequent to December 31, 2022, California has continued to experience wet weather patterns. SJWCs Montevina Water Treatment Plant treated 1,883 million gallons of water in 2022, which is 103.5% of the five-year average. SJWCs Saratoga Water Treatment Plant treated 42.7 million gallons of water in 2022, which is 17.1% of the five-year average. SJWC believes that its various sources of water supply will be sufficient to meet customer demand in 2023. On June 9, 2021, Valley Water declared a water shortage emergency and asked its retailers to reduce consumption by 15% based on 2019 usage. In response to Valley Waters declaration of drought emergency and call for conservation, SJWC filed with the CPUC to activate Stage 3 of its Rule 14.1 Water Shortage Contingency Plan. The current restrictions center on outdoor water usage which typically accounts for half of a residential customers consumption. The restrictions include limits on watering days and times, use of potable water for washing structures and other non-porous surfaces except to protect public health and safety, and no outdoor watering during and up to 48 hours after measurable rainfall. In addition, SJWC implemented a plan with CPUC that established budgets for each residential customer and places a surcharge on water usage that exceeds the allotted budget that was set based on a 15% reduction to 2019 usage. There is no such surcharge for commercial customers except for landscaping water usage. California also faces long-term water supply challenges. SJWC actively works with Valley Water to meet the challenges by continuing to educate customers on responsible water use practices and conducting long-range water supply planning. Connecticut Water Supply Connecticut Waters water sources vary among the individual systems, but overall approximately 80% of the total dependable yield comes from surface water supplies and 20% from wells. In addition, Connecticut Water has water supply agreements to supplement its water supply with the South Central Connecticut Regional Water Authority and The Metropolitan District that expire 2058 and 2053, respectively. Texas Water Supply SJWTXs water supply consists of groundwater from wells and purchased treated and raw water from the Guadalupe-Blanco River Authority (GBRA). SJWTX has long-term agreements with the GBRA, which expire in 2037, 2040, 2044 and 2050, respectively. The agreements, which are take-or-pay contracts, provide SJWTX with an aggregate of 7,650 acre-feet of water per year from Canyon Lake at prices that may be adjusted periodically by GBRA. SJWTX also has raw water supply agreements with the Lower Colorado River Authority (LCRA) and West Travis Public Utility Agency (WTPUA) expiring in 2059 and 2046, respectively, to provide for 350 acre-feet of water per year from Lake Austin and the Colorado River, respectively, at prices that may be adjusted periodically by the agencies. Maine Water Supply Water sources at Maine Water vary among the individual systems, but overall approximately 90% of the total dependable yield comes from surface water supplies and 10% from wells. Maine Water has a water supply agreement with the Kennebec Water District expiring in 2040. Maine Water relies on legislatively granted water rights in order to serve customers. In some instances, these rights were granted to predecessor water companies specially chartered by the Maine legislature many decades ago, with those entities later having been merged into Maine Water. The legislation incorporating these predecessor water companies did not address whether chartered rights may be transferred to another entity without special legislative action. The Maine Business Corporation Act generally provides that property and contract rights of a merged corporation are vested in the surviving corporation without reversion or impairment. In the MPUC proceedings that approved the mergers of these Maine Water predecessor companies, the survivorship of water rights was not contested. Please also see further discussion under Item 1A , Risk Factors and Item 7 , Managements Discussion and Analysis of Financial Condition and Results of Operations. Franchises Franchises granted by local jurisdictions permit Water Utility Services to construct, maintain, and operate water distribution systems within the streets and other public properties of a given jurisdiction. SJWC holds the necessary franchises to provide water in portions of the cities of San Jose and Cupertino and in the cities of Campbell, Monte Sereno and Saratoga, the Town of Los Gatos and the unincorporated areas of Santa Clara County. None of the franchises have a termination date, other than the franchise for the unincorporated areas of Santa Clara County, which terminates in 2035. Connecticut Waters utility services hold the necessary franchises to provide water in portions of the towns of Ashford, Avon, Beacon Falls, Bethany, Bolton, Brooklyn, Burlington, Canton, Chester, Clinton, Colchester, Columbia, Coventry, Deep River, Durham, East Granby, East Haddam, East Hampton, East Windsor, Ellington, Enfield, Essex, Farmington, Griswold, Guilford, Haddam, Hebron, Killingly, Killingworth, Lebanon, Madison, Manchester, Mansfield, Marlborough, Middlebury, Naugatuck, Old Lyme, Old Saybrook, Oxford, Plainfield, Plymouth, Portland, Prospect, Simsbury, Somers, Southbury, South Windsor, Stafford, Stonington, Suffield, Thomaston, Thompson, Tolland, Vernon, Voluntown, Waterbury, Westbrook, Willington, Windsor Locks and Woodstock. Additionally, the Heritage Village Water division serves the Town of Southbury with wastewater services. None of the franchises of the Connecticut water utility services have a termination date. Maine Water holds franchises necessary to provide water services in the towns served which are Biddeford, Saco, Old Orchard Beach, Scarborough (Pine Point), Porter, Parsonsfield, Hiram, Freeport, Camden, Rockland, Rockport, Owls Head, Union, Thomaston, Warren, Bucksport, Skowhegan, Oakland, Hartland, Millinocket and Greenville. None of the franchises with Maine Water have a termination date. SJWTX holds the franchises necessary to provide water and wastewater services to the City of Bulverde and the City of Spring Branch, which terminate in 2029 and 2036, respectively. The unincorporated areas that SJWTX serves in Comal, Blanco, Bandera, Hays, Kendall, Medina and Travis Counties do not require water service providers to obtain franchises. Seasonal Factors Water sales are seasonal in nature and influenced by weather conditions. The timing of precipitation and climatic conditions can cause seasonal water consumption by customers to vary significantly. Demand for water is generally lower during the cooler and rainy winter months. Demand increases in the spring when the temperature rises and rain diminishes. Competition The regulated operations of Water Utility Services are public utilities regulated by the CPUC in California, PURA in Connecticut, PUCT in Texas and MPUC in Maine (collectively, the Regulators) and operate within service areas approved by the regulators. Statutory laws provide that no other investor-owned public utility may operate in the service area of another public utility of the same class (e.g., another water utility) without first obtaining from the regulator a certificate of public convenience and necessity or similar authorization. Past experience shows such a certificate will be issued only after demonstrating that service in such area is inadequate. California law also provides that whenever a public agency constructs facilities to extend utility service to the service area of a privately-owned public utility, like SJWC, such an act constitutes the taking of property and is conditioned upon payment of just compensation to the private utility. Under the California law, municipalities, water districts and other public agencies have been authorized to engage in the ownership and operation of water systems. Such agencies are empowered to condemn properties operated by privately-owned public utilities upon payment of just compensation and are further authorized to issue bonds (including revenue bonds) for the purpose of acquiring or constructing water systems. Under Connecticut law, any condemnation of water utility property by a municipality or any unit of state government requires the payment of just compensation for the taking. Further, any condemnation of utility land by a state department, institution or agency (including a municipality) requires the approval of the PURA. Under Texas law, municipalities, water districts and other public agencies are authorized to engage in the ownership and operation of water systems. Such entities are empowered to acquire property, whether public or private, real or personal, by the exercise of the right of eminent domain, which entails payment to the owner of just compensation for the property taken. However, under current case law those entities may not exercise that right of eminent domain to take the entire operation of an investor-owned utility. Under Maine law, municipalities-individually and collectively, consumer-owned and standard water districts, and other public agencies are authorized to engage in the ownership and operation of water systems. Such entities may acquire the real and personal property of a privately-owned water company, and take over the companys operations, by exercising the power of eminent domain. In such a taking, the acquiring entity must furnish the condemnee just compensation. To the companys knowledge, no municipality, water district or other public agency has any pending proceeding to condemn any part of its existing water systems. The company is also unaware of any eminent domain proceeding to take any of its property or operations. Environmental Matters Water Utility Services produce potable water and generates wastewater and hazardous wastes in accordance with all applicable county, state and federal environmental rules and regulations. Additionally, public utilities are subject to environmental regulation by various other state and local governmental authorities. Water Utility Services is currently in compliance with all of the United States Environmental Protection Agencys (the EPA) surface water treatment performance standards, drinking water standards for disinfection by-products and primary maximum contaminant levels. These standards have been adopted and are enforced by the California State Water Board, Division of Drinking Water, the Connecticut Department of Public Health, the Maine Department of Health and Human Services, and the Texas Commission on Environmental Quality for SJWC, Connecticut Water, Maine Water and SJWTX, respectively. Other state and local environmental regulations apply to our Water Utility Services operations and facilities. These regulations relate primarily to the handling, storage and disposal of hazardous materials and discharges to the environment, including wastewater operations in the States of Connecticut and Texas. In 2016, SJWC began performing hazardous materials site assessments and remediation prior to the construction phase of capital projects. The site assessments are performed to remove any legacy materials and to obtain site closures from the Santa Clara County Department of Environmental Health under its Voluntary Cleanup Program. Water Utility Services are currently in compliance with all state and local public health and environmental regulations applicable to their operations. Please also see Part II, Item 7 , Managements Discussion and Analysis of Financial Condition and Results of Operations. Human Capital Resources In order to continue to achieve SJW Groups mission of delivering life sustaining, high-quality water and exceptional service to families, businesses and communities, we are committed to attract, retain and develop the highest quality talent. We believe our employees are our most important asset. Throughout our organization, our employees embrace the companys values of teamwork and respect, straight talk and transparency, integrity and trust, and service and compassion in everything we do. Employees participate in semi-annual employee engagement and satisfaction surveys providing feedback that enables the Company to continually assess and implement initiatives to enhance employee satisfaction and retention. Through our board and its committees, we are empowered to address factors that impact our employee strategy and drive positive change in our company and our communities. Our human capital measures and objectives focus on providing a safe and productive work environment that has clear positive and ethical values; a culture that embraces diversity, respect and equity; jobs that offer fair wages as benchmarked to the markets that we live and work in; competitive wages and benefits; and training and development opportunities that support our employees to establish and succeed in meaningful careers at SJW Group. Basic Workforce Data As of December 31, 2022, SJW Group had 757 full-time employees, of whom 362 were SJWC employees, 230 were Connecticut Water employees, 87 were SJWTX employees, and 78 were Maine Water employees. At SJWC, 215 employees are members of unions. Employees working for Connecticut Water, Maine Water and SJWTX are not represented by unions. In December of 2022, SJWC proposed tentative three-year bargaining agreements with the International Union of Operating Engineers (OE), representing certain employees in the engineering department, and the Utility Workers of America (OWUA), representing the majority of all non-administrative employees at SJWC covering the period from January 1, 2023 through December 31, 2025. The agreements include a 6% wage increase in 2023, 3.5% in 2024 and 5.5% in 2025 for the union workers. Acceptance of the OE and the OWUA bargaining agreements are anticipated in the first quarter of 2023. Employee Safety and Pandemic Response Aiming for a zero-harm culture, our vision is to manage health and safety performance to become a leader in the water services industry. Protecting the health and safety of our employees is a top priority. Our employee health and safety programs, focus on four core elements: Safety Leadership: demonstrating management commitment and support, empowering local teams to be accountable for safety; Participation: involving every employee in all aspects of the safety program, connecting safety initiatives to serving employees, customers, shareholders, our communities and the environment; Hazard Identification and Control: inspecting workplaces, identifying hazards, implementing controls, and partnering with the front-line teams responsible for delivering reliable, clean, safe drinking water and service; and, Training: training employees on hazards and how to protect themselves. Incident and crisis management of both known and unknown threats to employee health and safety are anticipated and planned for by our safety team. Our 2022 Sustainability Plan and Supplemental Report, to be published in 2023, incorporates specific targets that set the trajectory of our safety program to ensure continuous improvement, including: Implement processes and systems to track, monitor, report and continually improve health and safety performance; Communicate the updated Health and Safety Policy to employees to promote compliance, consultation, and participation of workers on health and safety matters; and Strive for zero accidents and injuries. We have implemented several management systems to plan and respond to workplace safety and training as well as incidents such as pandemics, wildfires, earthquakes, cyber threats and extreme weather, among others. The goal is to safeguard our employees health and safety during local, national, or global incidents. Locally, workplace hazards are identified by onsite inspections and from near-miss investigations. More broadly, the team collaborates to anticipate and plan for external events such as pandemic or for extreme weather or other external events that could impact our operations. Proactive identification of hazards keeps us one step ahead of our constantly changing workplace conditions. During the COVID-19 pandemic, SJW Groups primary focus has always been to protect the health and safety of employees, customers and the community from the spread of the disease in the workplace, while continuing to deliver reliable, clean and safe drinking water and service. Beginning in March 2020, with additional COVID-19 protections in place, we paused all non-essential services for two months; transitioned our office employees to company-wide remote work; and dispatched field service employees from their homes to minimize transmission of the virus. As the pandemic and knowledge of the virus evolved, our safety, human resources and operations teams implemented additional guidance protocols with a focus on cleaning and disinfection of facilities, vehicles, and tools; implementing engineering and administrative controls such as social distancing; and wearing face coverings to limit the transmission of the virus. In response to various stay-at-home government orders, we implemented policies and procedures to provide the flexibility to employees who are able to work from home and support remote-working by upgrading technology infrastructure, enhancing IT capabilities and implementing processes to facilitate online and remote communications. In an effort to ensure the safety and protection of our workplace and those customers and vendors with whom we serve and work, SJW Group announced a universal vaccination requirement for all employees by January 17, 2022 for three of our operating utilities and by February 14, 2022 at SJWC. On January 22, 2022, SJWC received a letter from the National Labor Relations Board (NLRB) stating that it would investigate the allegations from the Utility Workers Union of America Local 259 (Local 259) that SJWC failed to bargain in good faith by imposing a COVID vaccine mandate and threatening to terminate noncompliant employees and for, otherwise, failing to bargain over its decision to impose the mandate. The NLRB issued a decision to defer the unfair labor practice charge which was appealed by Local 259. In final response, the NLRB General Counsel denied the appeal with the decision to defer the unfair labor practice charge to arbitration. We continue to actively monitor all evolving federal, state and local guidance from public health authorities to ensure that our measures are in compliance with such rules and regulations and are effective in the continually changing pandemic environment. Engagement and Satisfaction SJW Group has invested significantly in employee engagement and satisfaction in alignment with its values and five building blocks of Community, Customers, Employees, Environment and Shareholders. Employees across SJW Group identified and adopted four sets of core values to guide their work and interactions: integrity and trust, compassion and service, straight talk and transparency, and respect and teamwork. Our leadership employs a servant leadership model where all leaders are encouraged and expected to provide service to their people ensuring that they continue to grow and thrive in their profession, knowledge, and general well-being. Regular Straight Talk meetings, employee town halls and quarterly Leadership on Tap gatherings are held to continue to build and support our culture and values. Additionally, the Company provides ongoing opportunities for employee recognition from peers and leaders and also administers an employee engagement and satisfaction survey twice per year. Diversity and Inclusion SJW Group believes that a workplace supporting diversity and inclusion not only promotes equity, teamwork, productivity and collaboration among employees, but also enables us to provide the best services to our customers, communities, and partners and enhance value for our stockholders. We are committed to fostering and maintaining a culture of diversity and inclusion, and we have been tracking our workforce demographics to identify employee teams, geographies, or seniority levels where hiring of minorities or specific demographic representation needs to be addressed. In 2021, CEO Eric Thornburg signed on to the CEO Action for Diversity Inclusion CEO pledge, which outlines a specific set of actions the signatory CEOs will take to cultivate a trusting environment where all ideas are welcomed and employees feel comfortable and empowered to have discussions about diversity and inclusion. The Companys Diversity, Equity and Inclusion Council (the Council) is comprised of employee volunteers from all four subsidiaries representing the communities we serve. The Council has implemented several impactful initiatives in 2022, including ongoing education and communications utilizing numerous platforms, providing unconscious bias training, and creating opportunities for all employees to celebrate and support cultural days of personal significance in their communities. During the year ended December 31, 2022, our workforce comprised of: ##TABLE_START Percentage of Workforce Gender: Female 29 % Male 71 % Ethnicity: Hispanic or Latino 20 % Not Hispanic or Latino 80 % Race: White 62 % Asian 9 % 2 or More Races 4 % Black or African American 4 % American Indian or Alaska Native 1 % Native Hawaiian or Other Pacific Islander 1 % Other/Not Reported 19 % ##TABLE_ENDWe work to ensure training and development opportunities are available so that all employees can establish and succeed in meaningful careers at SJW Group. In addition, we currently comply with Californias board diversity legislation requiring a minimum number of female directors and directors from underrepresented communities on our board of directors. Community Involvement In support of our mission as trusted, passionate and socially responsible professionals, we are dedicated to the people and the environment of the communities where we live, work, and serve. SJW Group provides various opportunities for our employees to participate in outreach programs from free virtual education programs for adults, employee-led courses for elementary school aged children, winter coat donation drives, environmental cleanups, community events, and grant programs supporting schools and fire departments. In addition, each of our subsidiaries supports their communities through charitable donations or sponsorships with a focus on the communities served. SJWC and Connecticut Water also have matching donations for certain programs to further promote our employees involvement in their communities. In California, the SJWC Employees Community Fund is a 501(c)(3) charitable organization that uses funds from employee contributions and company matches to provide grants to non-profit organizations supported by our employees. Fair Wages and Competitive Benefits SJW Groups future success is largely dependent upon our ability to attract and retain highly-skilled and qualified employees. Our California and Connecticut subsidiaries operate in particularly competitive labor markets, we believe our compensation package and benefit programs allow us to recruit and retain talented and qualified personnel. Our compensation and benefits programs include: Fair employee wages as benchmarked to the markets that our employees live and work in that are consistent with employee roles and responsibilities, skill levels, experience, and knowledge; Engagement of nationally, recognized outside compensation and benefits consulting firms to independently evaluate the appropriateness and effectiveness of compensation for our executive and other officers and to provide benchmarks for executive compensation as compared to peer companies; Short-term incentive compensation for management level staff aligning with company financial and operational goals targeted to our stakeholders: customers, communities, employees and stockholders; Alignment with stockholder value by utilizing equity awards linked to investment performance over time, as well as certain absolute financial results; A comprehensive annual employee performance review process pursuant to which we determine and communicate to employees annual merit increases, promotions and other changes to responsibilities and duties; and Eligibility for all employees to participate in health insurance, dental, vision, cafeteria plans, life and disability/accident coverage, retirement plans and/or salary deferral plans, an Employee Stock Purchase Plan, paid and unpaid leaves, a commuter assistance program, professional education and training, and tuition assistance. Executive Officers of the Registrant The following table summarizes the name, age, offices held and business experience for each of our executive officers, as of February 24, 2023: ##TABLE_START Name Age Offices and Experience Willie Brown 55 SJW Group Vice President, General Counsel and Corporate Secretary. Mr. Brown serves as Vice President, General Counsel and Corporate Secretary of SJW Group and SJWC since June 1, 2021. Mr. Brown served as Corporate Secretary and Assistant General Counsel of SJW Group and SJWC since January 1, 2020. Since April 2018, Mr. Brown has served as counsel and Corporate Secretary of various subsidiaries of the Corporation. Since joining SJWC in 2008, Mr. Brown has held various legal positions of increasing scope and responsibly. Prior to joining SJWC, Mr. Brown was an associate at two Silicon Valley law firms and is a member of the State Bar of California. Andrew R. Gere 56 SJWCPresident. Mr. Gere serves as President since April 2016 and was Chief Operating Officer from April 2015 to December 2022. From 2013 to April 2015, Mr. Gere was Vice President of Operations. From 2008 to 2013, Mr. Gere was Chief of Operations. From 2006 to 2008, Mr. Gere was Director of Maintenance. From 2005 to 2006, Mr. Gere was Director of Operations and Water Quality. From 2003 to 2005, Mr. Gere was Manager of Operations and Water Quality. Mr. Gere has been with SJWC since 1995. From October 2019 to December 2020, Mr. Gere served as Chairman of the National Association of Water Companies. Bruce A. Hauk 52 SJW GroupChief Operating Officer. Mr. Hauk serves as the Chief Operating Officer of SJW Group, SJWC, CTWS, and SJWTX since January 2023 and was the Chief Corporate Development and Strategy Officer of SJW Group, SJWC, CTWS, and SJWTX from August 2022 to December 2022. Prior to joining the Company, Mr. Hauk was the President of NextEra Water from May 2021 to August 2022. Prior to joining NextEra, Mr. Hauk served in several roles at American Water Works Company, Inc. from May 2011 to March 2021, lastly serving as President of Regulated Operations and Military Services Group and then as Deputy Chief Operating Officer. Previously, Mr. Hauk served as Deputy Mayor/Chief Administrative Officer for the City of Westfield, Indiana and as Town Manager/Director of Public Works for the City of Westfield, Indiana. Kristen A. Johnson 57 SJW GroupSenior Vice President and Chief Administrative Officer. Ms. Johnson serves as Senior Vice President since November 2022 and Chief Administrative Officer of SJW Group and Senior Vice President of Administration for CTWS and its subsidiaries since November 2019. Previously, Ms. Johnson served as Director of Human Resources, Vice President of Human Resources and Vice President and Corporate Secretary of CTWS and its subsidiaries from 2007, 2008, and 2010, respectively. She served as the Corporate Secretary of The Maine Water Company until July 2020. Craig J. Patla 55 CTWSPresident. Mr. Patla serves as President of CTWS and its subsidiaries, except The Maine Water Company, since January 2023. From April 2014 to December 2022, Mr. Patla was Vice President of Service Delivery. From 2011 to 2014, Mr. Patla was Director of Service Delivery. From 2008 to 2011, Mr. Patla was Manager of Service Delivery. From 2004 to 2008, Mr. Patla was Region Manager. Mr. Patla joined CTWS in 1990 as an engineer. Eric W. Thornburg 62 SJW GroupPresident, Chief Executive Officer and Chair of the Board. Mr. Thornburg serves as President and Chief Executive Officer of SJW Group and SJW Land Company and Chief Executive Officer of SJWC and SJWTX since November 6, 2017. He has served as the Chair of the Board of Directors of SJW Group, SJWC, SJW Land Company and SJWTX since April 25, 2018 and Chair of the Board of Directors of SJWNE LLC, CTWS and its subsidiaries since October 9, 2019. Prior to joining SJW Group, Mr. Thornburg served as President and Chief Executive Officer of CTWS since 2006, and Chair of the Board of CTWS since 2007. Mr. Thornburg served as President of Missouri-American Water, a subsidiary of American Water Works Corporation from 2000 to 2004. From July 2004 to January 2006, he served as Central Region Vice President-External Affairs for American Water Works Corporation. Andrew F. Walters 52 SJW GroupChief Financial Officer and Treasurer. Mr. Walters serves as Chief Financial Officer and Treasurer of SJW Group, SJWC, SJW Land Company, and SJWTX since January 2022. Mr. Walters served as Chief Corporate Development Officer and Integration Executive of SJW Group from November 2019 until January 2022 and previously served as Chief Administrative Officer of SJWC since January 31, 2014. Mr. Walters is also currently the Vice President of Business Planning of CWC and CTWS as of November 7, 2019. Prior to joining SJWC in 2014, Mr. Walters was a managing director and a senior acquisitions officer in the Infrastructure Investments Group of JP Morgan Asset Management from January 2009 to June 2013. Prior to this, Mr. Walters served in the Investment Banking Division of Citigroup as managing director and head of infrastructure for the Americas and in other roles focused on mergers and acquisitions and capital raising for clients, since 1993. ##TABLE_ENDPrincipal Accounting Officer of the Registrant The following table summarizes the name, age, offices held and business experience for our principal accounting officer, as of February 24, 2023: ##TABLE_START Name Age Offices and

Experience Mohammed G. Zerhouni 47 SJW GroupSenior Vice President of Finance, Principal Accounting Officer. Mr. Zerhouni serves as Senior Vice President of Finance, Principal Accounting Officer of SJW Group, SJWC, SJWTX and CTWS since January 2023. Prior to joining SJW Group Mr. Zerhouni was the Chief Financial Officer of Veolia Utility Parent, Inc. (VUP) from October 2022 to January 2023 which is part of the North American business of Veolia Group, a rate-regulated water and wastewater company. Previously, Mr. Zerhouni was Vice President/Controller and Chief Accounting Officer of VUP from December 2018 to September 2022. Mr. Zerhouni served in various roles of increasing responsibility up to Senior Manager in the audit practice of PricewaterhouseCoopers LLP from December 2004 to December 2018. Mr. Zerhouni is a certified public accountant. ##TABLE_ENDAvailable Information SJW Groups Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q and Current Reports on Form 8-K, and amendments to these reports, are made available free of charge through SJW Groups website at http://www.sjwgroup.com , as soon as reasonably practicable, after SJW Group electronically files such material with, or furnishes such materials to, the SEC. The content of SJW Groups website is not incorporated by reference to or part of this report. You may obtain electronic copies of our reports filed with the SEC on the SEC website at http://www.sec.gov . Item 1A. Risk Factors Investors should carefully consider the following risk factors and warnings before making an investment decision. The risks described below are not the only ones facing SJW Group and its subsidiaries. Additional risks that SJW Group and its subsidiaries does not yet know of or that it currently thinks are immaterial may also impair its business operations. If any of the following risks actually occur, SJW Group and its subsidiaries business, operating results or financial condition could be materially affected. In such case, the trading price of SJW Groups common stock could decline and you may lose part or all of your investment. Investors should also refer to the other information set forth in this Annual Report on Form 10-K, including the consolidated financial statements and the notes thereto. Risks Relating To Regulatory and Legal Matters Our business is regulated and may be adversely affected by changes to the regulatory environment. Our Water Utility Services are regulated public utilities. The operating revenue of SJWC, Connecticut Water, SJWTX and Maine Water is generated primarily from the sale of water at rates authorized by t he CPUC, PURA, PUCT and MPUC (the Regulators). The Regulators set rates that are intended to provide revenues sufficient to recover normal operating expenses, provide funds for replacement of water infrastructure and produce a fair and reasonable return on stockholder common equity. Please refer to Part I, Item 1, Regulation and Rates for a discussion of the most recent regulatory proceedings affecting the rates of our regulated operations. Consequently, our revenue and operating results depend substantially upon the rates the Regulators authorize. In our applications for rate approvals, we rely upon estimates and forecasts to propose rates for approval by the Regulators. No assurance can be given that our estimates and forecasts will be accurate or that the Regulators will agree with our estimates and forecasts and approve our proposed rates. To the extent our authorized rates may be too low, revenues may be insufficient to cover Water Utility Services operating expenses, capital requirements and SJW Groups historical dividend rate. In addition, delays in approving rate increases may negatively affect our operating results and operating cash flows. In addition, policies and regulations promulgated by the Regulators govern the recovery of capital expenditures, the treatment of gains from the sale of real utility property, the offset of production and operating costs, the recovery of the cost of debt, the optimal equity structure, and the financial and operational flexibility to engage in non-tariffed operations. If the regulators implement policies and regulations that will not allow SJWC, Connecticut Water, SJWTX and Maine Water to accomplish some or all of the items listed above, Water Utility Services future operating results may be adversely affected. Further, from time to time, the commissioners at the Regulators may change. Such changes could lead to changes in policies and regulations and there can be no assurance that the resulting changes in policies and regulation, if any, will not adversely affect our operating results or financial condition. If the CPUC disagrees with our calculation of SJWCs memorandum and balancing accounts, we may be required to make adjustments that could adversely affect our results of operations. Under a 2007 Connecticut law, PURA authorizes regulated water companies to use a rate adjustment mechanism, known as WICA, for eligible projects completed and in service for the benefit of the customers. Maine legislature enacted a law that allows Maine Water expedited recovery of investments in water systems infrastructure replacement, both treatment and distribution, through WISC, similar to WICA in Connecticut. There is no guarantee that these regulatory authorities will approve our applications to recover all or a portion of our capital expenditure or infrastructure investment through such rate adjustment mechanisms, and their failure to do so will adversely affect our financial conditions and results of operations. Recovery of regulatory assets is subject to adjustment by regulatory agencies and could impact the operating results of Water Utility Services. Generally accepted accounting principles for water utilities include the recognition of regulatory assets and liabilities as permitted by FASB ASC Topic 980Regulated Operations. In accordance with ASC Topic 980, Water Utility Services record deferred costs and credits on the balance sheet as regulatory assets and liabilities when it is probable that these costs and credits will be recovered or refunded in the ratemaking process in a period different from when the costs and credits were incurred. Please refer to Note 3 of the Notes to Consolidated Financial Statements for a summary of net regulatory assets. If the assessment of the probability of recovery in the ratemaking process is incorrect and the applicable ratemaking body determines that a deferred cost is not recoverable through future rate increases, the regulatory assets would need to be adjusted, which could have an adverse effect on our results of operations and financial condition. Streamflow regulations in Connecticut could potentially impact our ability to serve our customers. In December 2011, regulations concerning the flow of water in Connecticuts rivers and streams were adopted. As promulgated, the regulations require that certain downstream releases be made from seven of Connecticut Waters eighteen active reservoirs no later than ten years following the adoption of stream classifications by the Department of Energy and Environmental Protection (DEEP). Currently, downstream releases are made at two locations. The next streamflow releases will be initiated by October 2024 and will affect two additional reservoirs. No groundwater supply wells are affected by the regulations. DEEP has finalized stream classifications in all areas of Connecticut where Connecticut Water maintains and operates sources of supply. The Company remains engaged in the process in order to minimize impact to our available water supply. Although modified from prior versions, the regulations still have the potential to lower our safe yield, raise our capital and operating expenses and adversely affect our revenues and earnings. Although costs associated with the regulations may be recovered in the form of higher rates and Connecticut law allows for a WICA surcharge to recover capital improvement costs necessary to achieve compliance with the regulations, there can be no assurance PURA would approve rate increases to enable us to recover all such costs and surcharges. Water Utility Services is subject to litigation risks concerning water quality and contamination. Although Water Utility Services is not a party to any environmental and product-related lawsuits, there is no guarantee that such lawsuits will not occur in the future. Any environmental or product-related lawsuit may require us to incur significant legal costs and we may not be able to recover the legal costs from ratepayers or other third parties. Although Water Utility Services has liability insurance coverage for bodily injury and property damage, pollution liability is excluded from this coverage and our excess liability coverage. Pollution liability coverage is in place for the majority of the SJW Group locations and operations, but is subject to exclusions and limitations. In addition, any complaints or lawsuits against us based on water quality and contamination may receive negative publicity that can damage our reputation and adversely affect our business and trading price of our common stock. Water Utility Services is subject to possible litigation or regulatory enforcement action concerning water discharges to Waters of the United States (WOTUS). Regulatory actions and fines related to discharges of water to WOTUS against other water utilities have increased in frequency in recent years. If Water Utility Services is subject to a litigation or regulatory enforcement action, it might incur significant costs in fines and restoration efforts, and it is uncertain whether Water Utility Services would be able to recover some or all of such costs from ratepayers or other third parties. In addition, any litigation or regulatory enforcement action against us regarding a water discharge and/or resulting environmental impact may receive negative publicity that can damage our reputation and adversely affect our business and the trading price of our common stock. New or more stringent environmental regulations could increase Water Utility Services operating costs and affect its business. Water Utility Services are subject to water quality and pollution control regulations issued by the EPA and environmental laws and regulations administered by the respective states and local regulatory agencies. New or more stringent environmental and water quality regulations could increase Water Utility Services water quality compliance costs, hamper Water Utility Services available water supplies, and increase future capital expenditures. Under the federal Safe Drinking

Water Act, Water Utility Services is subject to regulation by the EPA relating to the quality of water it sells and treatment techniques it uses to make the water potable. The EPA promulgates, from time to time, nationally applicable standards, including maximum contaminant levels for drinking water. Additional or more stringent requirements may be adopted by each state. There can be no assurance that Water Utility Services will be able to continue to comply with all water quality requirements. Water Utility Services has implemented monitoring activities and installed specific water treatment improvements in order to comply with existing maximum contaminant levels and plan for compliance with future drinking water regulations. However, the EPA and the respective state agencies have continuing authority to issue additional regulations under the Safe Drinking Water Act. New or more stringent environmental standards could be imposed that will raise Water Utility Services operating costs and capital expenditures, including requirements for increased monitoring, additional treatment of underground water supplies, fluoridation of all supplies, more stringent performance standards for treatment plants, additional procedures to further reduce levels of disinfection by-products, and more comprehensive measures to monitor, reduce or eliminate known or newly identified contaminants such as polyfluoroalkyl substances. There are currently limited regulatory mechanisms and procedures available to us for the recovery of such costs and there can be no assurance that such costs will be fully recovered and failure to do so may adversely affect our operating results. The impact of climate change and climate change laws and regulations have been passed and are being proposed that require compliance with greenhouse gas emissions standards, as well as other climate change initiatives, which could increase Water Utility Services operating costs and affect our business. Climate change is receiving ever increasing attention worldwide. Many scientists, legislators, and others attribute global warming to increased levels of greenhouse gases, including carbon dioxide. Climate change laws and regulations enacted and proposed limit greenhouse gases emissions from covered entities and require additional monitoring/reporting. We produce a corporate social responsibility report, which provides an overview of our energy usage and greenhouse emissions. At this time, the existing greenhouse gases laws and regulations are not expected to materially harm Water Utility Services operations or capital expenditures. While regulation on climate change could change in light of the current federal administrations agenda, the uncertainty of future climate change regulatory requirements still remains. We cannot predict the potential impact of future laws and regulations on our business, financial condition, or results of operations. Although these future expenditures and costs for regulatory compliance may be recovered in the form of higher rates, there can be no assurance that the various state utility commissions that govern our business would approve rate increases to enable us to recover such expenditures and costs. Climate change may also impact water supply. For example, severity of drought conditions may impact the availability of water to all Water Utility Services and rising sea levels may impact the availability of groundwater to Water Utility Services. We may be at risk for litigation under the principle of inverse condemnation for activities in the normal course of business which have a damaging effect on private property. Under the California legal doctrine of inverse condemnation, a public utility taking or damaging private property can be responsible to the property owners for compensation, even when damage occurs through no fault or negligence of the utility company and regardless of whether the damage could be foreseen. Based upon existing California case law, SJWC could be sued under the doctrine of inverse condemnation and held liable if its facilities, operations or property, such as mains, fire hydrants, power lines and other equipment, or wildfires in our Santa Cruz mountain watershed result in damage to private property. A court finding of inverse condemnation does not obligate the CPUC to allow SJWC to recover damage awards or pass on costs to ratepayers. Insurance coverage for inverse condemnation may not be available or may not be sufficient. SJWC s liquidity, earnings, and operations may be adversely affected if we are unable to recover the costs of paying claims for damages caused by the operation and maintenance of our property from customers or through insurance. Our water utility property and systems are subject to condemnation and other proceedings through eminent domain. State laws in jurisdictions where we operate, including California, Connecticut, Texas and Maine, allow municipalities, water districts and other public agencies to own and operate water systems. These agencies are empowered to condemn water systems or real property owned by privately owned public utilities in certain circumstances and in compliance with state and federal laws. In general, if a public agency exercises its eminent domain power to take possession of private property, the government is required to pay just compensation to owners of such property. In the event of eminent domain or condemnation proceedings against our water utility property or systems, we may incur substantial attorneys fees, consultant and expert fees and other costs in considering a challenge to such proceeding and/or its valuation for just compensation, as well as fees and costs in any subsequent litigation if necessary. If the public agency prevailed and acquired our utility property, we would no longer have access to the condemned property or water system, neither would we be entitled to any portion of revenue generated from the use of such asset going forward. Furthermore, if public agencies succeed in acquiring our assets, there is a risk that we will not receive adequate compensation for the assets taken or be able to recover all charges associated with the condemnation of such assets, which may adversely affect our business operations and financial conditions. Risks Relating To Business Operations Fluctuations in customer demand for water due to seasonality, restrictions of use, weather, and lifestyle can adversely affect operating results. Water Utility Services are seasonal, thus quarterly fluctuation in results of operations may be significant. Rainfall and other weather conditions also affect Water Utility Services. Water consumption typically increases during the third quarter of each year when weather tends to be warm and dry. In periods of drought, if customers are encouraged or required to conserve water due to a shortage of water supply or restriction of use, revenue tends to be lower. Similarly, in unusually wet periods, water supply tends to be higher and customer demand tends to be lower, again resulting in lower revenues.

Furthermore, certain lifestyle choices made by customers can affect demand for water. For example, a significant portion of residential water use is for outside irrigation of lawns and landscaping. If there is a decreased desire by customers to maintain landscaping for their homes or restrictions are placed on outside irrigation, residential water demand would decrease, which would result in lower revenues. Conservation efforts and construction codes, which require the use of low-flow plumbing fixtures, could diminish water consumption and result in reduced revenue. In addition, in time of drought, water conservation may become a regulatory requirement that impacts the water usage of our customers. On July 8, 2021, Governor Gavin Newsom issued a proclamation declaring a drought emergency in fifty California Counties, including Santa Clara County. SJWC has activated our Water Shortage Contingency Plan to achieve the 15% conservation target. On July 9, 2021 Valley Water, the water supply agency for Santa Clara County, declared a water shortage emergency and requested its retailers enact conservation measures to achieve a mandatory 15% reduction compared to 2019 water consumption. SJWC has activated our Water Shortage Contingency Plan to achieve the 15% conservation target. On January 4, 2022, the State Water Resource Control Board (State Water Board) adopted emergency water use regulations that prohibit certain outdoor wasteful water practices. SJWCs drought response through our Water Shortage Contingency Plan includes the same restrictions on wasteful water practices. On June 10, 2022, the State Water Boards Second Water Conservation Emergency Declaration of 2022 became effective. This declaration prohibits the use of potable water for irrigation of non-functional turf at commercial, industrial, and institutional properties. SJWC is currently collaborating with our wholesaler and utility peers to engage and inform customers. Both water conservation emergency declarations will remain in effect for one year. The implementation of mandatory or voluntary conservation measures during the current drought has resulted and is expected to result in lower water usage by our customers which may adversely affect our results of operation. If the current conservation measures continue, or if new measures are imposed in response to drought conditions in the future, we may experience fluctuations in the timing of or a reduction in customer revenue. Furthermore, the CPUC may approve memorandum accounts, such as a WCMA, to allow companies to recover revenue reductions due to water conservation activities and certain conservation related costs. However, collection of such memorandum accounts is subject to a review and approval process by CPUC, which can be lengthy, and there is no assurance that we will be able to recover in a timely manner all or some of the revenue and costs recorded in the memorandum accounts. When drought conditions ease and the California State Water Board and Valley Water no longer mandate water conservation, the company may no longer be allowed to recover revenue lost due to continued conservation activities under the WCMA account and would therefore be exposed to differences between actual and authorized usage. This could result in lower revenues. Similar to SJWC, Connecticut Water and Maine Water have also been impacted by increased water conservation, as well as the use of more efficient household fixtures and appliances among residential users. There has been a trend of declining per customer residential water usage in Connecticut and Maine over the last several years. CTWSs regulated businesses at Maine Water are heavily dependent on revenue generated from rates it charges to its residential customers for the volume of water they use. The rates Connecticut Water and Maine Water charge for its water is regulated by PURA in Connecticut and MPUC in Maine, and CTWSs water services subsidiaries may not unilaterally adjust their rates to reflect changes in demand. A declining volume of residential water usage may have a negative impact on our operating revenues in the future if regulators do not reflect usage declines in the rate setting design process. Although the legislatures in Maine and Connecticut have provided legislation for water utilities to implement revenue adjustment mechanisms to allow for recovery of authorized rates where conservation has occurred and consumption has declined and such a mechanism has been approved by PURA and implemented for Connecticut Water, this mechanism has yet to be implemented at Maine Water. A contamination event or other decline in source water quality could affect the water supply of Water Utility Services and therefore adversely affect our business and operating results. Water Utility Services is required under drinking water regulations to comply with water quality requirements. Through water quality compliance programs, Water Utility Services monitors for contamination and pollution of its sources of water. In addition, a watershed management program provides a proactive approach to minimize potential contamination activities. There can be no assurance that Water Utility Services will continue to comply fully with all applicable water quality requirements or detect contamination timely or at all. In addition, our facilities and infrastructure, including water towers, reservoirs and wells, may be subject to vandalism, break-ins or attacks, which may cause contamination or damage to our water supply. While we have taken measures to maintain physical security of our facilities, there is no guarantee that such measures will be effective to prevent such events. In the event a contamination is detected, Water Utility Services must either commence treatment to remove the contaminant or procure water from an alternative source. Either of these results may be costly, may increase future capital expenditures and there can be no assurance that the regulators would approve a rate increase to enable us to recover the costs arising from such remedies. In addition, we could be held liable for consequences arising from hazardous substances or contamination in our water supplies or other environmental damages and our reputation may be harmed by the public disclosures or media reports of these events. Our insurance policies may not cover or may not be sufficient to cover the costs of these claims. Operating under contract water and waste systems subject us to risks. Water Utility Services operates a number of water and wastewater systems under operation and maintenance contracts. Pursuant to these contracts, such systems are operated according to the standards set forth in the applicable contract, and it is generally the responsibility of the owner of the system to undertake capital improvements over which we may not have control. We may not be able to convince the owner to make needed improvements in order to maintain compliance with applicable regulations. Although violations and fines incurred by water and wastewater systems may be the responsibility of the owner of the system under these contracts, such non-compliance events may reflect poorly on us as the operator of the system and harm our reputation, and in some cases, may result in liability to the same extent as if we were the owner. Water Utility Services rely on information technology and systems that are key to business operations. A system malfunction, security breach, cyber-attacks or other disruptions could compromise our information and expose us to liability, which could adversely affect business operations. Information technology is key to the operation of the Water Utility Services, including but not limited to payroll, general ledger activities, outsourced bill preparation and remittance processing, providing customer service and the use of Supervisory Control and Data Acquisition systems to operate our distribution system. Among other things, system malfunctions, computer viruses and security breaches could prevent us from operating or monitoring our facilities, billing and collecting cash accurately and timely analysis of financial results. In addition, we collect, process, and store sensitive data from our customers and employees, including personally identifiable information, on our networks. Despite our security measures, our information technology and infrastructure may be vulnerable to attacks by hackers or breached due to employee error, malfeasance or other disruptions. Any such breach could compromise our networks and the information stored there could be accessed without our authorization, publicly disclosed, lost or stolen which could result in legal claims or proceedings, violation of privacy laws or damage to our reputation and customer relationships. Our profitability and cash flow could be affected negatively in the event these systems do not operate effectively or are breached. In addition, we may not be able to develop or acquire information technology that is competitive and responsive to the needs of our business, and we may lack sufficient resources to make the necessary upgrades or replacements of our outdated existing technology to allow us to continue to operate at our current level of efficiency. In addition, we must comply with privacy rights regulations such as The California Consumer Privacy Act (CCPA), a state statute that became effective January 1, 2020, which enhances the privacy rights and consumer protections for California residents. Among other things, the CCPA establishes statutory damages for victims of data security breaches, and provides additional rights for consumers to obtain their data from any business that has their personally identifying information. On January 1, 2023 the California Privacy Rights Act (CPRA) took effect. The CPRA amended the CCPA to create new rights for consumers and impose additional obligations on businesses. We will also be subject to Connecticuts Act Concerning Personal Data Privacy and Online Monitoring (the Connecticut Privacy Act), a similar law that takes effect July 1, 2023. Implementing regulations have not yet been finalized under the CPRA and no regulations are expected pursuant to the Connecticut Privacy Act, creating a significant amount of uncertainty. Despite our efforts to comply with these laws, we may fail to do so which may lead to investigations, claims, and proceedings by governmental entities and private parties, damages for breach, and cause us to incur other significant costs, penalties, and other liabilities, as well as harm to our reputation. A failure of our reservoirs, storage tanks, mains or distribution networks could result in losses and damages that may adversely affect our financial condition and reputation. We distribute water through an extensive network of mains and store water in reservoirs and storage tanks located across our service areas. The Water Utility Services distribution systems were constructed during the period from the early 1900s through today. A failure of major mains, reservoirs, or tanks could result in injuries and damage to residential and/or commercial property for which we may be responsible, in whole or in part. The failure of major mains, reservoirs or tanks may also result in the need to shut down some facilities or parts of our water distribution network in order to conduct repairs. Such failures and shutdowns may limit our ability to supply water in sufficient quantities to our customers and to meet the water delivery requirements prescribed by governmental regulators, which could adversely affect our financial condition, results of operations, cash flow, liquidity and reputation. We also own and operate numerous dams in California, Connecticut and Maine, and a failure of such dams could result in losses and damages that may adversely affect our financial condition and reputation. Any business interruption or other losses might not be covered by existing insurance policies or be recoverable in rates, and such losses may make it difficult for us to secure insurance in the future at acceptable rates. Our insurance policies may not cover or may not be sufficient to cover the costs of these claims. Our business and financial performance may be adversely affected by high inflation. Inflation has the potential to adversely affect our liquidity, business, financial condition and results of operations by increasing our overall cost structure, particularly if we are unable to achieve increases in the rates we charge our customers. There is no guarantee that any future rate increase requests will be approved and granted in a timely manner and/or will be sufficient to cover costs for the impact of high inflation. The existence of inflation in the economy has resulted in, and may continue to result in, higher interest rates and capital costs, shipping costs, supply shortages, increased costs of labor and other similar effects. As a result of inflation, we have experienced and may continue to experience, cost increases. Although we may take measures to mitigate the impact of this inflation, if these measures are not effective, our business, financial condition, results of operations and liquidity could be materially adversely affected. Even if such measures are effective, there could be a difference between the timing of when these beneficial actions impact our results of operations and when the cost of inflation is incurred. SJW Land Company and Chester Realty, Inc. have real estate holdings that are subject to various business and investment risks. SJW Land Company owns real estate in California and Tennessee, and Chester Realty, Inc. owns real estate in Connecticut. The risks of investing directly in real estate vary depending on the investment strategy and investment objective and include the following: Market and general economic risksreal estate investment is tied to overall domestic economic growth and, therefore, carries market risk which cannot be eliminated by diversification. Generally, all property types benefit from national economic growth, though the benefits range according to local factors, such as local supply and demand and job creation. Because real estate leases are typically staggered and last for multiple years, there is generally a delayed effect in the performance of real estate in relation to the overall economy. This delayed effect can insulate or deteriorate the financial impact to SJW Land Company and Chester Realty, Inc. in a downturn or an improved economic environment. Vacancy rates can climb and market rents can be impacted and weakened by general economic forces, therefore affecting income to SJW Land Company and Chester Realty, Inc. A decrease in the value of a real estate property or increase in vacancy could result in reduced future cash flows to amounts below the propertys current carrying value and could result in an impairment charge. The value of real estate can decrease materially due to a deflationary market, decline in rental income, market cycle of supply and demand, long lag time in real estate development, legislative and governmental actions, environmental concerns, increases in rates of returns demanded by investors, and fluctuation of interest rates, eroding any unrealized capital appreciation and, potentially, invested capital. The success of SJW Land Company and Chester Realty, Inc.s real estate investment strategy depend largely on ongoing local, state and federal land use development activities and regulations, future economic conditions, the development and fluctuations in the sale of the undeveloped properties, the ability to identify the developer/potential buyer of the available-for-sale real estate, the timing of the transaction, favorable tax law, and the ability to maintain and manage portfolio properties. There is no guarantee that we will be able to execute the strategy successfully and failure to do so may adversely affect our operating results and financial condition. Work stoppages and other labor relations matters could adversely affect our business and operating results. As of December 31, 2022, 215 of our 757 total employees were union members. Most of our unionized employees are represented by the OWUA, except certain employees in the engineering department who are represented by the OE. Only employees at SJWC are union members. The current three-year bargaining agreements expired on December 31, 2022 and a tentative agreement has been negotiated and will begin in 2023 for the upcoming period, 2023 through 2025. Acceptance of the OE and the OWUA bargaining agreements are anticipated in the first quarter of 2023. We may experience difficulties and delays in the collective bargaining process to reach suitable agreements with union employees, particularly in light of increasing healthcare and pension costs. In addition, changes in applicable law and regulations could have an adverse effect on managements negotiating position with the unions. Labor actions, work stoppages or the threat of work stoppages, and our failure to obtain favorable labor contract terms during future negotiations may adversely affect our business, financial condition, results of operations, cash flows and liquidity. If we fail to maintain safe work sites, we can be exposed to not only people impacts but also to financial losses such as penalties and other liabilities. Our safety record is critical to our reputation because our business operation involves inherently dangerous activities. We maintain health and safety standards to protect our employees, customers, vendors and the public. Although we intend to adhere to such health and safety standards and aim for zero injuries, it is difficult to avoid accidents at all times. Our business sites, including construction and maintenance sites, often place our employees and others in close proximity with large pieces of heavy equipment, moving vehicles, pressurized water, underground trenches and vaults, chemicals and other regulated materials. On many sites we are responsible for safety and, accordingly, must implement safety procedures. If we fail to implement such procedures or if the procedures we implement are ineffective or are not followed by our employees or others, or if accidents occur outside of our control, our employees and others may be injured or die. Unsafe work sites also have the potential to increase employee turnover and raise our operating costs. Any of the foregoing could result in financial losses, which could have a material adverse impact on our business, financial condition, results of operations and cash flows. In addition, our operations can involve the handling and storage of hazardous chemicals, which, if improperly handled, stored or disposed of, could subject us to penalties or other liabilities. We are also subject to regulations dealing with occupational health and safety. Although we maintain functional employee groups whose primary purpose is to ensure we implement effective health, safety, and environment work procedures throughout our organization, including construction sites and maintenance sites, the failure to comply with such regulations or procedures could subject us to a liability. Risks Relating To Our Finances and Corporate Matters We may not have sufficient cash flow or capital resources to fund capital expenditures of our water utility business. The water utility business is capital-intensive. Expenditure levels for renewal and modernization of the system will grow at an increasing rate as components reach the end of their useful lives. SJW Group subsidiaries fund capital expenditures through a variety of sources, including cash received from operations, funds received from developers as contributions or advances, borrowings through lines of credit and debt financings, as well as equity financings by SJW Group. We cannot provide any assurance that the historical sources of funds for capital expenditures will continue to be adequate or that the cost of funds will remain at levels permitting us to earn a reasonable rate of return. A significant change in any of the funding sources could impair the ability of Water Utility Services to fund its capital expenditures, which could impact our ability to grow our utility asset base and earnings. Any increase in the cost of capital through higher interest rates or otherwise could adversely affect our results of operations. Our ability to raise capital through equity or debt may be affected by the economy and condition of the debt and equity markets. Disruptions in the capital and credit markets or deterioration in the strength of financial institutions could adversely affect SJW Groups ability to draw on its lines of credit, issue long-term debt or sell its equity. In addition, government policies, the state of the credit markets and other factors could result in increased interest rates, which would increase SJW Groups cost of capital. Furthermore, equity financings may result in dilution to our existing stockholders and debt financings may contain covenants that restrict the actions of SJW Group and its subsidiaries. We have incurred substantial additional indebtedness that may reduce our business and operational flexibility and increase our borrowing costs. We have incurred substantial indebtedness resulting in higher debt-to-equity ratio, which may have the effect, among other things, of: reducing our flexibility to respond to changing business, industry and economic conditions; increasing borrowing costs; placing us at a competitive disadvantage relative to other companies in our industry with less debt; potentially having an adverse effect on our issuer and issue ratings; requiring additional cash flow to be used to service debt instead of for other purposes; and potentially impairing our ability to obtain other financing. In addition, the terms and conditions of such indebtedness, including financial covenants and restrictive covenants, may reduce our business flexibility and adversely affect our business, financial condition, results of operations and prospects. The agreements governing the indebtedness contain covenants that impose significant operating and financial limitations and restrictions on us, including restrictions on the ability to enter particular transactions and engage in other activities that we may believe will be advisable or necessary for our business. In addition, failure to comply with any of the covenants in our existing or future debt agreements could result in a default under those agreements and under other existing agreements containing cross-default provisions. A default would permit lenders to accelerate the maturity of indebtedness under these agreements and to foreclose upon any collateral securing such indebtedness. Under certain circumstances, we may not have sufficient funds or other resources to satisfy all of our obligations under our indebtedness, including principal and interest payments, which, if not cured, may cause an event of default. The senior note borrowings of SJW Group, SJWC and SJWTX include certain financial covenants regarding a maximum debt to equity ratio and an interest coverage requirement. In the event the relevant borrower exceeds the maximum debt to equity ratio or interest coverage requirement, we may be restricted from issuing future debt. In addition, the pollution control revenue bonds issued on behalf of SJWC contain affirmative and negative covenants customary for a loan agreement relating to revenue bonds, including, among other things, certain disclosure obligations, the tax exempt status of the interest on the bonds, and limitations and prohibitions on the transfer of projects funded by the loan proceeds and assignment of the loan agreement. CTWS and its subsidiaries are required to comply with certain covenants in connection with their various long term loan agreements. The most restrictive of these covenants are the requirements to maintain a consolidated debt to capitalization ratio of not more than 60%. Additionally, Maine Water has restrictions on cash dividends paid based on restricted net assets. In the event that we violate any of these covenants, an event of default may occur and all amounts due under such loans, senior notes or bonds may come due, which would have an adverse effect on our business operations and financial conditions. SJW Group has committed to certain ring-fencing measures which will enhance CTWSs separateness from SJW Group, which may limit SJW Groups ability to influence the management and policies of CTWS (beyond the limitations included in other existing governance mechanisms). Pursuant to the agreements related to the acquisition of CTWS and commitments made by SJW Group as part of the application for PURA and MPUC approval of the acquisition of CTWS, SJW Group has instituted certain ring-fencing measures to enhance CTWSs separateness from SJW Group and to mitigate the risk that CTWS would be negatively impacted in the event of a bankruptcy or other adverse financial developments affecting SJW Group or its non-ring-fenced affiliates. These commitments became effective upon the closing of the acquisition. In order to satisfy the ring-fencing commitments, SJW Group formed SJWNE LLC a wholly-owned special purpose entity (SPE) to own the capital stock of CTWS. The SPE, CTWS and its subsidiaries (collectively, the CTWS Entities) adopted certain measures designed to enhance their separateness from SJW Group, with the intention of mitigating the effects on the CTWS Entities of any bankruptcy of SJW Group and its affiliates other than the CTWS Entities (collectively, the Non-CTWS Entities). As a result of these ring-fencing measures, in certain situations, SJW Group will be restricted in its ability to access assets of the CTWS Entities as dividends or intracompany loans to satisfy the debt or contractual obligations of any Non-CTWS Entity, including any indebtedness or other contractual obligations of SJW Group. In addition, the ring-fencing structure may negatively impact SJW Groups ability to achieve certain benefits, including synergies and economies of scale to reduce operating costs of the combined entity, that it anticipates will result from the merger. This ring-fencing structure also subjects SJW Group and the CTWS Entities to certain governance, operational and financial restrictions since the closing of the merger. Accordingly, SJW Group may be restricted in its ability to direct the management, policies and operations of the CTWS Entities, including the deployment or disposition of their respective assets, declarations of dividends, strategic planning and other important corporate issues. Further, the CTWS Entities directors have considerable autonomy and, as described in our commitments, have a duty to act in the best interest of the CTWS Entities consistent with the ring-fencing structure and applicable law, which may be contrary to SJW Groups best interests or be in opposition to SJW Groups preferred strategic direction for the CTWS Entities. To the extent they take actions that are not in SJW Groups interests, our financial condition, results of operations and prospects may be materially adversely affected. Our business strategy, which includes acquiring water systems and expanding non-tariffed services, will expose us to new risks which could have a material adverse effect on our business. Our business strategy focuses on the following: (1) Regional regulated water utility operations; (2) Regional non-tariffed water utility related services provided in accordance with the guidelines established by the Regulators; and (3) Out-of-region water and utility related services. As part of our pursuit of the above three strategic areas, we consider from time to time opportunities to acquire businesses and assets. However, we cannot be certain we will be successful in identifying and consummating any strategic business combination or acquisitions relating to such opportunities. In addition, the execution of our business strategy will expose us to different risks than those associated with the current utility operations. We expect to incur costs in connection with the execution of this strategy and any integration of an acquired business could involve significant costs, the assumption of certain known and unknown liabilities related to the acquired assets, the diversion of managements time and resources, the potential for a negative impact on SJW Groups financial position and operating results, entering markets in which SJW Group has no or limited direct prior experience and the potential loss of key employees of any acquired company. Any strategic combination or acquisition we decide to undertake may also impact our ability to finance our business, affect our compliance with regulatory requirements, and impose additional burdens on our operations. Any businesses we acquire may not achieve sales, customer growth and projected profitability that would justify the investment. Any difficulties we encounter in the integration process, including the integration of controls necessary for internal control and financial reporting, could interfere with our operations, reduce our operating margins and adversely affect our internal controls. SJW Group cannot be certain that any transaction will be successful or that it will not materially harm operating results or our financial condition. Adverse investment returns and other factors may increase our pension costs and pension plan funding requirements. A substantial number of our employees are covered by defined benefit pension plans. Our pension costs and the funded status of the plans are affected by a number of factors including the discount rate, applicable mortality tables, mortality rates of plan participants, investment returns on plan assets, and pension reform legislation. Any change in such factors could result in an increase in future pension costs and an increase in our pension liabilities, requiring an increase in plan contributions which may adversely affect our financial conditions and results of operations. SJW Groups dividend policy is subject to the discretion of our board of directors and may be limited by legal and contractual requirements. We anticipate to continue to pay a regular quarterly dividend, though any such determination to pay dividends will be at the discretion of our board of directors and will be dependent on then-existing conditions, including our financial condition, earnings, legal requirements, including limitations under Delaware law, restrictions in our credit agreements and other debt instruments that limit our ability to pay dividends to stockholders and other factors the board of directors deems relevant. The board of directors of SJW Group may, in its sole discretion, change the amount or frequency of dividends or discontinue the payment of dividends entirely. In addition, our subsidiaries may be subject to restrictions on their ability to pay dividends to us, including under state law, pursuant to regulatory commitments and under their credit agreements and other debt instruments. In this regard, the CTWS Entities are limited from paying dividends to us in certain circumstances under PURA and MPUC regulatory commitments. Any inability of our subsidiaries to pay us dividends may have a material and adverse effect on our ability to pay dividends to our stockholders. Our charter documents and Delaware law could prevent a takeover that stockholders consider favorable and could also make it more difficult for stockholders to influence our policies or may reduce the rights of stockholders. SJW Group s Certificate of Incorporation and Bylaws contain provisions that could delay or prevent a change in control of SJW Group. These provisions could also make it more difficult for our stockholders to elect directors and take other corporate actions. These provisions include, but are not limited to, the following: Authorizing Board of Directors to issue blank check preferred stock; Prohibiting cumulative voting in the election of directors; Limiting the ability of stockholders to call a special meeting of stockholders to only stockholders holding not less than 20% of outstanding voting power; and Requiring advance notification of stockholder nomination of directors and proposals. These provisions may frustrate or prevent any attempts by stockholders of SJW Group to replace or remove its current management by making it more difficult for stockholders to replace members of the Board of Directors, which is responsible for appointing the members of management. In addition, the provisions of Section 203 of the Delaware General Corporate Law (DGCL) govern SJW Group. These provisions may prohibit large stockholders, in particular those owning 15% or more of our outstanding voting stock, from merging or combining with us for a certain period of time without the consent of the Board of Directors. Furthermore, SJW Groups Certificate of Incorporation provides that a state or federal court located within Delaware is the sole and exclusive forum (unless the company consents in writing to the selection of an alternate forum) for (i) any derivative action or proceeding brought on behalf of SJW Group, (ii) any action asserting a claim of breach of a fiduciary duty owed by any director, officer or other employee of SJW Group to the company or its stockholders, (iii) any action asserting a claim arising pursuant to any provision of the DGCL, or (iv) any action asserting a claim governed by the internal affairs doctrine. Such exclusive forum provision may limit a stockholders ability to bring a claim in a judicial forum that it finds favorable for disputes with SJW Group or its directors, officers or other employees, which may discourage such lawsuits against us and our directors, officers and other employees. We may not be able to maintain adequate insurance coverage at reasonable costs, or at all, to cover all losses incurred in our operations We maintain insurance coverage as part of our overall legal and risk management strategy to minimize potential liabilities arising from our operations. Our insurance programs have varying coverage limits, deductibles, exclusions and maximums, and our insurance coverages include, workers compensation, employers liability, damage to our property, general liability, pollution liability, cybersecurity, and automobile liability. Each policy includes either deductibles or self-insured retentions and policy limits for covered claims. As a result, we may sustain losses that exceed or are excluded from our insurance coverage or for which we are self-insured. The insurance companies may also seek to challenge, reduce or deny any claims we submit, which may prevent us from recovering fully the losses we incurred. In addition, insurance companies may increase premium or deductible or reduce coverage limits based on factors that are beyond our control, including industry trends, financial conditions of insurance companies and catastrophic events such as wildfire, earthquake and pandemic. There can be no assurance that we can secure all necessary or appropriate insurance in the future, or that such insurance can be obtain at reasonable cost, or at all. General Risk Factors We operate in areas subject to natural disasters, and we may be the target of terrorist activities and other physical threats. We operate in areas that are prone to earthquakes, fires, floods, extreme weathers and other natural disasters. A significant seismic event in northern California, where the majority of our operations are concentrated, or other natural disaster in northern California, Connecticut, Texas or Maine could adversely impact our ability to deliver water to our customers and our costs of operations. A major disaster could damage or destroy our capital assets, harm our reputations and adversely affect our results of operations. The Regulators have historically allowed utilities to establish catastrophic event memorandum accounts as a possible mechanism to recover costs, such as the CEMA memorandum account in California. However, we can give no assurance that our regulators, or any other commission would allow any such cost recovery mechanism in the future. In light of the potential threats to the nations health and security due to terrorist attacks, we have taken steps to increase security measures at our facilities and heighten employee awareness of threats to our water supply. We have also tightened our security measures regarding the delivery and handling of certain chemicals used in our business. In addition, because our operation requires us to interact extensively with the general public, we may be subject to complaints, threats and potentially violent actions by our customers or the public, which may disrupt our business activities and damage our reputation. We have and will continue to bear increased costs for security precautions to protect our facilities, operations and supplies. These costs may be significant. While some of these costs are likely to be recovered in the form of higher rates, there can be no assurance that the Regulators will approve a rate increase to recover all or part of such costs and, as a result, our operating results and business may be adversely affected. Further, despite these tightened security measures, we may not be in a position to control the outcome of terrorist events should they occur. Our operations, liquidity, and earnings may be adversely affected by wildfires and risk of fire hazards. It is possible that wildfires and other fire hazards may occur more frequently, be of longer duration or impact larger areas as a result of drought-damaged plants and trees, lower humidity or higher winds that might be occurring as result of changed weather patterns. The effects of these natural disasters in Californias drought-prone areas, such as the Santa Cruz Mountains, the watershed where SJWC typically obtains approximately up to 10% of its water supply, may temporarily compromise its surface water supply resulting in disruption in our services and litigation which could adversely affect our business, operating results, and financial condition. If our surface water supply is compromised, we may have to interrupt the use of that water supply until we are able to substitute the flow of water from an alternative water source. In addition, we may incur significant costs in order to treat the impacted source through expansion of our current treatment facilities, or development of new treatment methods. If we are unable to substitute water supply from an alternative water source, or to adequately treat the impacted water source in a cost-effective manner, there may be an adverse effect on our revenues, operating results, and financial condition. The costs we incur to secure an alternative water source or an increase in draws from our underground water system could be significant and may not be recoverable in rates. Wildfires may destroy or cause damage to properties, facilities, equipment and other assets owned and operated by SJWC or result in personal injuries to our employees and personnel, which may cause temporary or permanent disruption to our water services. In such a case, we may be required to incur significant expenses to repair, replace or upgrade our assets, or to defend against costly litigation or disputes with third parties, any of which may adversely affect our business operations or financial conditions. While we maintain a business insurance policy, such policy includes limitation and retention that may reduce, or in some cases eliminate, our ability to recover all or a substantial portion of the losses and damages due to wildfire. Our inability to rely fully on insurance coverage may negatively impact our results of operations. Losses by insurance companies resulting from wildfires in California may also cause insurance coverage for wildfire risks to become more expensive or unavailable under reasonable terms, and our insurance may be inadequate to recover all our losses incurred in a wildfire. Furthermore, we might not be allowed to recover in our rates any increased costs of wildfire insurance or the costs of any uninsured wildfire losses. The price of our common stock may be volatile and may be affected by market conditions beyond our control. The trading price of our common stock may fluctuate in the future based on a variety of factors, many of which are beyond our control and unrelated to our financial results. Factors that could cause fluctuations in the trading price of our common stock include volatility of the general stock market or the utility index, regulatory developments, public announcement of material development in strategic transactions general economic conditions and trends, actual or anticipated changes or fluctuations in our results of operations, actual or anticipated changes in the expectations of investors or securities analysts, actual or anticipated developments in our competitors businesses or the competitive landscape generally, litigation involving us or our industry, and major catastrophic event(s) or sales of large blocks of our stock. Furthermore, we believe that stockholders invest in public stocks in part because they seek reliable dividend payments. If there is an oversupply of stock of public utilities in the market relative to demand by such investors, the trading price of our common stock may decrease. Additionally, if interest rates rise above the dividend yield offered by our common stock, demand for our stock and its trading price may also decrease. We must continue to attract and retain qualified technical and managerial personnel in order to succeed. Our future success depends substantially upon our ability to attract and retain highly skilled technical, operational and financial managers. There is a significant competition for such personnel in our industry. Our ability to recruit and retain qualified personnel depends on many factors, including but are not limited to, our ability to provide competitive compensation and benefit packages, availability of talents in our industry, general workforce trends and macroeconomic conditions. The loss of the services of any member of our management team or the inability to hire and retain experienced management personnel could have an adverse effect on our business, as our management team has knowledge of our industry and customers and would be difficult to replace. We try to ensure that we offer competitive compensation and benefits as well as conduct succession planning and provide opportunities for continued development, and we continually strive to recruit and train qualified personnel and retain key employees. There can be no assurance, however, that we will continue to be successful in attracting and retaining the personnel we require to grow and operate profitably.

ITEM 1. BUSINESS Item 1. Business is an outline of our strategy and our businesses by SBU, including key financial drivers. Additional items that may have an impact on our businesses are discussed in Item 1A. Risk Factors and Item 3. Legal Proceedings . Executive Summary ##TABLE_START 5 | 2022 Annual Report ##TABLE_ENDIncorporated in 1981, AES is a global energy company accelerating the future of energy. Together with our many stakeholders, we are improving lives by delivering the greener, smarter energy solutions the world needs. Our diverse workforce is committed to continuous innovation and operational excellence, while partnering with our customers on their strategic energy transitions and continuing to meet their energy needs today. Our Strategy AES is an industry leader in developing and operating the solutions that will enable the transition to zero and low-carbon sources of energy and achievement of the Paris Agreement's goal of net-zero emissions by 2050. Today we see an enormous business opportunity from the once-in-a-lifetime transformation of the electricity sector driven by decarbonization, electrification, and digitalization. There is a substantial need for more renewable energy as well as an opportunity for innovation to develop new products and solutions that help customers accomplish their individual decarbonization goals. The focus of our strategy continues to be on partnering with large companies that are looking to transition to carbon-free sources of electricity. As an indication of our success, in 2022 we were recognized by BNEF as the #1 global clean energy developer for corporations. In 2022, we signed long-term contracts for 5.2 GW of renewable power, bringing our backlog of projects those with signed contracts, but which are not yet in operation to 12.2 GW. Our backlog serves as the core component of future growth. Central to our renewables growth strategy is a focus on customer collaboration and co-creation, which helps us develop unique solutions tailored to a specific customer's needs. This approach not only contributes to customer satisfaction and repeat business, but it also allows AES to work with key customers on a bilateral basis rather than just through participation in bid processes. This approach has led to the co-creation of several first-of-its-kind industry innovations, including agreements to supply 24/7 carbon-free energy for global data center companies. Our unique capabilities in developing tailored energy solutions, enabled us to partner with Air Products to announce our plans to develop, build, own, and operate the largest green hydrogen production facility to date in the United States. We are also working with some of the world's largest mining companies in their transition to renewable energy in South America, essentially reducing the emissions of major supply chains. One way in which we are serving the ##TABLE_START 6 | 2022 Annual Report ##TABLE_ENDmining industry is through our Green Blend offering, in which we work to integrate renewable energy with thermal power during select hours of the day, reducing overall thermal generation and lowering emissions. With our utilities, we are working with a broad range of stakeholders to transition to lower carbon forms of energy while promoting a Just Transition for the workers and communities who may be negatively impacted by the closure of fossil fuel facilities. At AES Indiana, for example, we are working to retire its remaining coal generation by the end of 2025, while adding new renewables and natural gas to the grid. Our renewable growth strategy includes taking steps to ensure and enable growth in future years. We massively expanded our pipeline of development projects, which grew from 55 GW in January 2022 to 64 GW as of the end of 2022, both through acquisitions and increased investment in development activities, such as securing land or advancing permitting and interconnection processes. For our projects in late-stage development, we worked to secure supplier arrangements to avoid any potential delays in relation to industry shortages, aided by our scale, supplier relationships, and advanced planning measures. A substantial portion of our expected capital expenditures through 2025 will be related to the development of renewable projects. We are also developing and incubating new technologies that add value today and will drive our business in the future. We understand that the energy industry is changing rapidly, and aim to proactively seek solutions that will give us a continued competitive advantage. At the core of our innovation strategy is AES Next, our business and technology incubator. AES Next works to identify new and innovative technologies and business opportunities that provide or support leading-edge greener energy solutions. 2022 Strategic Highlights We signed 5,153 MW of renewables and energy storage under long-term PPAs, including 2,553 MW of solar, wind and energy storage in the United States. We completed the construction or acquisition of operating projects totaling 1,943 MW in the United States, Brazil, the Dominican Republic, Chile and Colombia, primarily wind, solar and energy storage. Our backlog, which includes projects with signed contracts, but which are not yet operational, is now 12,179 MW, consisting of: 5,453 MW under construction; and 6,726 MW with signed PPAs, but that are not yet under construction. We announced a partnership with Air Products to develop, build, own and operate the largest green hydrogen production facility to date in the United States. Includes approximately 1.4 GW of wind and solar generation, along with electrolyzer capacity capable of producing over 200 metric tons per day (MT/D) of green hydrogen. The Company expects to announce certain internal management changes which will result in modifications to its financial reporting segments. Overview Generation We currently own and/or operate a generation portfolio of 32,326 MW, including generation from our integrated utility, AES Indiana. Our generation fleet is diversified by fuel type. See discussion below under Fuel Costs . Performance drivers of our generation businesses include types of electricity sales agreements, plant reliability and flexibility, availability of generation capacity to meet contracted sales, fuel costs, seasonality, weather variations, economic activity, fixed-cost management, and competition. The financial performance of our renewables business is also impacted by our ability to complete construction projects and earn U.S. renewable tax credits. Contract Sales Most of our generation businesses sell electricity under medium- or long-term contracts ("contract sales") or under short-term agreements in competitive markets ("short-term sales"). Our medium-term contract sales have terms of two to five years, while our long-term contracts have terms of more than five years. Contracts requiring fuel to generate energy, such as natural gas or coal, are structured to recover variable costs, including fuel and variable OM costs, either through direct or indexation-based contractual pass-throughs or tolling arrangements. When the contract does not include a fuel pass-through, we typically hedge fuel costs or enter into fuel or energy supply agreements for a similar contract period (see discussion below under Fuel Costs). These ##TABLE_START 7 | 2022 Annual Report ##TABLE_ENDcontracts also help us to fund a significant portion of the total capital cost of the project through long-term non-recourse project-level financing. Certain contracts include capacity payments that cover projected fixed costs of the plant, including fixed OM expenses, debt service, and a return on capital invested. In addition, most of our contracts require that the majority of the capacity payments be denominated in the currency matching our fixed costs. Contracts that do not have significant fuel cost or do not contain a capacity payment are structured based on long-term spot prices with some negotiated pass-through costs, allowing us to recover expected fixed and variable costs as well as provide a return on investment. These contracts are intended to reduce exposure to the volatility of fuel and electricity prices by linking the business's revenues and costs. We generally structure our business to eliminate or reduce foreign exchange risk by matching the currency of revenue and expenses, including fixed costs and debt. Our project debt may consist of both fixed and floating rate debt for which we typically hedge a significant portion of our exposure.

Some of our contracted businesses also receive a regulated market-based capacity payment, which is discussed in more detail in the Short-Term Sales section below. Thus, these contracts, or other related commercial arrangements, significantly mitigate our exposure to changes in power and, as applicable, fuel prices, currency fluctuations and changes in interest rates. In addition, these contracts generally provide for a recovery of our fixed operating expenses and a return on our investment, as long as we operate the plant to the reliability and efficiency standards required in the contract. Short-Term Sales Our other generation businesses sell power and ancillary services under short-term contracts with average terms of less than two years, including spot sales, directly in the short-term market or at regulated prices. The short-term markets are typically administered by a system operator to coordinate dispatch. Short-term markets generally operate on merit order dispatch, where the least expensive generation facilities, based upon variable cost or bid price, are dispatched first and the most expensive facilities are dispatched last. The short-term price is typically set at the marginal cost of energy or bid price (the cost of the last plant required to meet system demand). As a result, the cash flows and earnings associated with these businesses are more sensitive to fluctuations in the market price for electricity. In addition, many of these wholesale markets include markets for ancillary services to support the reliable operation of the transmission system. Across our portfolio, we provide a wide array of ancillary services, including voltage support, frequency regulation and spinning reserves. Many of the short-term markets in which we operate include regulated capacity markets. These capacity markets are intended to provide additional revenue based upon availability without reliance on the energy margin from the merit order dispatch. Capacity markets are typically priced based on the cost of a new entrant and the system capacity relative to the desired level of reserve margin (generation available in excess of peak demand). Our generating facilities selling in the short-term markets typically receive capacity payments based on their availability in the market. Plant Reliability and Flexibility Our contract and short-term sales provide incentives to our generation plants to optimally manage availability, operating efficiency and flexibility. Capacity payments under contract sales are frequently tied to meeting minimum standards. In short-term sales, our plants must be reliable and flexible to capture peak market prices and to maximize market-based revenues. In addition, our flexibility allows us to capture ancillary service revenue while meeting local market needs. Fuel Costs For our thermal generation plants, fuel is a significant component of our total cost of generation. For contract sales, we often enter into fuel supply agreements to match the contract period, or we may financially hedge our fuel costs. Some of our contracts include indexation for fuels. In those cases, we seek to match our fuel supply agreements to the indexation. For certain projects, we have tolling arrangements where the power offtaker is responsible for the supply and cost of fuel to our plants. In short-term sales, we sell power at market prices that are generally reflective of the market cost of fuel at the time, and thus procure fuel supply on a short-term basis, generally designed to match up with our market sales profile. Since fuel price is often the primary determinant for power prices, the economics of projects with short-term sales are often subject to volatility of relative fuel prices. For further information regarding commodity price risk please see Item 7A. Quantitative and Qualitative Disclosures about Market Risk in this Form 10-K. 46% of the capacity of our generation plants are fueled by renewables, including hydro, solar, wind, energy storage, biomass and landfill gas, which do not have significant fuel costs. ##TABLE_START 8 | 2022 Annual Report ##TABLE_END32% of the capacity of our generation plants are fueled by natural gas. With the exception of our plants in the Dominican Republic and Panama, where we import LNG to utilize in the local market, we use gas from local suppliers in each market. 20% of the capacity of our generation fleet is coal-fired. In the U.S., most of our coal-fired plants are supplied from domestic coal. At our non-U.S. generation plants, and at our plant in Puerto Rico, we source coal from a mix of sources from the international market and in the local jurisdictions. To the extent possible, we utilize our global sourcing program to maximize the purchasing power of our fuel procurement. 2% of the capacity of our generation fleet utilizes pet coke, diesel or oil for fuel. We source oil and diesel locally at prices linked to international markets. We largely source pet coke from Mexico and the U.S. Seasonality, Weather Variations and Economic Activity Our generation businesses are affected by seasonal weather patterns and, therefore, operating margin is not generated evenly throughout the year. Additionally, weather variations, including temperature, solar and wind resources, and hydrological conditions, may also have an impact on generation output at our renewable generation facilities. In competitive markets for power, local economic activity can also have an impact on power demand and short-term prices for power. Fixed-Cost Management In our businesses with long-term contracts, the majority of the fixed OM costs are recovered through the capacity payment. However, for all generation businesses, managing fixed costs and reducing them over time is a driver of business performance. Competition For our businesses with medium- or long-term contracts, there is limited competition during the term of the contract. For short-term sales, plant dispatch and the price of electricity are determined by market competition and local dispatch and reliability rules. Utilities Our utility businesses consist of AES Indiana and AES Ohio in the U.S. and four utilities in El Salvador. AES' six utility businesses distribute power to 2.6 million customers and AES' two utilities in the U.S. also include generation capacity totaling 3,495 MW. AES Indiana, our fully integrated utility, and AES Ohio, our transmission and distribution regulated utility, operate as the sole distributors of electricity within their respective jurisdictions. AES Indiana owns and operates all of the facilities necessary to generate, transmit and distribute electricity. AES Ohio owns and operates all of the facilities necessary to transmit and distribute electricity. At our distribution business in El Salvador, we face limited competition due to significant barriers to enter the market. According to El Salvador's regulation, large regulated customers have the option of becoming unregulated users and requesting service directly from generation or commercialization agents. In general, our utilities sell electricity directly to end-users, such as homes and businesses, and bill customers directly. Key performance drivers for utilities include the regulated rate of return and tariff, seasonality, weather variations, economic activity and reliability of service. Revenue from utilities is classified as regulated on the Consolidated Statements of Operations. Regulated Rate of Return and Tariff In exchange for the right to sell or distribute electricity in a service territory, our utility businesses are subject to government regulation. This regulation sets the framework for the prices ("tariffs") that our utilities are allowed to charge customers for electricity and establishes service standards that we are required to meet. Our utilities are generally permitted to earn a regulated rate of return on assets, determined by the regulator based on the utility's allowed regulatory asset base, capital structure and cost of capital. The asset base on which the utility is permitted a return is determined by the regulator, within the framework of applicable local laws, and is based on the amount of assets that are considered used and useful in serving customers. Both the allowed return and the asset base are important components of the utility's earning power. The allowed rate of return and operating expenses deemed reasonable by the regulator are recovered through the regulated tariff that the utility charges to its customers. The tariff may be reviewed and reset by the regulator from time to time depending on local regulations, or the utility may seek a change in its tariffs. The tariff is generally based upon usage level and may include a pass-through of costs that are not controlled by the utility, such as the costs of fuel (in the case of integrated utilities) and/or the costs of purchased energy, to the customer. Components of the tariff that are directly passed through to the ##TABLE_START 9 | 2022 Annual Report ##TABLE_ENDcustomer are usually adjusted through a summary regulatory process or an existing formula-based mechanism. In some regulatory regimes, customers with demand above an established level are unregulated and can choose to contract directly with the utility or with other retail energy suppliers and pay non-bypassable fees, which are fees to the distribution company for use of its distribution system. The regulated tariff generally recognizes that our utility businesses should recover certain operating and fixed costs, as well as manage uncollectible amounts, quality of service and technical and non-technical losses. Utilities, therefore, need to manage costs to the levels reflected in the tariff, or risk non-recovery of costs or diminished returns. Seasonality, Weather Variations, and Economic Activity Our utility businesses are generally affected by seasonal weather patterns and, therefore, operating margin is not generated evenly throughout the year. Additionally, weather variations may also have an impact based on the number of customers, temperature variances from normal conditions, and customers' historic usage levels and patterns. Retail sales, after adjustments for weather variations, are also affected by changes in local economic activity, energy efficiency and distributed generation initiatives, as well as the number of retail customers. Reliability of Service Our utility businesses must meet certain reliability standards, such as duration and frequency of outages. Those standards may be explicit, with defined performance incentives or penalties, or implicit, where the utility must operate to meet customer and/or regulator expectations. Development and Construction We develop and construct new generation facilities. For our utility business, new plants may be built or existing plants retrofitted in response to customer needs or to comply with regulatory developments. The projects are developed subject to regulatory approval that permits recovery of our capital cost and a return on our investment. For our generation businesses, our priority for development is in key growth markets, where we can leverage our global scale and synergies with our existing businesses by adding renewable energy. We make the decision to invest in new projects by evaluating the strategic fit, project returns and financial profile against a fair risk-adjusted return for the investment and against alternative uses of capital, including corporate debt repayment. In some cases, we enter into long-term contracts for output from new facilities prior to commencing construction. To limit required equity contributions from The AES Corporation, we also seek non-recourse project debt financing and other sources of capital, including partners, when it is commercially attractive. We typically contract with a third party to manage construction, although our construction management team supervises the construction work and tracks progress against the project's budget and the required safety, efficiency and productivity standards. Segments The segment reporting structure uses the Company's management reporting structure as its foundation to reflect how the Company manages the businesses internally and is mainly organized by geographic regions which provides a socio-political-economic understanding of our business. We are organized into four market-oriented SBUs: US and Utilities (United States, Puerto Rico and El Salvador); South America (Chile, Colombia, Argentina and Brazil); MCAC (Mexico, Central America and the Caribbean); and Eurasia (Europe and Asia) which are led by our SBU Presidents. We have two lines of business: generation and utilities. Each of our SBUs participates in our first business line, generation, in which we own and/or operate power plants to generate and sell power to customers, such as utilities, industrial users, and other intermediaries. Our US and Utilities SBU participates in our second business line, utilities, in which we own and/or operate utilities to generate or purchase, distribute, transmit and sell electricity to end-user customers in the residential, commercial, industrial and governmental sectors within a defined service area. In certain circumstances, our utilities also generate and sell electricity on the wholesale market. We measure the operating performance of our SBUs using Adjusted PTC, a non-GAAP measure. The Adjusted PTC by SBU for the year ended December 31, 2022 is shown below. The percentages for Adjusted PTC are the contribution by each SBU to the gross metric, i.e., the total Adjusted PTC by SBU, before deductions for Corporate. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of OperationsSBU Performance Analysis of this Form 10-K for reconciliation and definitions of Adjusted PTC. ##TABLE_START 10 | 2022 Annual Report ##TABLE_ENDFor financial reporting purposes, the Company's corporate activities and certain other investments are reported within "Corporate and Other" because they do not require separate disclosure. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 18 Segment and Geographic Information included in Item 8. Financial Statements and

Supplementary Data of this Form 10-K for further discussion of the Company's segment structure. ##TABLE_START 11 | 2022 Annual Report ##TABLE_END##TABLE_START (1) Non-GAAP measure. See Item 7. Managements Discussion and Analysis of Financial Condition and Results of Operations SBU Performance AnalysisNon-GAAP Measures for reconciliation and definition. ##TABLE_END##TABLE_START 12 | 2022 Annual Report ##TABLE_ENDUS and Utilities SBU Our US and Utilities SBU has 47 generation facilities, two utilities in the United States, and four utilities in El Salvador. Generation Operating installed capacity of our US and Utilities SBU totals 13,108 MW. IPALCO (AES Indiana's parent), AES Ohio, and DPL Inc. (AES Ohio's parent) are all SEC registrants, and as such, follow the public filing requirements of the Securities Exchange Act of 1934. The following table lists our US and Utilities SBU generation facilities: ##TABLE_START Business Location Fuel Gross MW AES Equity Interest Year Acquired or Began Operation Contract Expiration Date Customer(s) Bosforo (1) El Salvador Solar 100 50 % 2018-2019 2043-2044 CAESS, EEO, CLESA, DEUSEM Cuscatlan Solar (1) El Salvador Solar 10 50 % 2021 2046 CLESA AES Nejapa El Salvador Landfill Gas 6 100 % 2011 2035 CAESS Opico El Salvador Solar 4 100 % 2020 2040 CLESA Moncagua El Salvador Solar 3 100 % 2015 2035 EEO El Salvador Subtotal 123 SouthlandAlamitos US-CA Gas 1,200 100 % 1998 2023 Various sPower OpCo A (1) US-Various Solar 967 26 % 2017-2019 2028-2046 Various Wind 140 SouthlandRedondo Beach US-CA Gas 876 100 % 1998 2023 Various Southland EnergyAlamitos (5) US-CA Gas 697 50 % 2020 2040 Southern California Edison Southland EnergyHuntington Beach (5) US-CA Gas 694 50 % 2020 2040 Southern California Edison New York Wind (2) US-NY Wind 612 75 % 2021 NYISO AES Puerto Rico US-PR Coal 524 100 % 2002 2027 LUMA Energy AES Renewable Holdings (3) US-Various Solar 400 100 % 2015-2022 2029-2042 Utility, Municipality, Education, Non-Profit Energy Storage 90 Highlander (sPower OpCo B (1)) US-VA Solar 485 50 % 2020 2035 Apple, Akami, Etsy, Microsoft sPower OpCo B (1) US-Various Solar 260 50 % 2019 2039-2044 Various SouthlandHuntington Beach US-CA Gas 236 100 % 1998 2023 Various Buffalo Gap II (3) US-TX Wind 228 100 % 2007 Warrior Run US-MD Coal 205 100 % 2000 2030 Potomac Edison Prevailing Winds (sPower OpCo B (1)) US-SD Wind 200 50 % 2020 2050 Prevailing Winds Skipjack (2) (3) US-VA Solar 175 75 % 2022 2036 Exelon Generation Company Buffalo Gap III (3) US-TX Wind 170 100 % 2008 Lancaster Area Battery (2) (3) US-CA Energy Storage 127 75 % 2022 Buffalo Gap I (3) US-TX Wind 121 100 % 2006 Southland EnergyAlamitos Energy Center (5) US-CA Energy Storage 100 50 % 2021 2041 Southern California Edison East Line Solar (sPower OpCo B (1)) US-AZ Solar 100 50 % 2020 2045 Salt River Project Central Line (sPower OpCo B (1)) US-AZ Solar 100 50 % 2022 2039 Salt River Project Agricultural Improvement Power District West Line (sPower (1)) US-AZ Solar 100 50 % 2022 Luna (2) (3) US-CA Energy Storage 100 75 % 2022 Laurel Mountain Repowering (2) US-WV Wind 99 75 % 2022 2037 AES Solutions Management, LLC Clover Creek (sPower OpCo B (1)) US-UT Solar 80 50 % 2021 2046 UMPA Mountain View Repowering (2) (3) US-CA Wind 71 75 % 2022 2042 Southern California Edison Michigan Consumers

Ticker: AES, Sector: Utilities, Filed At: 2023-03-01T16:44:29-05:00

(2) (3) US-MI Solar 36 75 % 2022 Big Island Waikoloa (3) (4) US-HI Solar 25 100 % 2022 Energy Storage 30 Mountain View IV (4) US-CA Wind 49 100 % 2012 2032 Southern California Edison ##TABLE_END##TABLE_START 13 | 2022 Annual Report ##TABLE_END##TABLE_START Lawa'i (3) (4) US-HI Solar 20 100 % 2018 2043 Kaua'i Island Utility Cooperative Energy Storage 20 sPower OpCo C (1) US-CA Solar 30 50 % 2021-2022 2041 Various Energy Storage 2 Kekaha (3) (4) US-HI Solar 14 100 % 2019 2045 Kaua'i Island Utility Cooperative Energy Storage 14 Na Pua Makani (4) US-HI Wind 24 100 % 2020 2040 HECO Ilumina US-PR Solar 24 100 % 2012 2037 LUMA Energy Laurel Mountain ES US-WV Energy Storage 16 100 % 2011 Community Energy (2) US-Various Solar 14 75 % 2022 2023-2043 Various Southland EnergyAES Gilbert (Salt River (5) (6)) US-AZ Energy Storage 10 50 % 2019 2039 Salt River Project Agricultural Improvement Power District Warrior Run ES US-MD Energy Storage 5 100 % 2016 United States Subtotal 9,490 9,613 ##TABLE_END_______________________________ (1) Unconsolidated entity, accounted for as an equity affiliate. (2) Owned by AES Clean Energy Development ("ACED"). (3) AES owns these assets together with third-party tax equity investors with variable ownership interests. The tax equity investors receive a portion of the economic attributes of the facilities, including tax attributes, that vary over the life of the projects. The proceeds from the issuance of tax equity are recorded as Noncontrolling interest or Redeemable stock of subsidiaries in the Company's Consolidated Balance Sheets, depending on the partnership rights of the specific project. (4) Owned by AES Renewable Holdings. (5) On December 1, 2022, Southland Energy sold an additional 14.9% ownership interest in the Southland Energy assets. Following the sale, AES holds 50.1% of Southland Energy's interest and this business continues to be consolidated by AES. (6) Facility experienced a fire event in April 2022 which rendered the asset currently inoperable. Utilities The following table lists our utilities and their generation facilities. ##TABLE_START Business Location Approximate Number of Customers Served as of 12/31/2022 GWh Sold in 2022 Fuel Gross MW AES Equity Interest Year Acquired or Began Operation CAESS El Salvador 647,000 2,109 75 % 2000 CLESA El Salvador 461,000 1,072 80 % 1998 DEUSEM El Salvador 92,000 161 74 % 2000 EEO El Salvador 348,000 700 89 % 2000 El Salvador Subtotal 1,548,000 4,042 AES Ohio (1) US-OH 536,000 13,875 100 % 2011 AES Indiana (2) US-IN 519,000 15,385 Coal/Gas/Oil/Energy Storage 3,495 70 % 2001 United States Subtotal 1,055,000 29,260 3,495 2,603,000 33,302 ##TABLE_END_______________________________ (1) AES Ohio's GWh sold in 2022 represent total transmission and distribution sales. AES Ohio's wholesale sales and SSO utility sales, which are sales to utility customers who use AES Ohio to source their electricity through a competitive bid process, were 4,676 GWh in 2022. AES Ohio owns a 4.9% equity ownership in OVEC, an electric generating company. OVEC has two plants in Cheshire, Ohio and Madison, Indiana with a combined generation capacity of approximately 2,109 MW. AES Ohios share of this generation is approximately 103 MW. (2) CDPQ owns direct and indirect interests in IPALCO (AES Indiana's parent)

which total approximately 30%. AES owns 85% of AES US Investments and AES US Investments owns 82.35% of IPALCO. AES Indiana plants: Georgetown, Harding Street, Petersburg and Eagle Valley. 20 MW of AES Indiana total is considered a transmission asset. AES Indiana retired the 230 MW Petersburg Unit 1 in May 2021 and has plans to retire the 415 MW Petersburg Unit 2 in June 2023. AES Indiana plans to convert the remaining two coal units at Petersburg to natural gas by the end of 2025. In December 2021, AES Indiana completed the acquisition of the 195 MW Hardy Hills solar project, which is expected to commence operations in 2024. In November 2021, AES Indiana received an order from the IURC approving the acquisition of a 250 MW solar and 180 MWh energy storage facility (Petersburg solar project), which is expected to be completed in 2025. ##TABLE_START 14 | 2022 Annual Report ##TABLE_ENDUnder construction The following table lists our plants under construction in the US and Utilities SBU: ##TABLE_START Business Location Fuel Gross MW AES Equity Interest Expected Date of Commercial Operations Cement City (1) US-MI Solar 20 75 % 1H 2023 Big Island Waikoloa (2) US-HI Solar 5 100 % 1H 2023 West Oahu Solar (2) US-HI Solar 13 100 % 1H 2023 Energy Storage 13 High Mesa (1) US-CO Solar 10 75 % 1H 2023 Energy Storage 10 Meanguera del Golfo El Salvador Solar 1 100 % 1H 2023 Energy Storage 4 AES Clean Energy Development US-Various Solar 32 75 % 1H-2H 2023 Great Cove 12 (1) US-PA Solar 220 75 % 2H 2023 Chevelon Butte (1) US-AZ Wind 238 75 % 2H 2023 McFarland Phase 1 (1) US-AZ Solar 200 75 % 2H 2023 Energy Storage 100 Kuihelni (2) US-HI Solar 60 100 % 2H 2023 Energy Storage 60 Oak Ridge (1) US-LA Solar 200 75 % 2H 2023 Baldy Mesa (1) US-CA Solar 150 75 % 2H 2023 Energy Storage 75 Estrella (sPower) US-CA Solar 56 50 % 2H 2023 Energy Storage 28 Cavalier (1) US-VA Solar 155 75 % 2H 2023-1H 2024 Raceway 1 (sPower) US-CA Solar 125 50 % 2H 2023-1H 2024 Energy Storage 80 Platteview (1) US-NE Solar 81 75 % 1H 2024 McFarland Phase 2 (1) US-AZ Solar 300 75 % 1H 2024 Energy Storage 150 Delta (1) US-MS Wind 185 75 % 1H 2024 Hardy Hills (AES Indiana) US-IN Solar 195 70 % 1H 2024 Cavalier Solar A2 (1) US-VA Solar 81 75 % 2H 2024 Chevelon Butte Phase II (1) US-AZ Wind 216 50 % 2H 2024 3,062 ##TABLE_END_______________________________ (1) Owned by AES Clean Energy Development ("ACED"). (2) Owned by AES Renewable Holdings. The majority of projects under construction have executed long-term PPAs or, as applicable, have been assigned tariffs through a regulatory process. In July 2020, the Hawaii State Legislature passed Senate Bill 2629, which prohibited AES Hawaii from generating electricity from coal after December 31, 2022. As a result, AES retired the AES Hawaii facility in September 2022. ##TABLE_START 15 | 2022 Annual Report ##TABLE_ENDThe following map illustrates the locations of our US and Utilities facilities: US and Utilities Businesses AES Indiana Business Description IPALCO is a holding company whose principal subsidiary is AES Indiana. AES Indiana is an integrated utility that is engaged primarily in generating, transmitting, distributing, and selling electric energy to retail customers in the city of Indianapolis and neighboring areas within the state of Indiana and is subject to regulatory authoritysee Regulatory

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Framework and Market Structure below. AES Indiana has an exclusive right to provide electric service to the customers in its service area, covering about 528 square miles with an estimated population of approximately 971,000 people. AES Indiana owns and operates four generating stations, all within the state of Indiana. AES Indianas largest generating station, Petersburg, is coal-fired. AES Indiana retired 230 MW Petersburg Unit 1 on May 31, 2021 and has plans to retire 415 MW Petersburg Unit 2 in 2023, which would result in 630 MW of total retired economic capacity at this station. AES Indiana plans to convert the remaining two coal units at Petersburg to natural gas by the end of 2025 (see Integrated Resource Plan below). The second largest station, Harding Street, uses natural gas and fuel oil to power combustion turbines. In addition, AES Indiana operates a 20 MW battery-based energy storage unit at this location, which provides frequency response. The third station, Eagle Valley, is a CCGT natural gas plant. The fourth station, Georgetown, is a small peaking station that uses natural gas to power combustion turbines. In addition, AES Indiana helps meet its customers' energy needs with long-term contracts for the purchase of 300 MW of wind-generated electricity and 94 MW of solar-generated electricity. In July 2021, AES Indiana executed an agreement to acquire a 250 MW solar and 180 MWh energy storage facility (the "Petersburg Solar Project"). As amended in October 2022 and subject to IURC approval, the Petersburg Solar Project is now expected to be completed in 2025. In December 2021, AES Indiana completed the acquisition of Hardy Hills Solar Energy LLC, including the development of a 195 MW solar project (the "Hardy Hills Solar Project"). As amended in December 2022 and subject to IURC approval, the Hardy Hills Solar Project is now expected to be completed in 2024. Key Financial Drivers AES Indiana's financial results are driven primarily by retail demand, weather, and maintenance costs. In addition, AES Indiana's financial results are likely to be driven by many other factors including, but not limited to: regulatory outcomes and impacts; ##TABLE_START 16 | 2022 Annual Report ##TABLE_END the passage of new legislation, implementation of regulations, or other changes in regulation; and timely recovery of capital expenditures. Regulatory Framework and Market Structure AES Indiana is subject to comprehensive regulation by the IURC with respect to its services and facilities, retail rates and charges, the issuance of long-term securities, and certain other matters. The regulatory authority of the IURC over AES Indiana's business is typical of regulation generally imposed by state public utility commissions. The IURC sets tariff rates for electric service provided by AES Indiana. The IURC considers all allowable costs for ratemaking purposes, including a fair return on assets used and useful to providing service to customers. AES Indiana's tariff rates for electric service to retail customers consist of basic rates and approved charges. In addition, AES Indiana's rates include various adjustment mechanisms, including, but not limited to: (i) a rider to reflect changes in fuel and purchased power costs to meet AES Indiana's retail load requirements, referred to as the Fuel Adjustment Charge, (ii) a rider for the timely recovery of costs incurred to comply with environmental laws and regulations, including a return, (iii) a rider to reflect changes in ongoing RTO costs, (iv) riders for passing through to customers wholesale sales margins and capacity sales above and below established annual benchmarks, (v) a rider for a return on, and of, investments for eligible TDSIC improvements, and (vi) a rider for cost recovery, lost margin recoveries and performance incentives from AES Indiana's demand side management energy efficiency programs. Each of these tariff rate components function somewhat independently of one another, but the overall structure of AES Indiana's rates is subject to review at the time of any review of AES Indiana's basic rates and charges. Additionally, AES Indiana's rider recoveries are reviewed through recurring filings. On October 31, 2018, the IURC issued an order approving an uncontested settlement agreement to increase AES Indiana's annual revenues by $44 million, or 3% (the "2018 Base Rate Order"). This revenue increase primarily includes recovery through rates of costs associated with the CCGT at Eagle Valley, completed in the first half of 2018, and other construction projects. New base rates and charges became effective on December 5, 2018. The 2018 Base Rate Order was AES Indiana's most recent base rate order and also provided customers with approximately $50 million in benefits through a rate adjustment mechanism over a two-year period. AES Indiana is one of many transmission system owner members in MISO, an RTO which maintains functional control over the combined transmission systems of its members and manages one of the largest energy and ancillary services markets in the U.S. MISO dispatches generation assets in economic order considering transmission constraints and other reliability issues to meet the total demand in the MISO region. AES Indiana offers electricity in the MISO day-ahead and real-time markets. Development Strategy AES Indiana's construction program is composed of capital expenditures necessary for prudent utility operations and compliance with environmental regulations, along with discretionary investments designed to replace aging equipment or improve overall performance. Senate Enrolled Act 560, the Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") statute, provides for cost recovery outside of a base rate proceeding for new or replacement electric and gas transmission, distribution, and storage projects that a public utility undertakes for the purposes of safety, reliability, system modernization, or economic development. Provisions of the TDSIC statute require that requests for recovery include a plan of at least five years and not more than seven for eligible investments. Once a plan is approved by the IURC, eighty percent of eligible costs can be recovered using a periodic rate adjustment mechanism, referred to as a TDSIC mechanism. Recoverable costs include a return on, and of, the investment, including AFUDC, post-in-service carrying charges, operation and maintenance expenses, depreciation, and property taxes. The remaining twenty percent of recoverable costs are deferred for future recovery in the public utilitys next base rate case. The TDSIC mechanism is capped at an annual increase of two percent of total retail revenues. On March 4, 2020, the IURC issued an order approving the projects in AES Indiana's seven-year TDSIC Plan for eligible transmission, distribution, and storage system improvements totaling $1.2 billion from 2020 through 2026. Beginning in June 2020, AES Indiana files an annual TDSIC rate adjustment for a return on, and of, investments through March 31 with rates requested to be effective each November. Annual TDSIC plan update filings are required to be staggered by six months as ordered by the IURC and are filed each December. The total amount of AES Indianas equipment approved for TDSIC recovery as of December 31, 2022 was $324 million. Integrated Resource Plan In December 2022, AES Indiana filed its Integrated Resource Plan ("IRP"), which describes AES Indiana's Preferred Resource Portfolio for meeting generation capacity needs for serving AES Indiana's retail customers over the next several years. The Preferred Resource Portfolio is AES Indiana's reasonable least cost option and provides a cleaner and more diverse generation mix for customers. The 2022 IRP ##TABLE_START 17 | 2022 Annual Report ##TABLE_ENDshort-term action plan includes converting the two remaining coal units at Petersburg to natural gas by the end of 2025. AES Indiana has not yet filed for the necessary regulatory approvals from the IURC to convert Petersburg units 3 and 4, however, AES Indiana expects to do so at the appropriate time. Additionally, AES Indiana plans to add up to 1,300 MW of wind, solar, and battery energy storage by 2027. As new technologies, such as green hydrogen, small modular reactors and carbon capture are developed and cost effective, we will evaluate them in the future planning processes AES Indiana's 2019 IRP included the retirement of 230 MW Petersburg Unit 1 on May 31, 2021 and plans to retire 415 MW Petersburg Unit 2 in 2023. In November 2021, AES Indiana received approval from the IURC for approvals and cost recovery associated with the Petersburg retirements, which includes: (1) AES Indiana's creation of regulatory assets for the net book value of Petersburg units 1 and 2 upon retirement; (2) a method for amortization of the regulatory assets; and (3) recovery of the regulatory assets through ongoing amortization in AES Indianas future rate cases. The order reserves all rights of all the parties with respect to the ratemaking treatment related to the regulatory assets, including the proper rate of return and mechanisms for recovery. In December 2021, AES Indiana completed the acquisition of the Hardy Hills Solar Project, which is a 195 MW solar project to be developed and expected to commence operations in 2024. AES Indiana received an order from the IURC approving the project in June of 2021. In July 2021, AES Indiana executed an agreement to acquire the Petersburg Solar Project, which is a 250 MW solar and 180 MWh energy storage facility expected to commence operations in 2025. In November 2021, AES Indiana received an order from the IURC approving the project. In December 2021 and 2022, AES Indiana received equity capital contributions of $275 million and $253 million, respectively, from AES and CDPQ on a proportional share basis to be used for funding needs related to AES Indianas TDSIC and replacement generation projects. AES Ohio Business Description DPL is a holding company whose principal subsidiary is AES Ohio. AES Ohio is a utility company that transmits and distributes electricity to approximately 536,000 retail customers in a 6,000 square mile area of West Central Ohio and is subject to regulatory authoritysee Regulatory Framework and Market Structure below. AES Ohio has the exclusive right to provide transmission and distribution services to its customers, and procures retail standard service offer ("SSO") electric service on behalf of residential, commercial, industrial, and governmental customers through a competitive bid auction process. In previous years, AES Ohio Generation was also a primary subsidiary, but DPL has systematically exited this generation business. AES Ohio Generation retired and sold its last remaining operating asset in 2020. Key Financial Drivers AES Ohio's financial results are driven primarily by retail demand and weather. AES Ohio's financial results are likely to be driven by other factors as well, including, but not limited to: regulatory outcomes and impacts; the passage of new legislation, implementation of regulations, or other changes in regulations; and timely recovery of transmission and distribution expenditures. Regulatory Framework and Market Structure AES Ohio is regulated by the PUCO for its distribution services and facilities, retail rates and charges, reliability of service, compliance with renewable energy portfolio requirements, energy efficiency program requirements, and certain other matters. The PUCO maintains jurisdiction over the delivery of electricity, SSO, and other retail electric services. Electric customers within Ohio are permitted to purchase power under contract from a Competitive Retail Electric Service ("CRES") provider or from their local utility under SSO rates. The SSO generation supply is provided by third parties through a competitive bid process. Ohio utilities have the exclusive right to provide transmission and distribution services in their state-certified territories. While Ohio allows customers to choose retail generation providers, AES Ohio is required to provide retail generation service at SSO rates to any customer that has not signed a contract with a CRES provider or as a provider of last resort in the event of a CRES provider default. SSO rates are subject to rules and regulations of the PUCO and are established through a competitive bid process for the supply of power to SSO customers. AES Ohio's distribution rates are regulated by the PUCO and are established through a traditional cost-based rate-setting process. AES Ohio is permitted to recover its costs of providing distribution service as well as earn a regulated rate of return on assets, determined by the regulator, based on the utility's allowed regulated asset base, capital structure, and cost of capital. AES Ohio's retail rates include various adjustment mechanisms including, but not limited to, the timely recovery of costs incurred related to power purchased through the competitive bid process, ##TABLE_START 18 | 2022 Annual Report ##TABLE_ENDparticipation in the PJM RTO, severe storm damage, and energy efficiency. AES Ohio's transmission rates are regulated by FERC. In March 2020, AES Ohio filed an application for a formula-based rate for its transmission service, which was approved and made effective May 3, 2020. In December 2020, an uncontested settlement was reached regarding these rates and filed with the FERC. It was approved on April 15, 2021. AES Ohio is a member of PJM, an RTO that operates the transmission systems owned by utilities operating in all or parts of a multi-state region, including Ohio. PJM also administers the day-ahead and real-time energy markets, ancillary services market and forward capacity market for its members. Ohio law requires utilities to file either an Electric Security Plan ("ESP") or MRO plan to establish SSO rates. On December 18, 2019, the PUCO approved AES Ohio's Notice of Withdrawal and reversion to its prior rate plan (ESP 1). Among other items, the PUCO Order approving the ESP 1 rate plan includes reinstating the non-bypassable RSC Rider, which provides annual revenues of approximately $79 million. The OCC has appealed to the Ohio Supreme Court, the Commissions decision approving the reversion to ESP 1 as well as argued for a refund of the Rate Stabilization Charge ("RSC") revenues dating back to August 2021. A decision is pending. We are unable to predict the outcome of this appeal, but if this results in terms that are more adverse than AES Ohio's current ESP rate plan, it could have a material adverse effect on our results of operations, financial condition and cash flows. On September 26, 2022, AES Ohio filed its latest ESP ("ESP 4") with the PUCO. ESP 4 is a comprehensive plan to enhance and upgrade its network and improve service reliability, provide greater safeguards for price stability and continue investments in local economic development. As part of this plan, AES Ohio intends to increase investments in the distribution infrastructure and deploy a proactive vegetation management program. The plan also includes proposals for new customer programs, including renewable options, electric vehicle programs and energy efficiency programs for residential and low-income customers. ESP 4 also seeks to recover outstanding regulatory assets not currently in rates. AES Ohio did not propose that the Rate Stabilization Charge would continue as part of ESP 4. The plan requires PUCO approval, which we anticipate in 2023. On November 30, 2020, AES Ohio filed a new distribution rate case application with the PUCO to increase AES Ohios base rates for electric distribution service to address, in part, increased costs of materials and labor and substantial investments to improve distribution structures. On December 14, 2022, the PUCO issued an order on the application. Among other matters, the order (i) establishes a revenue increase of $76 million for AES Ohios base rates for electric distribution service and (ii) provides for a return on equity of 9.999% and a cost of long-term debt of 4.4% on a rate base of $783 million and based on a capital structure of 53.87% equity and 46.13% long-term debt. This increase will go into effect when AES Ohio has a new electric security plan in place, which we anticipate in 2023. Smart Grid and Comprehensive Settlement On October 23, 2020, AES Ohio entered into a Stipulation and Recommendation (settlement) with the staff of the PUCO and various customers, and organizations representing customers of AES Ohio and certain other parties with respect to, among other matters, AES Ohio's applications pending at the PUCO for (i) approval of AES Ohio's plan to modernize its distribution grid (the "Smart Grid Plan"), (ii) findings that AES Ohio passed the Significantly Excessive Earnings Test ("SEET") for 2018 and 2019, and (iii) findings that AES Ohio's current ESP 1 satisfies the SEET and the more favorable in the aggregate ("MFA") regulatory test. In June 2021, the PUCO issued their opinion and order accepting the stipulation as filed. With the PUCOs issuance of their opinion and order, AES made cash contributions of $150 million in 2021 to improve AES Ohio's infrastructure and modernize its grid while maintaining liquidity. Several applications for rehearing of the PUCO's orders relating to the comprehensive settlement were filed and denied on December 1, 2021. The OCC appealed this final PUCO Order to the Ohio Supreme Court on December 6, 2021; this appeal remains pending. Separate from the ESP process, on January 23, 2020, AES

Ohio filed with the PUCO requesting approval to defer its decoupling costs consistent with the methodology approved in its Distribution Rate Case. If approved, deferral would be effective December 18, 2019 and going forward would reduce impacts of weather, energy efficiency programs, and economic changes in customer demand. An evidentiary hearing was held on this matter on May 4, 2021. These amounts were also included in the ESP 4 application and are proposed to be recovered in a new rider. Development Strategy Planned construction projects primarily relate to new investments in and upgrades to AES Ohio's transmission and distribution system. Capital projects are subject to continuing review and are revised in light of changes in financial and economic conditions, load forecasts, legislative and regulatory developments, and changing environmental standards, among other factors. ##TABLE_START 19 | 2022 Annual Report ##TABLE_ENDAES Ohio is projecting to spend an estimated $1.2 billion on capital projects from 2023 through 2025, which includes expected spending under AES Ohio's Smart Grid Plan included in the Stipulation and Recommendation entered into in October 2020 (see Regulatory Framework and Market Structure above) as well as other new transmission and distribution projects. The Smart Grid Plan, as approved, provides for a return on and recovery of up to $249 million of Phase 1 investments and recovery of operational and maintenance expenses through AES Ohio's existing Infrastructure Investment Rider for a term of four years, under an aggregate cap of $268 million on the amount of such investments and expenses that is recoverable, and an acknowledgement that AES Ohio may file a subsequent application with the PUCO within three years seeking approvals for Phase 2 of the Smart Grid Plan. AES Ohios spending programs are contingent on successful regulatory outcomes in pending proceedings. AES Clean Energy Business Description AES' U.S. renewables portfolio, referred to as AES Clean Energy, is one of the top U.S. renewables growth platforms. AES Clean Energy aims to solve customers' energy challenges by offering an expanded portfolio of innovative solutions based on cutting-edge technologies that are designed to accelerate their energy futures. The generation capacity of the systems owned and/or operated under AES Clean Energy is 4,919 MW across the U.S., with another 2,862 MW under construction, including 1,707 MW of solar, 639 MW of wind, and 516 MW of energy storage. AES Clean Energy has a 5.2 GW backlog of projects, the majority of which are expected to come online through 2025. The adoption of the Inflation Reduction Act ("IRA") in 2022 is expected to be a significant accelerant to the growth of the U.S. renewables market and AES plans to meet this demand with its 51 GW development pipeline. AES Clean Energy comprises AES Renewable Holdings, sPower, AES Clean Energy Development ("ACED"), and other renewable assets, as part of its broader investments in the U.S. ACED was formed on February 1, 2021, as specifically identified projects in the sPower and AES Renewable Holdings development platforms were merged. ACED serves as the development vehicle for all future renewable projects in the U.S. Following the merger, ACED expanded through the acquisitions of the Valcour Intermediate Holdings wind platform and Community Energy, a U.S. solar developer. AES Clean Energy has also grown organically at a rapid pace and now has more than 1,000 employees, in contrast to less than 500 employees at the time of its formation in 2021. During the same time period, the development pipeline has also more than doubled. In line with AES' strategy of using partnerships to promote the effective deployment of capital, in February 2023, the Company sold 49% of its indirect interest in a 1.3 GW portfolio of sPower's operating assets ("OpCo B") that includes 17 solar projects and one wind project, located across six states, to Hannon Armstrong Sustainable Infrastructure Capital, Inc. Key Financial Drivers The financial results of AES Clean Energy are primarily driven by the efficient construction and operation of renewable energy facilities across the U.S. under long-term PPAs, through which the energy price on the entire production of these facilities is guaranteed. Tax credits associated with the development of U.S. renewables projects can be substantial and have increased with the adoption of the IRA. In 2022, AES recognized $246 million of pre-tax contribution related to the allocation of tax credits to tax equity partners of U.S. renewables projects. The financial results of U.S. renewable assets are primarily driven by the amount of wind or solar resource at the facilities, availability of facilities, growth in projects, and by tax credit recognition once placed in service. A majority of solar projects under AES Clean Energy have been financed with tax equity structures. Under these tax equity structures, the tax equity investors receive a portion of the economic attributes of the facilities, including tax attributes, that vary over the life of the projects. Based on certain liquidation provisions of the tax equity structures, this could result in variability to earnings attributable to AES compared to the earnings reported at the facilities. In 2022, AES Clean Energy largely generated investment tax credits ("ITCs") from its renewable assets. We expect that the extension of the current ITCs and production tax credits ("PTCs"), as well as higher credits available for projects that satisfy wage and apprenticeship requirements under the IRA, will increase demand for our renewable products. Laurel Mountain, Buffalo Gap I, Buffalo Gap II, and Buffalo Gap III are exposed to the volatility of energy prices and their revenue may change materially as energy prices fluctuate in their respective markets of operations. Laurel Mountain also operates 16 MW of battery energy storage that is sold into the PJM market as regulation energy. For these projects, PJM and ERCOT power prices impact financial results. Development Strategy As states, communities, and organizations of all types make commitments and plan to reduce their carbon footprints, renewables are the fastest-growing source of electricity generation in the U.S. AES Clean Energy works with its customers to co-create and deliver the smarter, greener energy solutions that meet ##TABLE_START 20 | 2022 Annual Report ##TABLE_ENDtheir needs, including 24/7 carbon-free energy. For example. AES has worked with several major technology companies to provide clean energy solutions to power their network of data centers. In 2022, AES Clean Energy signed or was awarded 1,990 MW of PPAs. As of December 31, 2022, AES Clean Energy's renewable project backlog includes 5.2 GW of projects for which long-term PPAs have been signed or, as applicable, tariffs have been assigned through a regulatory process. The budget for construction of the projects currently under construction and the contracted projects is over $6 billion. The IRA includes increases, extensions, and/or new tax credits for onshore and offshore wind, solar, storage, and hydrogen projects. These changes in tax policy are supportive of our strategy to grow the AES Clean Energy business through development of our 51 GW U.S. pipeline. To support this growth and address challenges related to a primarily foreign supply chain for solar panels, AES has spearheaded the creation of a U.S. Solar Buyer Consortium, in cooperation with other leading solar companies, with the intent to support the development of U.S. domestic solar manufacturing. AES Clean Energy is actively developing new products and renewable sites to serve the current and future needs of its customers. To further this aim, AES Clean Energy matured its pipeline and expanded it to a total of 51 GW during 2022. U.S. Conventional Generation Business Description In the U.S., we own a conventional generation portfolio. The principal markets and locations where we are engaged in the generation and supply of electricity (energy and capacity) are the California Independent System Operator ("CAISO"), PJM, and Puerto Rico. AES Southland, operating in the CAISO, is our most significant generation business. AES Hawaii previously operated a coal plant under a PPA. The PPA expired and the plant was retired in the third quarter of 2022. Many of our non-renewable U.S. generation plants provide baseload operations and are required to maintain a guaranteed level of availability. Any change in availability has a direct impact on financial performance. Some plants are eligible for availability bonuses if they meet certain requirements. Coal and natural gas are used as the primary fuels. Coal prices are set by market factors internationally, while natural gas prices are generally set domestically. Recently we have seen international impacts on domestic gas prices (Henry Hub) due to the large amount of U.S. natural gas that can be exported through the liquefaction plants that have come online in recent years. Price variations for these fuels can change the composition of generation costs and energy prices in our generation businesses. The generation businesses with PPAs have mechanisms to recover fuel costs from the offtaker, including an energy payment partially based on the market price of fuel. When market price fluctuations in fuel are borne by the offtaker, revenue may change as fuel prices fluctuate, but the variable margin or profitability should remain consistent. These businesses often have an opportunity to increase or decrease profitability from payments under their PPAs depending on such items as plant efficiency and availability, heat rate, and fuel flexibility. Warrior Run currently operates as a QF, as defined under the PURPA. This business entered into a long-term contract with an electric utility that had a mandatory obligation to purchase power from QFs at the utility's avoided cost (i.e. the likely costs for both energy and capital investment that would have been incurred by the purchasing utility if that utility had to provide its own generating capacity or purchase it from another source). To be a QF, a cogeneration facility must produce electricity and useful thermal energy for an industrial or commercial process or heating or cooling application in certain proportions to the facility's total energy output and meet certain efficiency standards. To be a QF, a small power production facility must generally use a renewable resource as its energy input and meet certain size criteria or be a cogeneration facility that simultaneously generates electricity and process heat or steam. Our non-QF generation businesses in the U.S. currently operate as Exempt Wholesale Generators as defined under the Energy Policy Act of 1992, amending the Public Utility Holding Company Act (PUHCA). These businesses, subject to approval of FERC, have the right to sell power at market-based rates, either directly to the wholesale market or to a third-party offtaker such as a power marketer or utility/industrial customer. Under the Energy Policy Act and FERC's regulations, approval from FERC to sell wholesale power at market-based rates is generally dependent upon a showing to FERC that the seller lacks market power in generation and transmission, that the seller and its affiliates cannot erect other barriers to market entry, and that there is no opportunity for abusive transactions involving regulated affiliates of the seller. The U.S. wholesale electricity market consists of multiple distinct regional markets that are subject to both federal regulation, as implemented by FERC, and regional regulation as defined by rules designed and ##TABLE_START 21 | 2022 Annual Report ##TABLE_ENDimplemented by the RTOs, non-profit corporations that operate the regional transmission grid and maintain organized markets for electricity. These rules, for the most part, govern such items as the determination of the market mechanism for setting the system marginal price for energy and the establishment of guidelines and incentives for the addition of new capacity. See Item 1A. Risk Factors for additional discussion on U.S. regulatory matters. AES Southland Business Description AES Southland is one of the largest generation operators in California by aggregate installed capacity, with an installed gross capacity of 3,799 MW at the end of 2022. The five coastal power plants comprising AES Southland are in areas that are critical for local reliability and play an important role in integrating the increasing amounts of renewable generation resources in California. AES Southland is composed of three once-through cooling ("OTC") power plants, two combined cycle gas-fired generation facilities and an interconnected battery-based energy storage facility. Southland Southland comprises AES Huntington Beach, LLC, AES Alamitos, LLC, and AES Redondo Beach ("Southland OTC units"). The Southland OTC units are contracted through Resource Adequacy Purchase Agreements (RAPAs). Under the RAPAs, as approved by the California Public Utilities Commission, these generating stations provide resource adequacy capacity, and have no obligation to produce or sell any energy to the RAPA counterparty. However, the generating stations are required to bid energy into the California ISO markets. Southland OTC units enter into commodity swap contracts to economically hedge price variability inherent in electricity sales arrangements. Compensation under these RAPAs is dependent on the availability of the Southland OTC units in the California ISO market. Failure to achieve the minimum availability target would result in an assessed penalty. The SWRCB OTC Policy previously required the shutdown and permanent retirement of all remaining Southland OTC generating units by December 31, 2020, and there is currently no plan to replace the OTC generating units at the AES Redondo Beach generating station following the retirement. On January 23, 2020, the Statewide Advisory Committee on Cooling Water Intake Structures adopted a recommendation to present to the SWRCB to extend OTC compliance dates for the remaining Southland OTC units at AES Huntington Beach and AES Alamitos until December 31, 2023 and AES Redondo Beach until December 31, 2021. On September 1, 2020, in response to a request by the state's energy, utility, and grid operators and regulators, the SWRCB approved amendments to its OTC. The SWRCB public hearing regarding the final decision on the amendment of the OTC policy was held on October 19, 2021 and the Board voted in favor of extending the compliance date for AES Redondo Beach to December 31, 2023. On September 30, 2022, the Statewide Advisory Committee on Cooling Water Intake Structures approved a recommendation to the SWRCB to consider an extension of the OTC compliance dates for AES Huntington Beach and AES Alamitos to December 31, 2026, in support of grid reliability. The SWRCB staff released a draft OTC Policy amendment on January 31, 2023 to be heard by the SWRCB on March 7, 2023. The final decision from SWRCB is expected during the second half of 2023. See United States Environmental and Land-Use Legislation and Regulations Cooling Water Intake for further discussion of AES Southlands plans regarding the OTC Policy. Southland Energy AES Huntington Beach Energy, LLC, AES Alamitos Energy, LLC, and AES ES Alamitos, LLC (collectively "Southland Energy") each operate under 20-year tolling agreements with Southern California Edison ("SCE") to provide 1,387 MW of combined cycle gas-fired generation (through 2040) and 100 MW of interconnected battery-based energy storage (through 2041). The contracts are RAPAs with annual energy tolling put options. If Southland Energy exercises the annual put option, all capacity, energy and ancillary services will be sold to SCE in exchange for a monthly energy and fixed capacity payment that covers fixed operating cost, debt service, and return on capital. In addition, SCE will reimburse variable costs and provide the natural gas. Southland Energy may exercise the annual put option for any contract year by delivering notice of such exercise to SCE at least one year before the start of such contract year, and no more than two years before the start of any contract year. If the annual put options are not exercised, Southland Energy is required to sell the physical output of the combined cycle gas-fired generation units to AES Integrated Energy. AES Integrated Energy is required to bid energy into the California ISO market. Southland Energy continues to receive the monthly fixed capacity payments for periods when the put option is not exercised. Key Financial Drivers AES Southland's availability is one of the most important drivers of operations, along with market demand and prices for gas and electricity. ##TABLE_START 22 | 2022 Annual Report ##TABLE_ENDPuerto Rico Business Description AES Puerto Rico owns and operates a 524 MW coal-fired cogeneration plant and a 24 MW solar facility representing approximately 8% of the installed capacity in Puerto Rico. Both plants are fully contracted through long-term PPAs with PREPA expiring in 2027 and 2037, respectively. AES Puerto Rico receives a capacity payment based on the plants' twelve month rolling average availability, receiving the full payment when the availability is 90% or higher. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of OperationsKey Trends and UncertaintiesMacroeconomic and

PoliticalPuerto Rico for further discussion of the long-term PPAs with PREPA. Key Financial Drivers Financial results are driven by many factors, including, but not limited to, improved operational performance and plant availability. Regulatory Framework and Market Structure Puerto Rico has a single electric grid managed by PREPA, a state-owned entity that provides virtually all of the electric power consumed in Puerto Rico and generates, transmits, and distributes electricity to 1.5 million customers. Since June 2021, PREPA has contracted LUMA Energy to manage the transmission, distribution and commercialization activities. The Puerto Rico Energy Bureau is the main regulatory body. The bureau approves wholesale and retail rates, sets efficiency and interconnection standards, and oversees PREPA's compliance with Puerto Rico's renewable portfolio standard. Puerto Rico's electricity is 98% produced by thermal plants (48% from petroleum, 33% from natural gas, and 17% from coal), while the remaining 2% is supplied by renewable resources (wind, solar, and hydro). Development Strategy Puerto Rico has clear goals of supplying its system from renewable resources, with targets of 40% from renewables by 2025 and 100% from renewables by 2050. To achieve the established targets, PREPA intends to issue six requests for proposal for generation from renewable sources in the coming years. The first request for proposal was issued on February 22, 2021. AES Puerto Rico, through AES Clean Flexible Energy, is working to deliver green energy solutions to meet the country's needs, with a long-term strategy to achieve 24/7 carbon-free energy. AES Clean Flexible Energy expects to have a portfolio of solar and storage projects participating. As applicable, tariffs will be assigned through a regulatory process. AES Clean Flexible Energy is actively developing new renewable sites to serve the future needs of Puerto Rico and its communities. On August 26, 2022, AES Clean Flexible Energy and PREPA fully executed six contracts (four power purchase and operating agreements and two energy storage service agreements) for a total installed capacity of 245 MW Solar PV and 200 MW-4h Storage. On September 28, 2022, the second auction process was launched by PREPA. U.S. Environmental Regulation For information on compliance with environmental regulations see Item 1. United States Environmental and Land-Use Legislation and Regulations . El Salvador Business Description AES El Salvador is the majority owner of four of the five distribution companies operating in El Salvador (CAESS, CLESA, EEO and DEUSEM). AES El Salvador's territory covers 77% of the country and accounted for 4,042 GWh of the market energy sales during 2022. AES El Salvador owns and operates two solar farms, Opico Power and Moncagua with 4 MW and 3 MW capacity, respectively; AES Nejapa, a biomass power plant with 6 MW capacity; and 50% of Bosforo and Cuscatlan Solar, solar farms with 100 MW and 10 MW capacity, respectively. The energy produced by these solar farms is fully contracted by AES' utilities in El Salvador. In addition, AES El Salvador offers customers non-regulated services such as energy trading, electromechanical construction, OM of electrical assets, EPC, pole rental, and tax collection for municipalities. Key Financial Drivers Financial results are driven by many factors, including, but not limited to: improved operational performance; regulatory outcomes and impacts; variability in energy demand driven by weather; and the impact of fuel oil prices on energy tariff prices, which affect cash flow due to a three-month delay in the pass-through of energy costs to the tariffs charged to customers. Regulatory Framework and Market Structure El Salvador's national electric market is composed of generation, distribution, transmission, and marketing businesses, a market and system operator, and regulatory agencies. The operation of the transmission system and the wholesale market is based on production costs with a ##TABLE_START 23 | 2022 Annual Report ##TABLE_ENDmarginal economic model that rewards efficiency and allows investors to have guaranteed profits, while end users receive affordable rates. The energy sector is governed by the General Electricity Law, which establishes two regulatory entities responsible for monitoring its compliance: The National Energy and Hydrocarbons Direction is the highest authority on energy policy and strategy, and the coordinating body for the different energy sectors. One of its main objectives is to promote investment in non-conventional renewable sources to diversify the energy matrix. The General Superintendence of Electricity and Telecommunications regulates the market and sets consumer prices, and, jointly with the distribution companies in El Salvador, developed the tariff calculation applicable from 2018 until 2022. The tariff calculation was updated during 2022 and will be effective from 2023 until 2027. AES El Salvador distribution rates are regulated by SIGET and are established through a traditional cost-based rate-setting process. AES El Salvador is permitted to recover its costs of providing distribution service as well as earn a regulated rate of return on assets, determined by the regulator, based on the utility's allowed regulated asset base, capital structure, and cost of capital. El Salvador has a national electric grid that interconnects directly with Guatemala and Honduras, allowing transactions with all Central American countries. The sector has approximately 2,250 MW of installed capacity, composed of thermal (56%), hydroelectric (25%), solar (9%), biomass (8%), and wind (2%) generation plants. Development Strategy In order to explore new business opportunities, AES El Salvador created AES Soluciones, an LED public lighting service provider and the main commercial and industrial solar photovoltaic EPC provider in the country. Electromobilty is also being promoted by AES Soluciones through a partnership with Blink Charger in order to design and deploy a private network of electric chargers throughout the country. AES Next, Ltda de. C.V. is the OM services provider for the Bosforo project, as well as a developer of solar MW in El Salvador. Furthermore, the four distribution companies operated by AES El Salvador started a digitization and modernization initiative as part of the development, sustainability, and growth strategy of the business; all aspects of the initiative are on track and in line with targets. ##TABLE_START 24 | 2022 Annual Report ##TABLE_END##TABLE_START (1) Non-GAAP measure. See Item 7. Managements Discussion and Analysis of Financial Condition and Results of Operations SBU Performance AnalysisNon-GAAP Measures for reconciliation and definition. ##TABLE_END##TABLE_START 25 | 2022 Annual Report ##TABLE_ENDSouth America SBU Our South America SBU has generation facilities in four countries Chile,

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Colombia, Argentina, and Brazil. AES Andes is a publicly traded company in Chile and owns all of our assets in Chile and Colombia, as well as the TermoAndes in Argentina, as detailed below. AES has a 99% ownership interest in AES Andes and this business is consolidated in our financial statements. AES Brasil is a publicly traded company in Brazil. AES controls and consolidates AES Brasil through its 48% economic interest. Operating installed capacity of our South America SBU totals 12,950 MW, of which 32%, 26%, 9%, and 33% are located in Argentina, Chile, Colombia, and Brazil, respectively. The following table lists our South America SBU generation facilities: ##TABLE_START 26 | 2022 Annual Report ##TABLE_END##TABLE_START Business Location Fuel Gross MW AES Equity Interest Year Acquired or Began Operation Contract Expiration Date Customer(s) Chivor Colombia Hydro 1,000 99 % 2000 2023-2039 Various San Fernando Colombia Solar 61 99 % 2021 2036 Ecopetrol Brisas Colombia Solar 27 99 % 2022 2037 Ecopetrol Castilla Colombia Solar 21 99 % 2019 2034 Ecopetrol Tunjita Colombia Hydro 20 99 % 2016 2023-2039 Various Colombia Subtotal 1,129 Ventanas (1) Chile Coal 745 99 % 2000, 2010, 2013 Angamos Chile Coal 558 99 % 2011 Various Cochrane Chile Coal 550 57 % 2016 2030-2037 SQM, Sierra Gorda, Quebrada Blanca Alto Maipo (2) Chile Hydro 531 99 % 2021 2040 Minera Los Pelambres Norgener Chile Coal 276 99 % 2000 2028 Codelco Cordillera Hydro Complex (3) Chile Hydro 240 99 % 2000 2023-2024 Various Los Olmos Chile Wind 110 51 % 2022 2032 Google, Various Los Cururos Chile Wind 109 51 % 2019 Various Andes Solar 2a Chile Solar 81 51 % 2021 Google, Various Mesamavida Chile Wind 63 99 % 2022 2038 Google, Various Andes Solar 1 Chile Solar 22 99 % 2016 2036 Quebrada Blanca Cochrane ES Chile Energy Storage 20 57 % 2016 Angamos ES Chile Energy Storage 20 99 % 2011 Laja Chile Biomass 13 99 % 2000 2023 CMPC Norgener ES (Los Andes) Chile Energy Storage 12 99 % 2009 Alfalfal Virtual Reservoir Chile Energy Storage 10 99 % 2020 PFV Kaufmann Chile Solar 1 99 % 2021 2040 Kaufmann Chile Subtotal 3,361 TermoAndes (4) Argentina Gas/Diesel 643 99 % 2000 2023-2024 Various AES Andes Subtotal (5) 5,133 Alicura Argentina Hydro 1,050 100 % 2000 Paran-GT Argentina Gas/Diesel 870 100 % 2001 San Nicols Argentina Coal/Gas/Oil/Energy Storage 691 100 % 1993 Guillermo Brown (6) Argentina Gas/Diesel 576 % 2016 Cabra Corral Argentina Hydro 102 100 % 1995 Various Vientos Bonaerenses Argentina Wind 100 100 % 2020 2024-2040 Various Vientos Neuquinos Argentina Wind 100 100 % 2020 2024-2040 Various Ullum Argentina Hydro 45 100 % 1996 Various Sarmiento Argentina Gas/Diesel 33 100 % 1996 El Tunal Argentina Hydro 10 100 % 1995 Various Argentina Subtotal 3,577 AES Brasil Operaes (Tiet) (7) Brazil Hydro 2,658 48 % 1999 2032 Various Cubico II Brazil Wind 456 48 % 2022 2034-2035 CCEE Alto Serto II Brazil Wind 386 36 % 2017 2033-2035 Various, CCEE Ventus Brazil Wind 187 36 % 2020 2034 CCEE Mandacaru and Salinas Brazil Wind 159 48 % 2021 2033-2034 CCEE Guaimb Brazil Solar 150 36 % 2018 2037 CCEE Tucano (8) Brazil Wind 99 24 % 2022 2042 Unipar AGV Solar Brazil Solar 76 36 % 2019 2039 Various, CCEE Boa Hora Brazil Solar 69 48 % 2019 2035 CCEE AES Brasil Subtotal 4,240 12,950 ##TABLE_END_______________________________ (1) In December 2020, AES

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Andes requested the retirement of Ventanas 2 and is awaiting regulatory approval. (2) In November 2021, Alto Maipo SpA filed a voluntary petition under Chapter 11 of the U.S. Bankruptcy Code. After Chapter 11 filing, the Company no longer has control over Alto Maipo and therefore deconsolidated the business. In May 2022, Alto Maipo emerged from bankruptcy. The restructured business is considered a VIE and the Company continues to account for the business as a deconsolidated entity. (3) Includes: Alfalfal, Queltehues and Volcan. (4) TermoAndes is located in Argentina, but is connected to both the SEN in Chile and the SADI in Argentina. ##TABLE_START 27 | 2022 Annual Report ##TABLE_END(5) In 2022, AES' indirect beneficial interest in AES Andes increased from 67% to 99% as result of a tender offer process. (6) AES operates this facility through management or OM agreements and to date owns no equity interest in the business. (7) Tiet hydro plants: gua Vermelha, Bariri, Barra Bonita, Caconde, Euclides da Cunha, Ibitinga, Limoeiro, Mog-Guau, Nova Avanhandava, Promisso, Sao Joaquim, and Sao Jose. (8) Unconsolidated entity, accounted for as an equity affiliate. Under construction The following table lists our plants under construction in the South America SBU: ##TABLE_START Business Location Fuel Gross MW AES Equity Interest Expected Date of Commercial Operations Mesamvida (1) Chile Wind 5 99 % 1H 2023 Andes Solar 2b (1) Chile Solar 180 99 % 1H 2023 Energy Storage 112 Campo Lindo (1) Chile Wind 73 99 % 1H 2023 Virtual Reservoir 2 Chile Energy Storage 40 99 % 2H 2023 San Matias Chile Wind 82 99 % 1H 2024 Andes Solar 4 Chile Solar 238 99 % 1H 2024 Energy Storage 147 AES Andes Subtotal 877 Tucano Phase 1 Brazil Wind 56 24 % 1H 2023 Tucano Phase 2 Brazil Wind 167 48 % 1H 2023 Cajuna Brazil Wind 325 48 % 1H 2023 Cajuna Brazil Wind 296 36 % 2H 2023 AES Brasil Subtotal 844 1,721 ##TABLE_END_____________________________ (1) AES Andes has contracted to sell 49% ownership interest in each of these projects to Global Infrastructure Partners ("GIP") once they reach commercial operations. Subsequent to the sales, these projects will continue to be consolidated as AES Andes will retain 51% ownership interest. The majority of projects under construction have executed mid- to long-term PPAs. ##TABLE_START 28 | 2022 Annual Report ##TABLE_ENDThe following map illustrates the location of our South America facilities: South America Businesses Chile Business Description In Chile, through AES Andes, we are engaged in the generation and supply of electricity (energy and capacity) in the SENsee Regulatory Framework and Market Structure below. AES Andes is the third largest generation operator in Chile in terms of installed capacity with 3,299 MW, excluding energy storage, and has a market share of approximately 11% as of December 31, 2022. AES Andes owns a diversified generation portfolio in Chile in terms of geography, technology, customers, and energy resources. AES Andes' generation plants are located near the principal electricity consumption centers, including Santiago, Valparaiso, and Antofagasta. AES Andes' diverse generation portfolio provides flexibility for the management of contractual obligations with regulated and unregulated customers, provides backup energy to the spot market and facilitates operations under a variety of market and hydrological conditions. AES Andes' Green Blend strategy aims to reduce carbon intensity and incorporate renewable energy to extend our existing conventional PPAs. This strategy de-links company's PPAs from legacy fossil resources, grows its renewable energy portfolio, and delivers a competitive, reliable energy solution. In line with the Green Blend strategy, AES Andes has committed to not build additional coal-based power plants and to advance the development of new renewable projects, including the implementation of battery energy storage systems ("BESS") and other technological innovations that will provide greater flexibility and reliability to the system. AES Andes currently has long-term contracts, with an average remaining term of approximately 10 years, with regulated distribution companies and unregulated customers, such as mining and industrial companies. In general, these long-term contracts include pass-through mechanisms for fuel costs along with price indexations to U.S. Consumer Price Index ("CPI"). In addition to energy payments, AES Andes also receives capacity payments to compensate for availability during periods of peak demand. The grid operator, Coordinador Electrico Nacional ("CEN"), annually determines the ##TABLE_START 29 | 2022 Annual Report ##TABLE_ENDcapacity requirements for each power plant. The capacity price is fixed semiannually by the National Energy Commission and indexed to the CPI and other relevant indices. Key Financial Drivers Hedging strategies at AES Andes limit volatility to the underlying financial drivers. In addition, financial results are likely to be driven by many factors, including, but not limited to: spot market prices (largely impacted by dry hydrology scenarios, forced outages and international fuel prices); changes in current regulatory rulings altering the ability to pass through or recover certain costs; fluctuations of the Chilean peso; tax policy changes; and legislation promoting renewable energy and/or more restrictive regulations on thermal generation assets. Regulatory Framework and Market Structure The Chilean electricity industry is divided into three business segments: generation, transmission, and distribution. Private companies operate in all three segments, and generators can enter into PPAs to sell energy to regulated and unregulated customers, as well as to other generators in the spot market. Chile operates in a single power market, referred to as the SEN, which is managed by the grid operator CEN. The SEN has an installed capacity of 31,141 MW, and represents 99% of the installed generation capacity of the country. CEN coordinates all generation and transmission companies in the SEN. CEN minimizes the operating costs of the electricity system, while maximizing service quality and reliability requirements. CEN dispatches plants in merit order based on their variable cost of production, allowing for electricity to be supplied at the lowest available cost. In the south-central region of the SEN, thermoelectric generation is required to fulfill demand not satisfied by hydroelectric, solar, and wind output and is critical to provide reliable and dependable electricity supply under dry hydrological conditions in the highest demand area of the SEN. In the northern region of the SEN, which includes the Atacama Desert, thermoelectric capacity represents the majority of installed capacity. The fuels used for thermoelectric generation, mainly coal, diesel, and LNG, are indexed to international prices. In 2022, the installed generation capacity in the Chilean market was composed of 42% thermoelectric, 23% hydroelectric, 20% solar, 13% wind, and 2% other fuel sources. Hydroelectric plants represent a significant portion of the system's installed capacity. Precipitation and snow melt impact hydrological conditions in Chile. Rain occurs principally from June to August and snow melt occurs from September to December. These factors affect dispatch of the system's hydroelectric and thermoelectric generation plants, thereby influencing spot market prices. The Ministry of Energy has primary responsibility for the Chilean electricity system directly or through the National Energy Commission and the Superintendency of Electricity and Fuels. All generators can sell energy through contracts with regulated distribution companies or directly to unregulated customers. Unregulated customers are customers whose connected capacity is higher than 5 MW. Customers with connected capacity between 0.5 MW and 5 MW can opt for regulated or unregulated contracts for a minimum period of four years. By law, both regulated and unregulated customers are required to purchase all electricity under contracts. Generators may also sell energy to other power generation companies on a short-term basis at negotiated prices outside the spot market. Electricity prices in Chile are denominated in USD, although payments are made in Chilean pesos. The Chilean governments decarbonization plan includes the complete retirement of the SEN coal fleet by the end of 2040 and carbon neutrality by 2050. On December 26, 2020, the Ministry of Energys Supreme Decree Number 42 went into effect, allowing coal plants to enter into Strategic Reserve Status (SRS) and receive 60% of capacity payments for the 5-year period following its shutdown to remain connected as a backup in case of a system emergency. Following the issuance of this regulation and per the disconnection and termination agreement signed with the Chilean government in June 2019, AES Andes accelerated the retirement plans of its Ventanas 1 and Ventanas 2 coal-fired units. On July 22, 2022, AES Andes was authorized by the CEN to retire, cease operations, and definitively disconnect Ventanas 1 from the SEN as of June 30, 2022. This coal-fired unit had been in SRS since December 29, 2020. Concurrently, AES Andes requested the shutdown of Ventanas 2 as soon as possible. Ventanas 2s shut down and transition into SRS is pending resolution of current system transmission constraints in order to guarantee system stability and ensure a responsible energy transition. The units retirement ##TABLE_START 30 | 2022 Annual Report ##TABLE_ENDinto SRS has been postponed and is expected to occur during 2023. The definitive cessation of operations of Ventanas 2 is expected by December 29, 2025 as informed by the National Energy Commission on July 22, 2022 through Exempt Resolution No. 555. In July 2021, AES Andes committed to allow the shutdown of coal-fired operations at its Ventanas 3, Ventanas 4, Angamos 1, and Angamos 2 units as soon as January 1, 2025, once the safety, sufficiency, and competitiveness of the system allows it. These four units together have an installed capacity of 1,095 MW and each unit has publicly announced phase-out plans in line with the Companys decarbonization strategy. In July 2021, the Company also sold its entire ownership interest in Guacolda, a 764 MW coal-fired plant located in Chile. Guacolda, Ventanas, and Angamos represent an aggregate of 2.2 GW of coal-fired capacity, or 72% of AES

Andes legacy coal fleet. AES Andes continues to work under the Green Blend strategy to accelerate the phase-out of the remaining two coal-fired plants. Environmental Regulation Chilean law requires all electricity generators to supply a certain portion of their total contractual obligations with non-conventional renewable energy ("NCRE"). Generation companies are able to meet this requirement by building NCRE generation capacity (wind, solar, biomass, geothermal, and small hydroelectric technology) or purchasing NCREs from qualified generators. Non-compliance with the NCRE requirements will result in fines. AES Andes currently fulfills the NCRE requirements by utilizing AES Andes' solar, wind, and biomass power plants. Since 2017, emissions of particulate matter, SO_2, NO_X, and CO_2 are monitored for plants with an installed capacity over 50 MW; these emissions are taxed. In the case of CO_2, the tax is equivalent to $5 per ton emitted. Certain PPAs have clauses allowing the Company to pass the green tax costs to unregulated customers, while some distribution PPAs do not allow for the pass through of these costs. During 2021, the Chilean General Water Direction, as part of the Ministry of Public Works, established the obligation to install and maintain effective monitoring systems for water withdrawal. We are currently implementing these systems in the power plants for which they are required. During 2022, new regulations associated with monitoring requirements were published, including Law 21,455, which is the framework on climate change; the new Ventanas power plant Operational Plan; emission standards for back up generators; and recently enacted Law 21,505, which promotes electric energy storage and electromobility. A Prioritized Program of Standards was published, establishing a set of environmental regulations that will impose new obligations for projects both in operation and under construction, including the regulation of environmental noise, thermoelectric power plant emissions, industrial liquid waste, Green Tax offsets, and environmental quality regulations for the protection of marine waters and sediments of the Quintero-Puchuncav Bay, among others. AES Andes and its subsidiaries are undergoing administrative environmental sanctioning processes. The compliance programs associated with the Ventanas power plant and the Mesamvida wind farm are being executed, and the compliance program associated with the Cochrane power plant is under review by the authority. The Angamos power plant is currently undergoing an environmental review process of the Environmental Qualification Resolution (RCA in Chile). See Item 3. Legal Proceedings of this Form 10-K for further discussion. Development Strategy AES Andes is committed to reducing the coal intensity of the Chilean power grid and plans to increase the renewable energy capacity in its portfolio. As part of this commitment, there are several projects under construction to supply agreements with its main mining customers in execution of the new Green Blend strategy by integrating renewable energy sources into its portfolio, and by providing contracting options that contain a mix of both renewable and nonrenewable solutions. In total, the pipeline currently has 4.2 GW under development at different stages and diversified geographically. Within this portfolio, the Company has made significant progress in the development of NCRE projects that are already contracted. In the Biobo region, the Rinconada wind project (258 MW) is being developed, and in Antofagasta, a new expansion of the Andes Solar power plant is being developed, which will include a battery system to optimize solar generation (186 MW + 186 MW-5hr). In addition, Empresa Elctrica Angamos, a subsidiary of AES Andes, submitted for environmental processing a worldwide pioneering initiative, referred to as the Alba project, that seeks an alternative for the conversion of thermoelectric plants through the use of molten salts. This project explores the possibility of replacing the current coal-fired generation of units 1 and 2 of the Angamos thermoelectric power plant, located in Mejillones, Antofagasta region, with a molten salt system. With this technology, renewable energy is stored as heat to later be used to provide energy and emission-free capacity to the electrical system. ##TABLE_START 31 | 2022 Annual Report ##TABLE_ENDEmpresa Elctrica Angamos is also promoting the advancement of green hydrogen technology for mass production through the Adelaida project, which involves the installation of a low-scale green hydrogen production plant with a capacity of 1,000 kg/day of green hydrogen, equivalent to 2.5 MW of power. Colombia Business Description We operate in Colombia through AES Colombia, a subsidiary of AES Andes, which owns Chivor, a hydroelectric plant with an installed capacity of 1,000 MW and Tunjita, a 20 MW run-of-river hydroelectric plant, both located approximately 160 km east of Bogota, as well as the solar facilities of Castilla, Brisas, and San Fernando, 21 MW, 27 MW, and 61 MW respectively. AES Colombias installed capacity accounted for approximately 6% of system capacity at the end of 2022. AES Colombia is dependent on hydrological conditions, which influence generation and spot prices of non-contracted generation in Colombia. AES Colombia's commercial strategy aims to execute contracts with commercial and industrial customers and bid in public tenders, mainly with distribution companies, in order to reduce margin volatility with proper portfolio risk management. The remaining energy generated by our portfolio is sold to the spot market, including ancillary services. Additionally, AES Colombia receives reliability payments for maintaining the plant's availability and generating firm energy during periods of power scarcity, such as adverse hydrological conditions, in order to prevent power shortages. Key Financial Drivers Hydrological conditions largely influence Chivor's power generation. Maintaining the appropriate contract level, while maximizing revenue through the sale of excess generation, is key to AES Colombia's results of operations. In addition to hydrology, financial results are driven by many factors, including, but not limited to: forced outages; fluctuations of the Colombian peso; and spot market prices. Regulatory Framework and Market Structure Electricity supply in Colombia is concentrated in one main system, the SIN, which encompasses one-third of Colombia's territory, providing electricity to 97% of the country's population. The SIN's installed capacity, primarily hydroelectric (67%), other renewable (3%) and thermal (30%), totaled 18,771 MW as of December 31, 2022. The marked seasonal variations in Colombia's hydrology result in price volatility in the short-term market. In 2022, 84% of total energy demand was supplied by hydroelectric plants. The electricity sector in Colombia operates under a competitive market framework for the generation and sale of electricity, and a regulated framework for transmission and distribution of electricity. The distinct activities of the electricity sector are governed by Colombian laws and CREG, the Colombian regulating entity for energy and gas. Other government entities have a role in the electricity industry, including the Ministry of Mines and Energy, which defines the government's policy for the energy sector; the Public Utility Superintendency of Colombia, which is in charge of overseeing utility companies; and the Mining and Energy Planning Unit, which is in charge of expansion planning of the generation and transmission network. The generation sector is organized on a competitive basis with companies selling their generation in the wholesale market at the short-term price or under bilateral contracts with other participants, including distribution companies, generators and traders, and unregulated customers at freely negotiated prices. The National Dispatch Center dispatches generators in merit order based on bid offers in order to ensure that demand will be satisfied by the lowest cost combination of available generating units. The expansion of the system is supported by two schemes: i) reliability charge auctions where firm energy commitments are focused on conventional technology power plants, and ii) auctions of long-term energy contracts assigned for periods of 15 years aimed at non-conventional renewable resources. Environmental Regulation Decree 1076 of 2015 established the current Environmental Licensing Scheme that defines the scope of the National Environmental Licensing Authority ("ANLA") for granting environmental licenses. In recent years, the Ministry of the Environment has generated regulations in connection with licenses, such as the biotic compensation methodology and guidance for presentation of environmental studies in 2018, and the regulation of minor changes to environmental licenses in 2022. AES Colombia has obtained environmental licenses for 406 MW of wind projects included in its development pipeline. Development Strategy AES Colombia is committed to supporting its customers to diversify their energy supply and become more competitive. As part of this commitment, AES Colombia is developing a pipeline of 1.3 ##TABLE_START 32 | 2022 Annual Report ##TABLE_ENDGW of solar and wind projects. Six wind projects totaling 1,149 MW are located in La Guajira, one of the windiest spots in the world. Of this 1,149 MW, 255 MW were awarded a 15-year PPA at the renewable auction in 2019. Argentina Business Description AES operates plants in Argentina totaling 4,220 MW, representing 10% of the country's total installed capacity. AES owns a diversified generation portfolio in Argentina in terms of geography, technology, and fuel source. AES Argentina's plants are placed in strategic locations within the country in order to provide energy to the spot market and customers, making use of wind, hydro, and thermal plants. AES primarily sells its energy in the wholesale electricity market where prices are largely regulated. In 2022, approximately 84% of the energy was sold in the wholesale electricity market and 16% was sold under contract sales made by TermoAndes, Vientos Neuquinos, and Vientos Bonaerenses power plants. Key Financial Drivers Financial results are driven by many factors, including, but not limited to: forced outages; exposure to fluctuations of the Argentine peso; changes in hydrology and wind resources; timely collection of FONINVEMEM installments and outstanding receivables (see Regulatory Framework and Market Structure below); natural gas prices and availability for contracted generation at TermoAndes; and domestic energy demand and exports. Regulatory Framework and Market Structure Argentina has one main power system, the SADI, which serves 96% of the country. As of December 31, 2022, the installed capacity of the SADI totaled 42,927 MW. The SADI's installed capacity is composed primarily of thermoelectric generation (59%) and hydroelectric generation (26%), as well as wind (8%), nuclear (4%), and solar (3%). Thermoelectric generation in the SADI is primarily natural gas. However, scarcity of natural gas during winter periods (June to August) due to transport constraints result in the use of alternative fuels, such as oil and coal. The SADI is also highly reliant on hydroelectric plants. Hydrological conditions impact reservoir water levels and largely influence the dispatch of the system's hydroelectric and thermoelectric generation plants and, therefore, influence market costs. Precipitation in Argentina occurs principally from May to October. The Argentine regulatory framework divides the electricity sector into generation, transmission, and distribution. The wholesale electric market is comprised of generation companies, transmission companies, distribution companies, and large customers who are permitted to trade electricity. Generation companies can sell their output in the spot market or under PPAs. CAMMESA manages the electricity market and is responsible for dispatch coordination. The Electricity National Regulatory Agency is in charge of regulating public service activities and the Secretariat of Energy regulates system framework and grants concessions or authorizations for sector activities. In Argentina, there is a tolling scheme in which the regulator establishes prices for electricity and defines fuel reference prices. As a result, our businesses are particularly sensitive to changes in regulation. The Argentine electric market is an "average cost" system. Generators are compensated for fixed costs and non-fuel variable costs, under prices denominated in Argentine pesos. CAMMESA is in charge of providing the natural gas and liquid fuels required by the generation companies, except for coal. The expansion of renewable capacity in the system is promoted by allowing the new power plants to sign contracts either with CAMMESA through the RenovAr program or directly by trading energy in the private market. During 2022, although the government increased prices to the end user, subsidies and the system deficit also increased. By December 2022, distribution companies recovered an average 40% of the total cost of the system. In past years, AES Argentina contributed certain accounts receivable to fund the construction of three power plants under FONINVEMEM agreements. These receivables accrue interest and are collected in monthly installments over 10 years after commercial operation date of the related plant takes place. In 2020, FONINVEMEM I and II installments were fully repaid and in 2021 the ownership interests in Termoelctrica San Martn and Termoelctrica Manuel Belgrano were defined after the incorporation of the National Government as majority shareholder. The transfer of the power plants to these companies has not yet occurred. FONINVEMEM III is related to Termoelctrica Guillermo Brown, which commenced operations in April 2016, and the installments are still being collected. AES Argentina will receive a pro rata ownership interest in this plant, which shall not be greater than 30%, ##TABLE_START 33 | 2022 Annual Report ##TABLE_ENDonce the accounts receivables have been fully repaid. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of OperationsCapital Resources and LiquidityLong-Term Receivables and Note 7. Financing Receivables in Item 8. Financial Statements and Supplementary Data of this Form 10-K for further discussion of receivables in Argentina. In 2021 and 2022, the Argentine peso devalued against the USD by approximately 18% and 42%, respectively, and Argentinas economy continued to be highly inflationary. Since September 2019, currency controls have been established to govern the devaluation of the Argentine peso and keep Argentine central bank reserves at acceptable levels. Environmental Regulation Argentina has agreed to commitments made by the international community ratified in the Paris Agreement and in Law 27,270 passed in September 2016. In October 2015, Law 27,191 was passed, seeking to create a successful framework for the development of renewable energy. This law set an objective of 8% renewable energy by 2017 and 20% by 2025 and also introduced tax exemptions for importing equipment used in the construction of renewable energy projects in addition to other tax benefits. This framework fostered AES Argentina's construction of Vientos Bonaerenses and Vientos Neuquinos power plants, which are fully contracted with national and private customers in the long term. In December 2019, Law 27,520 established a minimum budget to grant adequate actions, instruments, and strategies to mitigate and adapt to global climate change effects in all national territories and created the National Office of Climate Change to designate private and public actors to design policies aiming to reduce greenhouse gases and to provide coordinated responses in sectors that are vulnerable to climate change impacts. All AES Argentina plants are certified under international standards of Quality (ISO 9001), Safety and Health (ISO 45.001) and Environment (ISO 14001). Development Strategy Leveraging existing wind operating facilities in southern Buenos Aires and market opportunities, AES Argentina is developing 890 MW of wind greenfield projects that are in mid-to-late stages of development and could be funded locally. These projects are adjacent or nearby to AES Argentina's operating assets and will be used to participate in future private auctions for renewable PPAs. Brazil Business Description AES Brasil owns a diversified generation portfolio in Brazil and its plants are placed in strategic locations within the country in order to provide energy to customers and the regulated market, making use of hydro, solar, and wind generation. AES Brasil owns 12 hydroelectric power plants in the state of So Paulo with total installed capacity of 2,658 MW, which represents approximately 11% of the total generation capacity in the state of So Paulo and 2% of the hydropower physical guarantee of the hydrological risk sharing system (Energy Reallocation Mechanism or "MRE", as described below in the topic " Regulatory Framework and Market Structure"). These hydroelectric plants operate under a 33-year concession expiring in 2032. Over the past three years, AES Brasil acquired and developed three solar power plants in the state of So Paulo, which are fully contracted with 20-year PPAs and together account for 295 MW of installed capacity. AES Brasil has also invested in wind generation which is fully contracted in the regulated market and currently owns the following operational wind complexes: Alto Serto II, located in the state of Bahia with an installed capacity of 386 MW and subject to 20-year PPAs expiring between 2033 and 2035; Ventus, located in the state of Rio Grande do Norte with an installed capacity of 187 MW and subject to a 20-year PPA expiring in 2034; Mandacaru and Salinas, located in the states of Rio Grande do Norte and Cear with 159 MW of installed capacity, fully sold in the regulated market for 20 years; and Ventos do Araripe, Caets, and Cassino, acquired in November 2022 and located in the states of Piaui and Pernambuco, in the northeast region of Brazil, and Rio Grande do Sul in the south region, respectively. The complexes have been operational since 2015 with 456 MW of installed capacity, sold in the regulated market for 20 years. ##TABLE_START 34 | 2022 Annual Report ##TABLE_ENDAES Brasil aims to contract most of its physical guarantee requirements and sell the remaining portion in the spot market. The commercial strategy is reassessed periodically according to changes in market conditions, hydrology, and other factors. AES Brasil generally sells available energy through medium-term bilateral contracts. In the second half of 2020, AES acquired an additional 19.8% ownership in AES Brasil and on December 31, 2020 its economic interest was 44.1%. Through multiple transactions in 2021, AES acquired an additional 1.6% ownership in AES Brasil. Additionally, AES migrated AES Brasil's shares to the Novo Mercado, which is a listing segment of the Brazilian stock exchange with the highest standards of corporate governance in Brazil, requiring equity capital to be composed only of common shares. The reorganization and the exchange of shares was completed on March 26, 2021, and the shares issued by AES Brasil started trading on Novo Mercado on March 29, 2021. The Company maintained majority representation on AES Brasils board of directors. In October 2021, as part of the reorganization process, AES Brasil concluded a follow-on offering for the issuance of 93 million newly issued shares to fund its renewable energy portfolio at a cost of $207 million. As a result, AES' indirect beneficial interest in AES Brasil increased 1%, from 45.7% to 46.7%. In September 2022, AES Brasil commenced a private placement offering for its existing shareholders to subscribe for up to 116 million newly issued shares. The offering concluded on October 3, 2022 with a total of 107 million shares subscribed at a cost of $197 million. AES Holding Brazil acquired 54 million shares, thereby increasing AES indirect beneficial interest in AES Brasil from 46.7% to 47.4%. AES Brasil is reported in the South America SBU reportable segment. Key Financial Drivers The electricity market in Brazil is highly dependent on hydroelectric generation, therefore electricity pricing is driven by hydrology. Plant availability is also a significant financial driver as in times of high hydrology, AES is more exposed to the spot market. AES Brasil's financial results are driven by many factors, including, but not limited to: hydrology, impacting quantity of energy generated in the MRE (see Regulatory Framework and Market Structure below for further information); growth in demand for energy; market price risk when re-contracting; asset management; cost management; and ability to execute on its growth strategy. Regulatory Framework and Market

Structure In Brazil, the Ministry of Mines and Energy determines the maximum amount of energy a generation plant can sell, called physical guarantee, representing the long-term average expected energy production of the plant. Under current rules, physical guarantee energy can be sold to distribution companies through long-term regulated auctions or under unregulated bilateral contracts with large consumers or energy trading companies. Brazil has installed capacity of 191 GW, composed of hydroelectric (58%), thermoelectric (25%), renewable (16%), and nuclear (1%) sources. Operation is centralized and controlled by the national operator, ONS, and regulated by the Brazilian National Electric Energy Agency ("ANEEL"). The ONS dispatches generators based on their marginal cost of production and on the risk of system rationing. Key variables for the dispatch decision are forecasted hydrological conditions, reservoir levels, electricity demand, fuel prices, and thermal generation availability. In case of unfavorable hydrology, the ONS will reduce hydroelectric dispatch to preserve reservoir levels and increase dispatch of thermal plants to meet demand. The consequences of unfavorable hydrology are (i) higher energy spot prices due to higher energy production costs at thermal plants and (ii) the need for hydro plants to purchase energy in the spot market to fulfill their contractual obligations. A mechanism known as the MRE (Energy Reallocation Mechanism) was created under ONS to share hydrological risk across MRE hydro generators by using a generation scaling factor ("GSF") to adjust generators' physical guarantee during periods of hydrological scarcity. If the hydro plants generate less than the total MRE physical guarantee, the hydro generators may need to purchase energy in the short-term market. When total hydro generation is higher than the total MRE physical guarantee, the surplus is proportionally shared among its participants and they may sell the excess energy on the spot market. ##TABLE_START 35 | 2022 Annual Report ##TABLE_ENDIn September 2020, Law 14.052/2020 published by ANEEL was approved by the President, establishing terms for compensation to MRE hydro generators for the incorrect application of the GSF mechanism from 2013 to 2018, which resulted in higher charges assessed to MRE hydro generators by the regulator. Under the law, compensation was in the form of an offer for a concession extension for each hydro generator in exchange for full payment of billed GSF trade payables, the amount of which was reduced in conjunction with the payment for a concession extension. On August 12, 2021, ANEEL published Resolution number 2.919/2021, establishing an extension for the end of the concession originally granted to AES Brasil's hydroelectric plants, from 2029 to 2032. On April 14, 2022, the amended term was finalized and agreed upon by ANEEL and AES. Environmental Regulation In Brazil, the National Environmental Council ("CONAMA") is responsible for environmental licensing procedures. Inspections are performed by authorities at federal, state and municipal levels. The programs developed by AES Brasil are designed to restore and preserve biodiversity and are in compliance with local procedures and the obligations assumed in AES Brasil's concession with the state government. AES Brasil's main environmental projects include a flora management program which guarantees the production of 1 million seedlings of native tree species, a reservoir repopulation program that aims to maintain the ichthyofauna biodiversity and guarantee continuity of fishing activity by riverside communities, a land fauna monitoring and conservation program, and a water quality monitoring program designed to further understand the structure and functioning of aquatic ecosystems. In addition, the monitoring and control of reservoir edges is carried out through continuous inspections by the technical team of the Center of Monitoring of Reservoirs ("CMR") through a system of detection of changes, satellite images, aerophotogrammetric surveys, and field inspections. Development Strategy AES Brasil's strategy is to grow by adding renewable capacity to its generation platform through acquisition or greenfield projects, to focus on client satisfaction and innovation to offer new products and energy solutions, and to be recognized for excellence in asset management. In 2021, AES Brasil acquired the Cajuna wind complexes, 1,485 MW of installed capacity of greenfield wind power projects. Cajuna is comprised of the Santa Tereza, So Ricardo, and Serra Verde complexes located in the states of Rio Grande do Norte and Cear. In March 2022, AES Brasil won the competitive process for the acquisition of the Isolated Productive Unit Cordilheira dos Ventos, which consists of parts of the Facheiro II, Facheiro III, and Laboc projects located in the State of Rio Grande do Norte. These projects have a wind power development capacity of up to 305 MW and were added to the Cajuna wind complex pipeline. Part of Cajuna's capacity is committed under long-term PPAs and in 2022, investment agreements were closed with BRF and Unipar to develop projects of 168 MW and 91 MW, respectively, through joint venture partnerships. In March 2022, AES Brasil acquired Sky Arinos, a solar project with installable capacity of 378 MW in the city of Arinos in the state of Minas Gerais. In November 2022, AES Brasil acquired the Ventos do Araripe, Caets, and Cassino wind complexes, with 456 MW of operational installed capacity located in the states of Piaui and Pernambuco, in the northeast region of Brazil, and Rio Grande do Sul, in the south region. Under the current terms of the 2018 legal agreement in connection with AES Brasil's concession with the state government, AES Brasil is required to increase its capacity in the state of So Paulo by an additional 81 MW by October 2024. On November 30, 2021 AES Brasil acquired AGV Solar VII Geradora de Energia S.A, a special purpose entity with installable capacity of 33 MW of solar generation. AES Brasil continues to pursue new opportunities to achieve the additional capacity. ##TABLE_START 36 | 2022 Annual Report ##TABLE_END##TABLE_START (1) Non-GAAP measure. See Item 7. Managements Discussion and Analysis of Financial Condition and Results of Operations SBU Performance AnalysisNon-GAAP Measures for reconciliation and definition. ##TABLE_END##TABLE_START 37 | 2022 Annual Report ##TABLE_ENDMCAC SBU Our MCAC SBU has a portfolio of generation facilities, including renewable energy, in three countries, with a total capacity of 3,390 MW. Generation The following table lists our MCAC SBU generation facilities: ##TABLE_START Business Location Fuel Gross MW AES Equity Interest Year Acquired or Began Operation Contract Expiration Date Customer(s) DPP (Los Mina) Dominican Republic Gas 358 85 % 1996 2024 Andres, Non-Regulated Users Andres

Ticker: AES, Sector: Utilities, Filed At: 2023-03-01T16:44:29-05:00

(1) Dominican Republic Gas/Diesel 319 85 % 2003 2023-2024 Ede Norte, Ede Este, Ede Sur, Non-Regulated Users Bayasol Dominican Republic Solar 50 85 % 2021 2036 Ede Sur Agua Clara Dominican Republic Wind 50 85 % 2022 2039 Ede Norte Santanasol Dominican Republic Solar 50 85 % 2022 2038 Ede Sur Andres ES Dominican Republic Energy Storage 10 85 % 2017 Los Mina DPP ES Dominican Republic Energy Storage 10 85 % 2017 Dominican Republic Subtotal 847 Merida III Mexico Gas/Diesel 505 75 % 2000 2025 Comision Federal de Electricidad Mesa La Paz (2) Mexico Wind 306 50 % 2019 2045 Fuentes de Energia Peoles Termoelectrica del Golfo (TEG) Mexico Pet Coke 275 99 % 2007 2027 CEMEX Termoelectrica del Penoles (TEP) Mexico Pet Coke 275 99 % 2007 2027 Peoles Mexico Subtotal 1,361 Colon (3) Panama Gas 381 100 % 2018 2028 ENSA, Edemet, Edechi Bayano Panama Hydro 260 49 % 1999 2030 ENSA, Edemet, Edechi, Other Changuinola Panama Hydro 223 90 % 2011 2030 AES Panama Chiriqui-Esti Panama Hydro 120 49 % 2003 2030 ENSA, Edemet, Edechi, Other Penonome I Panama Wind 55 49 % 2020 2023-2030 Altenergy, ENSA, Edement, Edechi Chiriqui-Los Valles Panama Hydro 54 49 % 1999 2030 ENSA, Edemet, Edechi, Other Chiriqui-La Estrella Panama Hydro 48 49 % 1999 2030 ENSA, Edemet, Edechi, Other Pes Solar Panama Solar 10 49 % 2021 2030 ENSA, Edemet, Edechi, Other Mayorca Solar Panama Solar 10 49 % 2021 2030 ENSA, Edemet, Edechi, Other Cedro Panama Solar 10 49 % 2021 2030 ENSA, Edemet, Edechi, Other Caoba Panama Solar 10 49 % 2021 2030 ENSA, Edemet, Edechi, Other 5B Costa Norte Panama Solar 1 100 % 2021 2051 Costa Norte LNG Terminal Panama Subtotal 1,182 3,390 ##TABLE_END_______________________________ (1) Plant also includes an adjacent regasification facility, as well as 70 TBTU LNG storage tank, or an operating capacity of 160,000 m 3 . (2) Unconsolidated entity, accounted for as an equity affiliate. (3) Plant also includes an adjacent regasification facility, as well as an 80 TBTU LNG storage tank, or an operating capacity of 180,000 m 3 . ##TABLE_START 38 | 2022 Annual Report ##TABLE_ENDUnder construction The following table lists our plants under construction in the MCAC SBU 1 : ##TABLE_START Business Location Fuel Gross MW AES Equity Interest Expected Date of Commercial Operations Gatun Panama Gas 670 49 % 2H 2024 Panama Subtotal 670 670 ##TABLE_END_______________________________ (1) Through and equity affiliate, a second LNG storage tank with 50 TBTU of capacity is under construction in the Dominican Republic and expected to come online in 1H 2023. The following map illustrates the location of our MCAC facilities: MCAC Businesses Dominican Republic Business Description AES Dominicana consists of five operating subsidiaries: Andres, Los Mina, Bayasol, Santanasol and Agua Clara. With a total of 847 MW of installed capacity, AES provides 16% of the country's capacity and supplies approximately 22% of the country's energy demand via these generation facilities. 668 MW was predominantly contracted until 2022 with government-owned distribution companies and large customers, and have been contracted back with the distribution companies in January 2023. AES has a strategic partnership with the Estrella and Linda Groups ("Estrella-Linda"), a consortium of two leading Dominican industrial groups that manage

a diversified business portfolio. Andres, Los Mina, Bayasol, Santanasol and Agua Clara are owned 85% by AES. Andres owns and operates a combined cycle natural gas turbine and an energy storage facility with combined generation capacity of 329 MW, as well as the only LNG import terminal in the country, with 160,000 cubic meters of storage capacity. Los Mina owns and operates a combined cycle facility with two natural gas turbines and an energy storage facility with combined generation capacity of 368 MW. Bayasol owns and operates a 50 MW solar farm. Santanasol also operates a 50 MW solar farm. Agua Clara operates a 50 MW wind farm. AES Dominicana has a long-term LNG purchase contract through 1H 2023 for 33.6 trillion btu/year with a price linked to NYMEX Henry Hub. AES Dominicana has entered in a new long-term LNG purchase contract through 1H 2025 to cover the expected dispatch for Andres and Los Mina. Andres has a long-term contract to sell regasified LNG to industrial users and third party power plants within the Dominican Republic, thereby capturing demand from ##TABLE_START 39 | 2022 Annual Report ##TABLE_ENDindustrial and commercial customers and for other power generation companies that had switched their operations to natural gas. Key Financial Drivers Financial results are driven by many factors, including, but not limited to: changes in spot prices due to fluctuations in commodity prices (since fuel is a pass-through cost under the PPAs, any variation in oil prices will impact spot sales for Andres and Los Mina); expiring PPAs, lower contracting levels and the extent of capacity awarded; and growth in domestic natural gas demand, supported by new infrastructure such as the Eastern Pipeline and second LNG tank. Regulatory Framework and Market Structure The Dominican Republic energy market is a decentralized industry consisting of generation, transmission, and distribution businesses. Generation companies can earn revenue through short- and long-term PPAs, ancillary services, and a competitive wholesale generation market. All generation, transmission, and distribution companies are subject to and regulated by the General Electricity Law. Two main agencies are responsible for monitoring compliance with the General Electricity Law: The National Energy Commission drafts and coordinates the legal framework and regulatory legislation. They propose and adopt policies and procedures to implement best practices, support the proper functioning and development of the energy sector, and promote investment. The Superintendence of Electricity's main responsibilities include monitoring compliance with legal provisions, rules, and technical procedures governing generation, transmission, distribution, and commercialization of electricity. They monitor behavior in the electricity market in order to prevent monopolistic practices. In addition to the two agencies responsible for monitoring compliance with the General Electricity Law, the Ministry of Industry and Commerce supervises commercial and industrial activities in the Dominican Republic as well as the fuels and natural gas commercialization to end users. The Dominican Republic has one main interconnected system with 5,110 MW of installed capacity, composed of thermal (72%), hydroelectric (12%), wind (8%), and solar (8%). Development Strategy AES will continue to develop the commercialization of natural gas and incorporate partners directly in gas infrastructure projects. AES partnered with

Energas in a joint venture which has been operating the 50 km Eastern Pipeline since February 2020. The joint venture is also developing an expanded LNG facility of 120,000 cubic meters, including additional storage, regasification, and truck loading capacity, for which the COD is expected in 2023. This will allow AES to reach new customers who have converted, or are in the process of converting, to natural gas as a fuel source, and better operational flexibility. Panama Business Description AES owns and operates five hydroelectric plants totaling 705 MW of generation capacity, a natural gas-fired power plant with 381 MW of generation capacity, a wind farm of 55 MW and four solar plants of 10 MW each, which collectively represent 30% of the total installed capacity in Panama. Furthermore, AES operates an LNG regasification facility, a 180,000 cubic meter storage tank, and a truck loading facility. The majority of our hydroelectric plants in Panama are based on run-of-the-river technology, with the exception of 223 MW Changuinola plant with regulation reservoirs and the 260 MW Bayano plant. Hydrological conditions have an important influence on profitability. Variations in hydrology can result in an excess or a shortfall in energy production relative to our contractual obligations. Hydro generation is generally in a shortfall position during the dry season from January through May, which is offset by thermal and wind generation since its behavior is opposite and complementary to hydro generation. Our hydro and thermal assets are mainly contracted through medium to long-term PPAs with distribution companies. A small volume of our hydro plants are contracted with unregulated users. Our hydro assets in Panama have PPAs with distribution companies expiring up to December 2030 for a total contracted capacity of 377 MW. Our thermal asset in Panama has PPAs with distribution companies for a total contracted capacity of 350 MW expiring in August 2028, which matches the term of the LNG supply agreement of such thermal assets. The LNG supply contract has enough flexibility to divert volumes to the Dominican Republic, which increases the connectivity of our two onshore terminals and allows to optimize the LNG position of the portfolio. Colon LNG Marketing continues developing the LNG market in Latin America, with clients already established in Panama and Colombia. ##TABLE_START 40 | 2022 Annual Report ##TABLE_ENDAdditional efforts deployed in Costa Rica, other Central America regions, and Caribbean islands, mainly focusing on small scale LNG logistics. Key Financial Drivers Financial results are driven by many factors, including, but not limited to: changes in hydrology, which impacts commodity prices and exposes the business to variability in the cost of replacement power; fluctuations in commodity prices, mainly oil and natural gas, which affect the cost of thermal generation and spot prices; constraints imposed by the capacity of transmission lines connecting the west side of the country with the load, keeping surplus power trapped during the rainy season; and country demand as GDP growth is expected to remain strong over the short and medium term. Regulatory Framework and Market Structure The Panamanian power sector is composed of three distinct operating business units: generation, distribution, and transmission. Generators can enter into short-term and long-term PPAs with distributors or unregulated consumers. In addition, generators can enter into backup supply contracts with each other. Outside of PPAs, generators may buy and sell energy in the short-term market. Generators can only contract up to their firm capacity. Three main agencies are responsible for monitoring compliance with the General Electricity Law: The National Secretary of Energy in Panama ("SNE") has the responsibilities of planning, supervising, and controlling policies of the energy sector within Panama. The SNE proposes laws and regulations to the executive agencies that regulate the procurement of energy and hydrocarbons for the country. The National Authority of Public Services ("ASEP") is an autonomous agency of the government. ASEP is responsible for the regulations, control and oversight of public services in Panama, including electricity, the transmission and distribution of natural gas utilities, and the companies that provide such services. The National Dispatch Center ("CND") is in charge of the operation of the system and the management of the electricity market. They are responsible for implementing the economic dispatch of electricity in the wholesale market. The National Dispatch Center's objectives are to minimize the total cost of generation and maintain the reliability and security of the electric power system. Short-term power prices are determined on an hourly basis by the last dispatched generating unit. Physical generation of energy is determined as a result of the optimization of the economic dispatch regardless of contractual arrangements. Panama's current total installed capacity is 3,926 MW, composed of hydroelectric (45%), thermal (37%), wind (7%), and solar (11%) generation. Development Strategy Given our LNG facilitys excess capacity in Panama, the company is developing natural gas supply solutions for third parties such as power generators and industrial and commercial customers. This strategy will support a growing demand for natural gas in the region and will contribute to AES' mission by reducing CO 2 emissions as a result of using LNG. In addition to investing in LNG infrastructure, AES is investing in renewable projects within the region. This will increase complementary non-hydro renewable assets in the system and contribute to the reduction of hydrological risk in Panama. Mexico Business Description AES has 1,361 MW of installed capacity in Mexico. The TEG and TEP pet coke-fired plants, located in Tamuin, San Luis Potosi, supply power to their offtakers under long-term PPAs expiring in 2027 with a 90% availability guarantee. TEG and TEP secure their fuel under a long-term contract. TEG and TEP are in the migration process from the Legacy market to the New Electric Industry law. Merida is a CCGT located on Mexico's Yucatan Peninsula. Merida sells power to the CFE under a capacity and energy based long-term PPA through 2025. Additionally, the plant purchases natural gas and diesel fuel under a long-term contract with one of the CFEs subsidiaries, the cost of which is then passed through to the CFE under the terms of the PPA. Mesa La Paz is a 306 MW wind project developed under a joint venture with Grupo Bal, located in Llera, Tamaulipas. Mesa La Paz sells 82% of its power under long-term PPAs expiring up to 2045. ##TABLE_START 41 | 2022 Annual Report ##TABLE_ENDKey Financial Drivers Financial results are driven by many factors, including, but not limited to: contracting levels, providing additional benefits from improved operational performance, including performance incentives and/or excess energy sales; changes in the methodology to calculate spot energy prices or Locational Marginal Prices, which impacts the excess energy sales to the CFE (see Regulatory Framework and Market Structure below) in (i) TEG and TEP under self-supply scheme, and (ii) Mesa La Paz under the New Market Rules; and improved operational performance and plant availability. Regulatory Framework and Market Structure Mexicos main electrical system is called the National Interconnected System ("SIN"), which geographically covers an area from Puerto Peasco, Sonora to Cozumel, Quintana Roo. Mexico also has three isolated electrical systems: (1) the Baja California Interconnected System, which is interconnected with the western interconnection; (2) the Baja California Sur Interconnected System; and (3) the Muleg Interconnected System, a very small electrical system. All three are isolated from the SIN and from each other. The Mexican power industry comprises the activities of generation, transmission, distribution, and commercialization segments, considering transmission and distribution to be exclusive state services. In addition to the Ministry of Energy, three main agencies are responsible for regulating the market agents and their activities, monitoring compliance with the laws and regulations, and the surveillance of operational compliance and management of the wholesale electricity market: The Energy Regulatory Commission is responsible for the establishment of directives, orders, methodologies, and standards to regulate the electric and fuel markets, as well as granting permits. The National Center for Energy Control, as an ISO, is responsible for managing the wholesale electricity market, transmission and distribution infrastructure, planning network developments, guaranteeing open access to network infrastructure, executing competitive mechanisms to cover regulated demand, and setting transmission charges. The Electricity Federal Commission ("CFE") owns the transmission and distribution grids and is also the country's basic supplier. CFE is the offtaker for IPP generators, and together with its own power units has more than 50% of the current generation market share. Mexico has an installed capacity totaling 86 GW with a generation mix composed of thermal (64%), hydroelectric (15%), wind (8%), solar (7%), and other fuel sources (6%). Development Strategy AES has partnered with Grupo Bal in a joint venture to co-invest in power and related infrastructure projects in Mexico, focusing on renewable generation . ##TABLE_START 42 | 2022 Annual Report ##TABLE_END##TABLE_START (1) Non-GAAP measure. See Item 7. Managements Discussion and Analysis of Financial Condition and Results of Operations SBU Performance AnalysisNon-GAAP Measures for reconciliation and definition. ##TABLE_END##TABLE_START 43 | 2022 Annual Report ##TABLE_ENDEurasia SBU Generation Our Eurasia SBU has generation facilities in five countries with total operating installed capacity of 2,878 MW. The following table lists our Eurasia SBU generation facilities: ##TABLE_START Business Location Fuel Gross MW AES Equity Interest Year Acquired or Began Operation Contract Expiration Date Customer(s) Maritza Bulgaria Coal 690 100 % 2011 2026 NEK St. Nikola Bulgaria Wind 156 89 % 2010 2025 Electricity Security Fund Bulgaria Subtotal 846 Delhi ES India Energy Storage 10 60 % 2019 India Subtotal 10 Amman East (1) Jordan Gas 472 37 % 2009

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2033 National Electric Power Company IPP4 (1) Jordan Gas 250 36 % 2014 2039 National Electric Power Company AM Solar Jordan Solar 48 36 % 2019 2039 National Electric Power Company Jordan Subtotal 770 Netherlands ES Netherlands Energy Storage 10 100 % 2015 Netherlands Subtotal 10 Mong Duong 2 Vietnam Coal 1,242 51 % 2015 2040 EVN Vietnam Subtotal 1,242 2,878 ##TABLE_END_______________________________ (1) Entered into an agreement to sell 26% interest in these businesses in November 2020. ##TABLE_START 44 | 2022 Annual Report ##TABLE_ENDThe following map illustrates the location of our Eurasia facilities: Eurasia Businesses Vietnam Business Description Mong Duong 2 is a 1,242 MW gross coal-fired plant located in the Quang Ninh Province of Vietnam and was constructed under a BOT service concession agreement expiring in 2040. This is the first coal-fired BOT plant using pulverized coal-fired boiler technology in Vietnam. The BOT company has a PPA with EVN and a Coal Supply Agreement with Vinacomin, both expiring in 2040. On December 31, 2020, AES executed an agreement to sell its entire 51% interest in the Mong Duong 2 plant; however, the transaction was not closed by December 31, 2022 and the agreement was terminated by the parties. Key Financial Drivers Financial results are driven by many factors, including, but not limited to, the operating performance and availability of the facility. Regulatory Framework and Market Structure The Ministry of Industry and Trade in Vietnam is primarily responsible for formulating a program to restructure the power industry, developing the electricity market, and promulgating electricity market regulations. The fuel supply is owned by the government through Vinacomin, a state-owned entity, and PetroVietnam. The Vietnam power market is divided into three regions (North, Central, and South), with total installed capacity of approximately 79 GW. The fuel mix in Vietnam is composed primarily of coal (33%), hydropower (28%) and renewables, including solar, wind, and biomass (27%). EVN, the national utility, owns 39% of installed generation capacity. The government is in the process of realigning EVN-owned companies into three different independent operations in order to create a competitive power market. The first stage of this realignment was the implementation of the Competitive Electricity Market, which has been in operation since 2012. The second stage was the introduction of the Electricity Wholesale Market, which has been in operation since the beginning of 2019. The third and final stage impacts the Electricity Retail Market. The reforms are currently in development and pilot implementation is expected around 2024 timeframe. BOT power plants will not directly participate in the power market; alternatively, a single buyer will bid the tariff on the power pool on their behalf. ##TABLE_START 45 | 2022 Annual Report ##TABLE_ENDDevelopment Strategy In Vietnam, we continue to advance the development of our Son My LNG terminal project, which has a design capacity of up to 9.6 million metric tonnes per annum, and the Son My 2 CCGT project, which has a capacity of about 2,250 MW. In October 2019, we received formal approval as a government-mandated investor in the Son My LNG terminal project in partnership with PetroVietnam Gas and in September 2021, we signed the joint venture agreement with PetroVietnam Gas. In April 2022, we, together with our partner PetroVietnam Gas, established Son My LNG Terminal LLC. In September 2019, we received formal approval as the government-mandated investor with 100% equity ownership in the Son My 2 CCGT project and executed a statutory memorandum of understanding with Vietnams Ministry of Industry and Trade in November 2019 to continue developing the Son My 2 CCGT project under Vietnams Build-Operate-Transfer legal framework. The Son My 2 CCGT project will utilize the Son My LNG terminal project and be its anchor customer. Bulgaria Business Description Our AES Maritza plant is a 690 MW lignite fuel thermal power plant. AES Maritza's entire power output is contracted with NEK, the state-owned public electricity supplier, independent energy producer, and trading company. Maritza is contracted under a 15-year PPA that expires in May 2026. AES Maritza is collecting receivables from NEK in a timely manner. However, NEK's liquidity position is subject to political conditions and regulatory changes in Bulgaria. The DG Comp is reviewing NEKs PPA with AES Maritza pursuant to the European Unions state aid rules. AES Maritza believes that its PPA is legal and in compliance with all applicable laws. For additional details see Key Trends and Uncertainties in Item 7. Managements Discussion and Analysis of Financial Condition and Results of Operations in this Form 10-K . AES also owns an 89% economic interest in the St. Nikola wind farm ("Kavarna") with 156 MW of installed capacity. The power output of St. Nikola is sold to customers operating on the liberalized electricity market and the plant may receive additional revenue per the terms of an October 2018 Contract for Premium with the state-owned Electricity System Security Fund. Key Financial Drivers Financial results are driven by many factors, including, but not limited to: regulatory changes in the Bulgarian power market; results of the DG Comp review; availability and load factor of the operating units; the level of wind resources for St. Nikola; spot market price volatility beyond the level of compensation through the Contract for Premium for St. Nikola; and NEK's ability to meet the payment terms of the PPA contract with Maritza. Regulatory Framework and Market Structure The electricity sector in Bulgaria allows both regulated and competitive segments. In its capacity as the public provider of electricity, NEK acts as a single buyer and seller for all regulated transactions on the market. Electricity outside the regulated market trades on one of the platforms of the Independent Bulgarian Electricity Exchange day-ahead market, intra-day market, or bilateral contracts market. Bulgarias power sector is supported by a diverse generation mix, universal access to the grid, and numerous cross-border connections with neighboring countries. In addition, it plays an important role in the energy balance in the southeast European region. In December 2022, Bulgaria implemented Regulation 2022/1854, approved by the European Council in October 2022 as an emergency intervention aiming at limiting energy prices in Europe. The main measure of interest to AES in Bulgaria is the limitation of revenues for "infra-marginal" producers, a category that includes renewables and other technologies which are providing electricity to the grid at a cost below the price level set by the more expensive marginal producers. While the adoption of this regulation has no impact on Maritza power plant, it essentially captures 90% of the incremental margin of Kavarna wind farm since it is now subject to a mandatory cap of 180/MWh on revenues. Bulgaria has 13 GW of installed capacity enabling the country to meet and exceed domestic demand and export energy. Installed capacity is primarily thermal (45%), hydro (25%), and nuclear (16%). Environmental Regulation In July 2020, the EU approved the Next Generation EU ("NGEU") recovery instrument, which aims at mitigating the economic and social impact of the COVID-19 pandemic and making ##TABLE_START 46 | 2022 Annual Report ##TABLE_ENDEuropean economies and societies more sustainable. The main funding component of NGEU is the EUs Recovery and Resilience Facility ("RRF"). In May 2022, the European Commission approved Bulgaria's Recovery and Resilience Plan ("RRP") that describes the reforms and investments which Bulgaria wishes to make with the support of the RRF. In its RRP, Bulgaria commits to designing a coal phase-out plan aiming at retiring coal-fired power plants by 2038. The plan includes a 40% reduction in carbon emissions by the end of 2025 and a ceiling on carbon emissions from 2026 onwards. The mechanism to achieve the target is undefined and the potential impact to Maritza's revenues is expected to be limited. Jordan Business Description In Jordan, AES has a 37% controlling interest in Amman East, a 472 MW oil/gas-fired plant fully contracted with the national utility under a 25-year PPA expiring in 2033, a 36% controlling interest in the IPP4 plant, a 250 MW oil/gas-fired peaker plant fully contracted with the national utility until 2039, and a 36% controlling interest in a 52 MW solar plant fully contracted with the national utility under a 20-year PPA expiring in 2039. We consolidate the results in our operations as we have a controlling interest in these businesses. On November 10, 2020, AES executed a sale and purchase agreement to sell approximately 26% effective ownership interest in both the Amman East and IPP4 plants. The sale is expected to close in 2023 subject to customary approvals, including lender consents. Regulatory Framework and Market Structure The Jordan electricity transmission market is a single-buyer model with the state-owned National Electric Power Company ("NEPCO") responsible for transmission. NEPCO generally enters into long-term PPAs with IPPs to fulfill energy procurement requests from distribution utilities. India AES owns and operates a 10 MW BESS unit in Delhi city, located inside a substation of Tata Power Delhi Distribution Limited ("TPDDL"). The BESS is integrated with the TPDDL distribution system and provides frequency regulation and peak shifting services. ##TABLE_START 47 | 2022 Annual Report ##TABLE_ENDOther Investments Fluence and Uplight are unconsolidated entities and their results are reported as Net equity in earnings of affiliates on our Consolidated Statements of Operations. 5B is accounted for using the measurement alternative and AES will record income or loss only when it receives dividends from 5B or when there is a change in the observable price or an impairment of the investment. Fluence Business Description Fluence, created in 2018 as a joint venture by AES and Siemens, is a global energy storage technology and services company aligned with the AES strategy to drive decarbonization of the electric sector. Fluence is a leading global provider of energy storage products and services and artificial intelligence (AI)-enabled digital applications for renewables and storage. On November 1, 2021, Fluence Energy, Inc. completed its

IPO, generating proceeds of approximately $936 million, after expenses, and is listed on NASDAQ under the symbol "FLNC". AES owns Class B-1 common stock, entitling AES to five votes per share held, and continues to hold its economic interest in the operating subsidiary of Fluence Energy, Inc. AES' economic interest in Fluence is currently 33.5%. The Company continues to account for Fluence as an equity method investment. Key Financial Drivers Fluence's financial results are driven by the growth in its product revenue, an efficient cost structure that is expected to benefit from increased scale, and profit margins on customer contracts. Fluences pipeline of potential projects is global. ##TABLE_START 48 | 2022 Annual Report ##TABLE_ENDRegulatory Framework and Market Structure The grid-connected energy storage sector is expanding rapidly. By incorporating energy storage across the electric power network, utilities and communities around the world will optimize their infrastructure investments, increase network flexibility and resiliency, and accelerate cost-effective integration of renewable electricity generation. According to the BloombergNEF Global Energy Storage Outlook published in October 2022, global annual energy storage capacity installations, excluding residential, grew from approximately 600 MW a year in 2015 to 13 GW a year in 2022 and are expected to grow to 62 GW a year by 2030. Additional growth opportunities exist in the provision of operational and maintenance services associated with energy storage products, as well as the provision of digital applications and solutions to improve performance and economic output. Fluence is positioned to be a leading participant in this growth, with 1.9 GW of energy storage assets deployed and 4.3 GW of contracted backlog, with a gross global pipeline of 9.7 GW as of December 31, 2022. Uplight Business Description The Company holds an equity interest in Uplight as part of its digitization and growth strategy. Uplight offers a comprehensive digital platform for utility customer engagement. Uplight provides software and services to approximately 80 of the leading electric and gas utilities, principally in the U.S., with the mission of motivating and enabling energy users and providers to transition to a clean energy ecosystem. Uplight's solutions form a unified, end-to-end customer energy experience system that delivers innovative energy efficiency, demand response, and clean energy solutions quickly. Utility and energy company leaders rely on Uplight and its customer-focused digital energy experiences to improve customer satisfaction, reduce service costs, increase revenue, and reduce carbon emissions. The Company holds a 29.4% ownership interest in Uplight, which continues to be accounted for as an equity method investment and is reported as part of Corporate and Other. Key Financial Drivers Uplight's financial results are driven by the rate of growth of new customers and the extension of additional services to existing customers. Revenue growth primarily drives its financial results, given the relative significance of fixed operating costs. Development Strategy AES' collaboration with Uplight is designed to create value for Uplight, AES, and their respective customers. AES Indiana and AES Ohio have implemented Uplight's consumer engagement solutions in support of energy efficiency and demand response programs, as well as piloted new solutions with Uplight. 5B Business Description The Company made a strategic investment in 5B, a solar technology innovator with the mission to accelerate the transformation of the world to a clean energy future. 5B's technology design enables solar projects to be installed up to three times faster, while allowing for up to two times more energy within the same footprint and can sustain higher wind speeds than traditional solar plants. Key Financial Drivers 5B is accounted for under the measurement alternative and AES will record income or loss only when it receives dividends from 5B or when there is a change in the observable price or an impairment of the investment. 5B is at the beginning of its growth and is expanding its ecosystem for global reach. Development Strategy In addition to a large global market for third party projects, we believe there is an addressable market of nearly 5 GW across our development pipeline. As of December 31, 2022, 5B has achieved sales orders of 175 MW. AES expects to utilize this technology in conjunction with ongoing automation and digital initiatives to speed up delivery time and lower costs. 5B technology has been deployed at multiple locations in AES including a 2 MW project in Panama and an 11 MW project in Chile, with future deployments expected across markets in the AES portfolio. Environmental and Land-Use Regulations The Company faces certain risks and uncertainties related to numerous environmental laws and regulations, including existing and potential GHG legislation or regulations, and actual or potential laws and regulations pertaining to water discharges, waste management (including disposal of coal combustion residuals), and certain air emissions, such as SO 2 , NO X , particulate matter, mercury, and other hazardous air pollutants. Such risks and uncertainties could result in increased capital expenditures or other compliance costs which could have a material adverse effect on certain of our U.S. or international subsidiaries, and our consolidated results of operations. For further information about these risks, see Item 1A. Risk Factors Our operations are subject to significant ##TABLE_START 49 | 2022 Annual Report ##TABLE_ENDgovernment regulation and could be adversely affected by changes in the law or regulatory schemes; Several of our businesses are subject to potentially significant remediation expenses, enforcement initiatives, private party lawsuits and reputational risk associated with CCR; Our businesses are subject to stringent environmental laws, rules and regulations; and Concerns about GHG emissions and the potential risks associated with climate change have led to increased regulation and other actions that could impact our businesses in this Form 10-K. For a discussion of the laws and regulations of individual countries within each SBU where our subsidiaries operate, see discussion within Item 1. Business of this Form 10-K under the applicable SBUs. Many of the countries in which the Company does business have laws and regulations relating to the siting, construction, permitting, ownership, operation, modification, repair and decommissioning of, and power sales from electric power generation or distribution assets. In addition, international projects funded by the International Finance Corporation, the private sector lending arm of the World Bank, or many other international lenders are subject to World Bank environmental standards or similar standards, which tend to be more stringent than local country standards. The Company often has used advanced generation technologies in order to minimize environmental impacts, such as combined fluidized bed boilers and advanced gas turbines, and environmental control devices such as flue gas desulphurization for SO_2 emissions and selective catalytic reduction for NO_x emissions. Environmental laws and regulations affecting electric power generation and distribution facilities are complex, change frequently, and have become more stringent over time. The Company has incurred and will continue to incur capital costs and other expenditures to comply with these environmental laws and regulations. The Company may be required to make significant capital or other expenditures to comply with these regulations. There can be no assurance that the businesses operated by the subsidiaries of the Company will be able to recover any of these compliance costs from their counterparties or customers such that the Company's consolidated results of operations, financial condition, and cash flows would not be materially affected. Various licenses, permits, and approvals are required for our operations. Failure to comply with permits or approvals, or with environmental laws, can result in fines, penalties, capital expenditures, interruptions, or changes to our operations. Certain subsidiaries of the Company are subject to litigation or regulatory action relating to environmental permits or approvals. See Item 3. Legal Proceedings in this Form 10-K for more detail with respect to environmental litigation and regulatory action. United States Environmental and Land-Use Legislation and Regulations In the United States, the CAA and various state laws and regulations regulate emissions of SO_2 , NO_X , particulate matter, GHGs, mercury, and other hazardous air pollutants. Certain applicable rules are discussed in further detail below. CSAPR CSAPR addresses the "good neighbor" provision of the CAA, which prohibits sources within each state from emitting any air pollutant in an amount which will contribute significantly to any other states nonattainment of, or interference with maintenance of, any NAAQS. The CSAPR required significant reductions in SO_2 and NO_X emissions from power plants in many states in which subsidiaries of the Company operate. The Company is currently required to comply with the CSAPR in Indiana and Maryland. The CSAPR is implemented in part through a market-based program under which compliance may be achievable through the acquisition and use of emissions allowances created by the EPA. The Company complies with CSAPR through operation of existing controls and purchases of allowances on the open market, as needed. In October 2016, the EPA published a final rule to update the CSAPR to address the 2008 ozone NAAQS ("CSAPR Update Rule"). The CSAPR Update Rule found that NO_X ozone season emissions in 22 states (including Indiana and Maryland, and Ohio) affect the ability of downwind states to attain and maintain the 2008 ozone NAAQS, and, accordingly, the EPA issued federal implementation plans that both updated existing CSAPR NO_X ozone season emission budgets for electric generating units within these states and implemented these budgets through modifications to the CSAPR NO_X ozone season allowance trading program. Implementation began in the 2017 ozone season and affected facilities began to receive fewer ozone season NO_X allowances in 2017. Following legal challenges related to the CSAPR Update Rule, on April 30, 2021, EPA issued the Revised CSAPR Update Rule. The Revised CSAPR Update Rule required affected EGUs within certain states (including Indiana and Maryland) to participate in a new trading program, the CSAPR NO x Ozone Season Group 3 trading program. These affected EGUs received fewer ozone season NO x Ozone Season allowances beginning in 2021, which may result in the need for AES affected facilitites to purchase additional allowances. ##TABLE_START 50 | 2022 Annual Report ##TABLE_ENDOn April 6, 2022, the EPA published a proposed Federal Implementation Plan ("FIP") to address air quality impacts with respect to the 2015 Ozone NAAQS. The rule would establish a revised CSAPR NO x Ozone Season Group 3 trading program for 25 states, including Indiana and Maryland. In addition to other requirements, if finalized, EGUs in these states would begin receiving fewer allowances as soon as 2023, which may result in the need to purchase additional allowances. While the Company's additional CSAPR compliance costs to date have been immaterial, the future availability of and cost to purchase allowances to meet the emission reduction requirements is uncertain at this time, but it could be material if certain facilities will need to purchase additional allowances based on reduced allocations. New Source Review ("NSR") The NSR requirements under the CAA impose certain requirements on major emission sources, such as electric generating stations, if changes are made to the sources that result in a significant increase in air emissions. Certain projects, including power plant modifications, are excluded from these NSR requirements if they meet the routine maintenance, repair, and replacement ("RMRR") exclusion of the CAA. There is ongoing uncertainty and significant litigation regarding which projects fall within the RMRR exclusion. Over the past several years, the EPA has filed suits against coal-fired power plant owners and issued NOVs to a number of power plant owners alleging NSR violations. See Item 3. Legal Proceedings in this Form 10-K for more detail with respect to environmental litigation and regulatory action, including an NOV issued by the EPA against AES Indiana concerning NSR and prevention of significant deterioration issues under the CAA. If NSR requirements are imposed on any of the power plants owned by the Company's subsidiaries, the results could have a material adverse impact on the Company's business, financial condition, and results of operations. Regional Haze Rule The EPA's "Regional Haze Rule" established timelines for states to improve visibility in national parks and wilderness areas throughout the United States by establishing reasonable progress goals toward meeting a national goal of natural visibility conditions in Class I areas by the year 2064 through a series of state implementation plans (SIPs), which may result in additional emissions control requirements for electric generating units. SIPs for the first planning period (through 2018) did not result in material impact to AES facilities. For all future SIP planning periods, states must evaluate whether additional emissions reduction measures may be needed to continue making reasonable progress toward natural visibility conditions. The deadline for submittal of the SIP covering the second planning period was July 31, 2021. To date, none of the states in which we operate have submitted plans identifying potential impacts to Company facilities. However, we cannot predict the possible outcome or potential impacts of this matter at this time. NAAQS Under the CAA, the EPA sets NAAQS for six principal pollutants considered harmful to public health and the environment, including ozone, particulate matter, NO_X , and SO_2 , which result from coal combustion. Areas meeting the NAAQS are designated "attainment areas" while those that do not meet the NAAQS are considered "nonattainment areas." Each state must develop a plan to bring nonattainment areas into compliance with the NAAQS, which may include imposing operating limits on individual plants. The EPA is required to review NAAQS at five-year intervals. Based on the current and potential future ambient air standards, certain of the states in which the Company's subsidiaries operate have determined or will be required to determine whether certain areas within such states meet the NAAQS. Some of these states may be required to modify their SIPs to detail how the states will attain or maintain their attainment status. As part of this process, it is possible that the applicable state environmental regulatory agency or the EPA may require reductions of emissions from our generating stations to reach attainment status for ozone, fine particulate matter, NO_X , or SO_2 . The compliance costs of the Company's U.S. subsidiaries could be material. Mercury and Air Toxics Standard In April 2012, the EPAs rule to establish maximum achievable control technology standards for hazardous air pollutants regulated under the CAA emitted from coal and oil-fired electric utilities, known as MATS, became effective and AES facilities implemented measures to comply, as applicable. In June 2015, the U.S. Supreme Court remanded MATS to the D.C. Circuit due to the EPAs failure to consider costs before deciding to regulate power plants under Section 112 of the CAA and subsequently remanded MATS to the EPA without vacatur. On May 22, 2020, the EPA published a final finding that it is not appropriate and necessary to regulate hazardous air pollutant emissions from coal- and oil-fired electric generating units (EGUs) (reversing its prior 2016 finding), but that the EPA would not remove the source category from the CAA Section 112(c) list of source categories and would not change the MATS requirements. Several petitioners filed for judicial review of the final finding and the D.C. Circuit, on February 16, 2021, granted the EPA's request that the rule be held in abeyance pending the EPA's review. On February 9, 2022, the EPA published a proposed rule to revoke its ##TABLE_START 51 | 2022 Annual Report ##TABLE_ENDMay 2020 finding and reaffirm its 2016 finding that it is appropriate and necessary to regulate these emissions. Further rulemakings and/or proceedings are possible; however, in the meantime, MATS remains in effect. We currently cannot predict the outcome of the regulatory or judicial process, or its impact, if any, on our MATS compliance planning or ultimate costs. Greenhouse Gas Emissions In January 2011, the EPA began regulating GHG emissions from certain stationary sources, including a pre-construction permitting program for certain new construction or major modifications, known as the Prevention of Significant Deterioration ("PSD"). If future modifications to our U.S.-based businesses' sources become subject to PSD for other pollutants, it may trigger GHG BACT requirements and the cost of compliance with such requirements may be material. On October 23, 2015, the EPA's rule establishing NSPS for new electric generating units became effective, establishing CO_2 emissions standards for newly constructed coal-fueled electric generating plants, which reflects the partial capture and storage of CO_2 emissions from the plants. The EPA also promulgated NSPS applicable to modified and reconstructed electric generating units, which will serve as a floor for future BACT determinations for such units. The NSPS could have an impact on the Company's plans to construct and/or modify or reconstruct electric generating units in some locations. On December 20, 2018, the EPA published proposed revisions to the final NSPS for new, modified, and reconstructed coal-fired electric utility steam generating units proposing that the best system of emissions reduction for these units is highly efficient generation that would be equivalent to supercritical steam conditions for larger units and sub-critical steam conditions for smaller units, and not partial carbon capture and sequestration, as was finalized in the 2015 final NSPS. The EPA did not include revisions for natural-gas combined cycle or simple cycle units in the December 20, 2018 proposal. In January 2021, the EPA issued a final rule determining when standards are appropriate for GHG emissions from stationary source categories for new source but did not take final action on the 2018 proposal to revise the 2015 final NSPS. On April 5, 2021, the D.C. Circuit vacated and remanded the final January 2021 final rule. Challenges to the GHG NSPS are being held in abeyance at this time. On August 31, 2018, the EPA published in the Federal Register proposed Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units, known as the Affordable Clean Energy (ACE) Rule. On July 8, 2019, the EPA published the final ACE Rule along with associated revisions to implementing regulations. The final ACE Rule established CO_2 emission rules for existing power plants under CAA Section 111(d) and replaced the EPA's 2015 Clean Power Plan Rule (CPP). In accordance with the ACE Rule, the EPA determined that heat rate improvement measures are the best system of emissions reductions for existing coal-fired electric generating units. The final rule required states, including Indiana and Maryland, to develop a State Plan to establish CO_2 emission limits for designated facilities, including AES Indiana Petersburg's and AES Warrior Run's coal-fired electric generating units. States had three years to develop their plans under the rule. However, on January 19, 2021, the D.C. Circuit vacated and remanded to the EPA the ACE Rule, but withheld issuance of the mandate that would effectuate its decision. On February 22, 2021, the D.C. Circuit granted EPA's unopposed motion for a partial stay of the issuance of the mandate on vacating the repeal of the CPP. On March 5, 2021, the D.C. Circuit issued the partial mandate effectuating the vacatur of the ACE Rule. In effect, the CPP did not take effect while the EPA is addressing the remand of the ACE rule by promulgating a new Section 111(d) rule to regulate greenhouse gases from existing electric generating units. On October 29, 2021, the U.S. Supreme Court granted petitions to review the decision by the D.C. Circuit to vacate the ACE Rule. On June 30, 2022, Supreme Court reversed the judgment of the D.C. Circuit Court and remanded for further proceedings consistent with its opinion. The opinion held that the generation shifting approach in the CPP exceeded the authority granted to EPA by Congress under Section 111(d) of the CAA. As a result of the June 30, 2022 Supreme Court decision, on October 27, 2022, the D.C. Circuit recalled its March 5, 2021 partial mandate and issued a new partial mandate holding pending challenges to the ACE Rule in abeyance while EPA develops a replacement rule. The impact of the results of further proceedings and potential future greenhouse gas emissions regulations remains uncertain, but it could be material. The impact of the results of such litigation and potential future greenhouse gas emissions regulations remains uncertain, but it could be material. On January 20, 2021, President Biden signed and submitted an instrument for the U.S. to rejoin the Paris Agreement effective February 19, 2021. In addition, in November 2022, the international community gathered in Egypt at the 27th Conference to the Parties on the UN Framework Convention on Climate Change ("COP27"), during which multiple announcements were made, i ncluding the establishment of a loss and damage fund to support vulnerable countries dealing with the effects of climate change and certain pledges in the area of climate finance. ##TABLE_START 52 | 2022 Annual Report ##TABLE_ENDAs such, there is some uncertainty with respect to the impact of GHG rules. The GHG BACT requirements will not apply at least until we construct a new major source or make a major modification of an existing major source, and the NSPS will not require us to comply with an emissions standard until we construct a new electric generating unit. We do not have any planned major modifications of an existing source or plans to construct a new major source at this time which are expected to be subject to these regulations. Furthermore, the EPA, states, and other utilities are still evaluating potential impacts of the GHG regulations in our industry. In light of these uncertainties, we cannot predict the impact of the EPAs current and future GHG regulations on our consolidated results of operations, cash flows, and financial condition. Due to the future uncertainty of these regulations and associated litigation, we cannot at this time determine the impact on our operations or consolidated financial results, but we believe the cost to comply with a new Section 111(d) Rule, should it be implemented in a prior or a substantially similar form, could be material. The GHG NSPS remains in effect at this time, and, absent further action from the EPA that rescinds or substantively revises the NSPS, it could impact any Company plans to construct and/or modify or reconstruct electric generating units in some locations, which may have a material impact on our business, financial condition, or results of operations. Cooling Water Intake The Company's facilities are subject to a variety of rules governing water use and discharge. In particular, the Company's U.S. facilities are subject to the CWA Section 316(b) rule issued by the EPA effective in 2014 that seeks to protect fish and other aquatic organisms drawn into cooling water systems at power plants and other facilities. These standards require affected facilities to choose among seven BTA options to reduce fish impingement. In addition, certain facilities must conduct studies to assist permitting authorities to determine whether and what site-specific controls, if any, would be required to reduce entrainment of aquatic organisms. It is possible that this process, which includes permitting and public input, could result in the need to install closed-cycle cooling systems (closed-cycle cooling towers), or other technology. Finally, the standards require that new units added to an existing facility to increase generation capacity are required to reduce both impingement and entrainment. It is not yet possible to predict the total impacts of this final rule at this time, including any challenges to such final rule and the outcome of any such challenges. However, if additional capital expenditures are necessary, they could be material. AES Southland's current plan is to comply with the SWRCB OTC Policy by shutting down and permanently retiring all existing generating units at AES Alamitos, AES Huntington Beach, and AES Redondo Beach that utilize OTC by the compliance dates included in the OTC Policy. The SWRCB reviews the implementation plan and latest information on OTC generating unit retirement dates and new generation availability to evaluate the impact on electrical system reliability and OTC compliance dates for specific units. The Companys California subsidiaries have signed 20-year term PPAs with Southern California Edison for the new generating capacity, which have been approved by the California Public Utilities Commission. Construction of new generating capacity began in June 2017 at AES Huntington Beach and July 2017 at AES Alamitos. The new air-cooled combined cycle gas turbine generators and battery energy storage systems were constructed at the AES Alamitos and AES Huntington Beach generating stations. The new air-cooled combined cycle gas turbine generators at the AES Alamitos and AES Huntington Beach generating stations began commercial operation in early 2020 and there is currently no plan to replace the OTC generating units at the AES Redondo Beach generating station following the retirement. Certain OTC units were required to be retired in 2019 to provide interconnection capacity and/or emissions credits prior to startup of the new generating units, and the remaining AES OTC generating units in California will be shutdown and permanently retired by the OTC Policy compliance dates for these units. The SWRCB OTC Policy required the shutdown and permanent retirement of all remaining OTC generating units at AES Alamitos, AES Huntington Beach, and AES Redondo Beach by December 31, 2020. The initial amendment extended the deadline for shutdown and retirement of AES Alamitos and AES Huntington Beachs remaining OTC generating units to December 31, 2023 and extended the deadline for shutdown and retirement of AES Redondo Beachs remaining OTC generating units to December 31, 2021 (the AES Redondo Beach Extension). In October 2020, the cities of Redondo Beach and Hermosa Beach filed a state court lawsuit challenging the AES Redondo Beach Extension. AES opposed the action and the court granted an order dismissing the matter. The case remains open subject to the resolution of counter claims between parties other than AES. Plaintiffs have initiated an additional challenge to the permit, and the outcome of that lawsuit is unclear. On March 16, 2021 the SACCWIS released their draft 2021 report to SWRCB. The report summarizes the State of Californias current electrical grid reliability needs and recommended a two-year extension to the compliance schedule for AES Redondo Beach to address system-wide grid reliability needs. The SWRCB public hearing regarding the final decision on the amendment of the OTC policy was held on October 19, 2021 and the Board voted in favor of extending the compliance date for AES Redondo Beach to December 31, 2023. The AES Redondo Beach NPDES ##TABLE_START 53 | 2022 Annual Report ##TABLE_ENDpermit has been administratively extended. On September 30, 2022, the Statewide Advisory Committee on Cooling Water Intake Structures approved a recommendation to the SWRCB to consider an extension of the OTC compliance dates for AES Huntington Beach, LLC and AES Alamitos, LLC, to December 31, 2026, in support of grid reliability. SWRCB released a draft OTC Policy amendment early in 2023 to be heard by the SWRCB on March 7, 2023. The final decision from SWRCB is expected during the second half of 2023. Power plants are required to comply with the more stringent of state or federal requirements. At present, the California state requirements are more stringent and have earlier compliance dates than the federal EPA requirements, and are therefore applicable to the Company's California assets. Challenges to the federal EPA's rule were filed and consolidated in the U.S. Court of Appeals for the Second Circuit, although implementation of the rule was not stayed while the challenges proceeded. On July 23, 2018, the U.S. Court of Appeals for the Second Circuit upheld the rule. The Second Circuit later denied a petition by environmental groups for rehearing. The Company anticipates that compliance with CWA Section 316(b) regulations and associated costs could have a material impact on our consolidated financial condition or results of operations. Water Discharges In June 2015, the EPA and the U.S. Army Corps of Engineers ("the agencies") published a rule defining federal jurisdiction over waters of the U.S., known as the "Waters of the U.S." (WOTUS) rule. This rule, which initially became effective in August 2015, could expand or otherwise change the number and types of waters or features subject to CWA permitting. However, after repealing the 2015 WOTUS rule on October 22, 2019, the agencies, on April 21, 2020, issued the final Navigable Waters Protection (NWP) rule which again revised the definition of waters of the U.S. On August 30, 2021, the U.S. District Court for the District of Arizona issued an order vacating and remanding the NWP Rule. This vacatur of the NWP Rule applies nationwide. As such, the agencies again interpreted waters of the U.S. consistent with the pre-2015 regulatory regime. On January 18, 2023, the Agencies published a final rule to define the scope of waters regulated under the CWA. The rule restores regulations defining WOTUS that were in place prior to 2015, with updates intended to be consistent with relevant Supreme Court decisions. On January 24, 2022, the U.S. Supreme Court granted certiorari on a wetlands case (Sackett v. EPA) on the limited question of: Whether the Ninth Circuit set forth the proper test for determining whether wetlands are waters of the United States under the Clean Water Act. The Ninth Circuit employed Justice Kennedys significant nexus test from the 2006 Rapanos v. United States decision; the plurality opinion in Rapanos required a water body to have a "continuous surface connection" with a water of the United States in order to be considered a wetland covered by the CWA. In Sackett v. EPA , the Court may finally provide clarity on which test from the 2006 Rapanos decision controls. It is too early to determine whether the newly promulgated NWP rule or any outcome of litigation may have a material impact on our business, financial condition, or results of operations. In November 2015, the EPA published its final ELG rule to reduce toxic pollutants discharged into waters of the U.S. by steam-electric power plants through technology applications. These effluent limitations for existing and new sources include dry handling of fly ash, closed-loop or dry handling of bottom ash, and more stringent effluent limitations for flue gas desulfurization wastewater. AES Indiana Petersburg has installed a dry bottom ash handling system in response to the CCR rule and wastewater treatment systems in response to the NPDES permits in advance of the ELG compliance date. Other U.S. businesses already include dry handling of fly ash and bottom ash and do not generate flue gas desulfurization wastewater. However, it is too early to determine whether any outcome of litigation or current or future revisions to the ELG rule might have a material impact on our business, financial condition, and results of operations. On April 23, 2020, the U.S. Supreme Court issued a decision in the Hawaii Wildlife Fund v. County of Maui case related to whether a CWA permit is required when pollutants originate from a point source but are conveyed to navigable waters through a nonpoint source, such as groundwater. The Court held that discharges to groundwater require a permit if the addition of the pollutants through groundwater is the functional equivalent of a direct discharge from the point source into navigable waters. A number of legal cases relevant to determination of "functional equivalent" are ongoing in various jurisdictions. It is too early to determine whether the Supreme Court decision or the result of litigation to "functional equivalent" may have a material impact on our business, financial condition, or results of operations. Selenium Rule In June 2016, the EPA published the final national chronic aquatic life criterion for the pollutant selenium in fresh water. NPDES permits may be updated to include selenium water quality-based effluent limits based on a site-specific evaluation process, which includes determining if there is a reasonable potential to exceed the revised final selenium water quality standards for the specific receiving water body utilizing actual and/or project discharge information for the generating facilities. As a result, it is not yet possible to predict the total impacts of this final rule at this time, including any challenges to such final rule and the outcome of any such challenges. ##TABLE_START 54 | 2022 Annual Report ##TABLE_ENDHowever, if additional capital expenditures are necessary, they could be material. AES Indiana would seek recovery of these capital expenditures; however, there is no guarantee it would be successful in this regard. Waste Management On October 19, 2015, an EPA rule regulating CCR under the Resource Conservation and Recovery Act as nonhazardous solid waste became effective. The rule established nationally applicable minimum criteria for the disposal of CCR in new and currently operating landfills and surface impoundments, including location restrictions, design and operating criteria, groundwater monitoring, corrective action and closure requirements, and post-closure care. The 2016 Water Infrastructure Improvements for the Nation Act ("WIN Act") includes provisions to implement the CCR rule through a state permitting program, or if the state chooses not to participate, a possible federal permit program. On February 20, 2020, the EPA published a proposed rule to establish a federal CCR permit program that would operate in states without approved CCR permit programs. If this rule is finalized before Indiana or Puerto Rico establishes a state-level CCR permit program, AES CCR units in those locations could eventually be required to apply for a federal CCR permit from the EPA. On December 21, 2022, the Indiana Department of Environmental Management published in the Indiana Register a Second Notice of Comment Period for its proposed CCR rulemaking which would include regulation of CCR through a state permitting program. The EPA has indicated that it will implement a phased approach to amending the CCR Rule, which is ongoing. On August 28, 2020, the EPA published the CCR Part A Rule, that, among other amendments, required certain CCR units to cease waste receipt and initiate closure by April 11, 2021. The CCR Part A Rule also allowed for extensions of the April 11, 2021 deadline if the EPA determines certain criteria are met. Facilities seeking such an extension were required to submit a demonstration to the EPA by November 30, 2020. On January 11, 2022, the EPA released its first in a series of proposed and final determinations regarding nine CCR Part A Rule demonstrations. On April 8, 2022, petitions for review were filed challenging these EPA actions. The petitions are consolidated in Electric Energy, Inc. v. EPA. Also on January 11, 2022,, the EPA issued four compliance-related letters notifying certain other facilities of their compliance obligations under the federal CCR regulations. The determinations and letters include interpretations regarding implementation of the CCR Rule. It is too early to determine the direct or indirect impact of these letters or any determinations that may be made. On January 2, 2020, Puerto Rico Senate Bill 1221 was signed by the Puerto Rico Governor into law and became effective as Act 5-2020. Act 5-2020 prohibits the disposal and unencapsulated beneficial use of CCR and places restrictions on storage of CCR in Puerto Rico. Puerto Rico Department of Natural and Environmental Resources developed implementation regulations which became effective on June 10, 2021. Prior to Act 5-2020's approval, the Company had put in place arrangements to dispose or beneficially use its coal ash and combustion residual outside of Puerto Rico. It is too early to determine whether this might have a material impact on our business, financial condition, and results of operations. The CCR rule, current or proposed amendments to the federal CCR rule or state/territory CCR regulations, the results of groundwater monitoring data, or the outcome of CCR-related litigation could have a material impact on our business, financial condition, and results of operations. AES Indiana would seek recovery of any resulting expenditures; however, there is no guarantee we would be successful in this regard. International Environmental Regulations For a discussion of the material environmental regulations applicable to the Company's businesses located outside of the U.S., see Environmental Regulation under the discussion of the various countries in which the Company's subsidiaries operate in Item 1. Business , under the applicable SBUs. Customers We sell to a wide variety of customers. No individual customer accounted for 10% or more of our 2022 total revenue. In our generation business, we own and/or operate power plants to generate and sell power to wholesale customers such as utilities and other intermediaries. Our utilities sell to end-user customers in the residential, commercial, industrial, and governmental sectors in a defined service area. Human Capital Management At AES, our people are instrumental to helping us meet the worlds energy needs. Supporting our people is a foundational value for AES. All of our actions are grounded in the shared values that shape AES culture: Safety ##TABLE_START 55 | 2022 Annual Report ##TABLE_ENDFirst, Highest Standards, and All Together. The AES Corporation is led and managed by our Chief Executive Officer and the Executive Leadership Team with the guidance and oversight of our Board of Directors. As of December 31, 2022, the Company and its subsidiaries had approximately 9,100 full time/permanent employees. The following chart lists our full time/permanent employees by SBU: As of December 31, 2022, approximately 32% of our U.S. employees were subject to collective bargaining agreements. Collective bargaining agreements between us and these labor unions expire at various dates ranging from 2023 to 2026. In addition, certain employees in non-U.S. locations were subject to collective bargaining agreements, representing approximately 60% of the non-U.S. workforce. Management believes that the Company's employee relations are favorable. Safety At AES, safety is one of our core values. Conducting safe operations at our facilities around the world, so that each person can return home safely, is the cornerstone of our daily activities and decisions. Safety efforts are led by our Chief Operating Officer and supported by safety committees that operate at the local site level. Hazards in the workplace are actively identified and management tracks incidents so remedial actions can be taken to improve workplace safety. AES has established a Safety Management System (SMS) Global Safety Standard that applies to all AES employees, as well as contractors working in AES facilities and construction projects. The SMS requires continuous safety performance monitoring, risk assessment, and performance of periodic integrated environmental, health, and safety audits. The SMS provides a consistent framework for all AES operational businesses and construction projects to set expectations for risk identification and reduction, measure performance, and drive continuous improvements. The SMS standard is consistent with the OHSAS 18001/ISO 45001 standard, and during 2022 approximately 52% of our locations have elected to formally certify their SMS to the OHSAS 18001/ISO 45001 international standard. AES calculates lost time incident (LTI) rates for our employees and contractors based on OSHA standards, based on 200,000 labor hours, which equates to 100 workers who work 40 hours per week and 50 weeks per year. In 2022, there was a 10% decrease in LTI cases. In 2022, AES LTI Rate was 0.162 for AES People, 0.018 for operational contractors, and 0.055 for construction contractors. In 2022, the Company had two contractor work-related fatalities. Talent We believe AES success depends on its ability to attract, develop, and retain key personnel. The skills, experience, and industry knowledge of key employees significantly benefit our operations and performance. We have a comprehensive approach to managing our talent and developing our leaders in order to ensure our people have the right skills for today and tomorrow, whether that requires us to build new business models or leverage leading technologies. ##TABLE_START 56 | 2022 Annual Report ##TABLE_ENDWe emphasize employee development and training. To empower employees, we provide a range of development programs and opportunities, skills, and resources they need to be successful by focusing on experience and exposure, as well as formal programs including our Trainee Program. At AES, we believe that our individual differences make us stronger. Our Diversity and Inclusion Program is led by our Diversity and Inclusion Officer. Governance and standards are guided by the Chief Human Resources Officer, with input from members of the Executive Leadership Team. Compensation AES executive compensation philosophy emphasizes pay-for-performance. Our incentive plans are designed to reward strong performance, with greater compensation paid when performance exceeds expectations and less compensation paid when performance falls below expectations. We invest significant time and resources to ensure our compensation programs are competitive and reward the performance of our people. Every year, AES people who are not part of a collective bargaining agreement are eligible for an annual merit-based salary increase. In addition, individuals are eligible for a salary increase if they receive a significant promotion. For non-collectively bargained employees at certain levels in the organization, we offer annual incentives (bonus) and long-term compensation to reinforce the alignment between AES' employees and AES. Executive Officers The following individuals are our executive officers: Stephen Coughlin, 51 years old, has served as Executive Vice President and Chief Financial Officer since October 2021. Prior to assuming his current position, he led AES Corporate Strategy and Financial Planning teams, and served as the Chair of the Companys Investment Committee. Prior to that role, he served as the Chief Executive Officer of Fluence. Mr. Coughlin joined AES in 2007 and spent his early years with the company leading Financial Planning Analysis for AESs renewables portfolio. Mr. Coughlin is a member of the boards of AES U.S. Investments, Inc., AES U.S. Generation, LLC, and IPALCO. Mr. Coughlin received a bachelor's degree in commerce and finance from the University of Virginia and a Master of Business Administration degree from the University of California at Berkeley. Bernerd Da Santos , 59 years old, has served as Executive Vice President and Chief Operating Officer since December 2017. Previously, Mr. Da Santos held several positions at AES, including Chief Operating Officer and Senior Vice President from 2014 to 2017, Chief Financial Officer, Global Finance Operations from 2012 to 2014, Chief Financial Officer of Global Utilities from 2011 to 2012, Chief Financial Officer of Latin America and Africa from 2009 to 2011, Chief Financial Officer of Latin America from 2007 to 2009, Managing Director of Finance for Latin America from 2005 to 2007, and VP and Controller of La Electricidad de Caracas (EDC) (Venezuela). Prior to joining AES in 2000, Mr. Da Santos held a number of financial leadership positions at EDC. Mr. Da Santos is a member of the boards of AES Brasil Energia S.A., AES Mong Duong Power Co. Ltd., AES Andes, IPALCO, Son My LNG Terminal LLC, AES Renewable Holdings, LLC. Mr. Da Santos holds a bachelors degree with Cum Laude distinction in Business Administration and Public Administration from Universidad Jos Maria Vargas, a bachelors degree with Cum Laude distinction in Business Management and Finance, and an MBA with Cum Laude distinction from Universidad Jos Maria Vargas. Paul L. Freedman , 52 years old, has served as Executive Vice President, General Counsel, and Corporate Secretary since February 2021. Prior to assuming his current position,

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Mr. Freedman was Senior Vice President and General Counsel from February 2018, Corporate Secretary from October 2018, Chief of Staff to the Chief Executive Officer from April 2016 to February 2018, Assistant General Counsel from 2014 to 2016, and from 2007 to 2014 he held a variety of other positions in the AES legal group. Mr. Freedman is a member of the Boards of, AES U.S. Investments, Inc., IPALCO, AES Ohio, AES Southland Energy Holdings, LLC, Business Council for International Understanding, and the Coalition for Integrity. Prior to joining AES, Mr. Freedman was Chief Counsel for credit programs at the U.S. Agency for International Development and he previously worked as an associate at the law firms of White Case and Freshfields. Mr. Freedman received a B.A. from Columbia University and a J.D. from the Georgetown University Law Center. Andrs R. Gluski , 65 years old, has been President, Chief Executive Officer and a member of our Board of Directors since September 2011 and is a member of the Innovation and Technology Committee. Under his leadership, AES has become a world leader in implementing clean technologies, including energy storage and renewable power. Prior to assuming his current position, Mr. Gluski served as Executive Vice President and Chief ##TABLE_START 57 | 2022 Annual Report ##TABLE_ENDOperating Officer of the Company from 2007 to 2011. Prior to that role, he served in a number of senior roles at AES, including as Regional President of Latin America and was Senior Vice President for the Caribbean and Central America. He is a member of the Board of Waste Management and serves as Chairman of the Americas Society/Council of the Americas. Mr. Gluski is a magna cum laude graduate of Wake Forest University and holds an M.A. and a Ph.D. in Economics from the University of Virginia. Tish Mendoza , 47 years old, has served as Executive Vice President and Chief Human Resources Officer since February 2021. Prior to assuming her current position, Ms. Mendoza was Senior Vice President, Global Human Resources and Internal Communications and Chief Human Resources Officer from 2012, Vice President of Human Resources, Global Utilities from 2011 to 2012, Vice President of Global Compensation, Benefits and HRIS, including Executive Compensation, from 2008 to 2011, and acted in the same capacity as the Director of the function from 2006 to 2008. Ms. Mendoza is a member of the boards of IPALCO, Fluence Energy, Inc. and AES Ohio, and sits on AES compensation and benefits committees. Prior to joining AES, Ms. Mendoza was Vice President of Human Resources for a product company in the Treasury Services division of JP Morgan Chase and Vice President of Human Resources and Compensation and Benefits at Vastera, Inc, a former technology and managed services company. Ms. Mendoza earned certificates in Leadership and Human Resource Management, and a bachelors degree in Business Administration and Human Resources. Juan Ignacio Rubiolo , 45 years old, has served as Executive Vice President and President of International Businesses since January 2022. Prior to assuming his current position, Mr. Rubiolo served as Senior Vice President and President of the MCAC SBU from March 2018 to January 2022, as the Chief Executive Officer of AES Mexico from 2014 to March 2018, and as a Vice President of the Commercial team of the MCAC SBU from 2013 to 2014. Mr. Rubiolo joined AES in

2001 and has worked in AES businesses in the Philippines, Argentina, Mexico, Panama, and the Dominican Republic. Mr. Rubiolo serves on the boards of AES Andes, AES Brasil Energia, and AES Colombia Cia S.C.A. E.S.P. Mr. Rubiolo has a Science Degree in Business from the Universidad Austral of Argentina, a Master of Project Management from the Quebec University in Canada and has completed the executive business and leadership program at the University of Virginia. How to Contact AES and Sources of Other Information Our principal offices are located at 4300 Wilson Boulevard, Arlington, Virginia 22203. Our telephone number is (703) 522-1315. Our website address is http://www.aes.com . Our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K and any amendments to such reports filed pursuant to Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934 (the "Exchange Act") are posted on our website. After the reports are filed with, or furnished to the SEC, they are available from us free of charge. Material contained on our website is not part of and is not incorporated by reference in this Form 10-K. The SEC maintains an internet website that contains the reports, proxy and information statements and other information that we file electronically with the SEC at www.sec.gov . Our CEO and our CFO have provided certifications to the SEC as required by Section 302 of the Sarbanes-Oxley Act of 2002. These certifications are included as exhibits to this Annual Report on Form 10-K. Our CEO provided a certification pursuant to Section 303A of the New York Stock Exchange Listed Company Manual on April 28, 2022. Our Code of Business Conduct ("Code of Conduct") and Corporate Governance Guidelines have been adopted by our Board of Directors. The Code of Conduct is intended to govern, as a requirement of employment, the actions of everyone who works at AES, including employees of our subsidiaries and affiliates. Our Ethics and Compliance Department provides training, information, and certification programs for AES employees related to the Code of Conduct. The Ethics and Compliance Department also has programs in place to prevent and detect criminal conduct, promote an organizational culture that encourages ethical behavior and a commitment to compliance with the law, and to monitor and enforce AES policies on corruption, bribery, money laundering and associations with terrorists groups. The Code of Conduct and the Corporate Governance Guidelines are located in their entirety on our website. Any person may obtain a copy of the Code of Conduct or the Corporate Governance Guidelines without charge by making a written request to: Corporate Secretary, The AES Corporation, 4300 Wilson Boulevard, Arlington, VA 22203. If any amendments to, or waivers from, the Code of Conduct or the Corporate Governance Guidelines are made, we will disclose such amendments or waivers on our website. ##TABLE_START 58 | 2022 Annual Report ##TABLE_END ITEM 1A. RISK FACTORS You should consider carefully the following risks, along with the other information contained in or incorporated by reference in this Form 10-K. Additional risks and uncertainties also may adversely affect our business and operations. We routinely encounter and address risks, some of which may cause our future results to be materially different than we presently anticipate. The categories of risk we have identified in Item 1A. Risk Factors include risks associated with our operations, governmental regulation and laws, our indebtedness and financial condition. These risk factors should be read in conjunction with Item 7 . Management's Discussion and Analysis of Financial Condition and Results of Operations in this Form 10-K and the Consolidated Financial Statements and related notes included elsewhere in this Form 10-K. If any of the following events actually occur, our business, financial results and financial condition could be materially adversely affected . Risks Associated with our Operations The operation of power generation, distribution and transmission facilities involves significant risks. We are in the business of generating and distributing electricity, which involves certain risks that can adversely affect financial and operating performance, including: changes in the availability of our generation facilities or distribution systems due to increases in scheduled and unscheduled plant outages, equipment failure, failure of transmission systems, labor disputes, disruptions in fuel supply, poor hydrologic and wind conditions, inability to comply with regulatory or permit requirements, or catastrophic events such as fires, floods, storms, hurricanes, earthquakes, dam failures, tsunamis, explosions, terrorist acts, vandalism, cyber-attacks or other similar occurrences; and changes in our operating cost structure, including, but not limited to, increases in costs relating to gas, coal, oil and other fuel; fuel transportation; purchased electricity; operations, maintenance and repair; environmental compliance, including the cost of purchasing emissions offsets and capital expenditures to install environmental emission equipment; transmission access; and insurance. Our businesses require reliable transportation sources (including related infrastructure such as roads, ports and rail), power sources and water sources to access and conduct operations. The availability and cost of this infrastructure affects capital and operating costs and levels of production and sales. Limitations or interruptions in this infrastructure or at the facilities of our subsidiaries, including as a result of third parties intentionally or unintentionally disrupting this infrastructure or the facilities of our subsidiaries, could impede their ability to produce electricity. In addition, a portion of our generation facilities were constructed many years ago and may require significant capital expenditures for maintenance. The equipment at our plants requires periodic upgrading, improvement or repair and replacement equipment or parts may be difficult to obtain in circumstances where we rely on a single supplier or a small number of suppliers. The inability to obtain replacement equipment or parts, due to disruption of the supply chain or other factors, may impact the ability of our plants to perform. Breakdown or failure of one of our operating facilities may prevent the facility from performing under applicable power sales agreements which, in certain situations, could result in termination of a power purchase or other agreement or incurrence of a liability for liquidated damages and/or other penalties. Power generation involves hazardous activities, including acquiring, transporting and unloading fuel, operating large pieces of rotating equipment and delivering electricity to transmission and distribution systems. In addition to natural risks, such as earthquakes, floods, lightning, hurricanes and wind, hazards, such as fire, explosion, collapse and machinery failure, are inherent risks in our operations which may occur as a result of inadequate internal processes, technological flaws, human error or actions of third parties or other external events. The control and management of these risks depend upon adequate development and training of personnel and on operational procedures, preventative maintenance plans, and specific programs supported by quality control systems, which may not prevent the occurrence and impact of these risks. In addition, our battery storage operations also involve risks associated with lithium-ion batteries. On rare occasions, lithium-ion batteries can rapidly release the energy they contain by venting smoke and flames in a manner that can ignite nearby materials as well as other lithium-ion batteries. While more recent design developments for our storage projects seek to minimize the impact of such events, these events are inherent risks of our battery storage operations. The hazards described above, along with other safety hazards associated with our operations, can cause significant personal injury or loss of life, severe damage to and destruction of property, plant and equipment, contamination of, or damage to, the environment and suspension of operations. The occurrence of any one of these events may result in our being named as a defendant in lawsuits asserting claims for substantial damages, environmental cleanup costs, personal injury and fines and/or penalties. Furthermore, we and our affiliates are parties to material litigation and regulatory proceedings. See Item 3. Legal Proceedings below. There can be no assurance that the outcomes of such matters will not have a material adverse effect on our consolidated financial position. We do a significant amount of business outside the U.S., including in developing countries. A significant amount of our revenue is generated in developing countries and we intend to expand our business in certain developing countries in which AES or its customers have an existing presence. International operations, particularly in developing countries, entail significant risks and uncertainties, including: economic, social and political instability in any particular country or region; adverse changes in currency exchange rates; government restrictions on converting currencies or repatriating funds; unexpected changes in foreign laws and regulations or in trade, monetary, fiscal or environmental policies; high inflation and monetary fluctuations; restrictions on imports of solar panels, wind turbines, coal, oil, gas or other raw materials; threatened or consummated expropriation or nationalization of our assets by foreign governments; unexpected delays in permitting and governmental approvals; unexpected changes or instability affecting our strategic partners in developing countries; failure to comply with the U.S. Foreign Corrupt Practices Act, or other applicable anti-bribery regulations; unwillingness of governments, agencies, similar organizations or other counterparties to honor contracts; unwillingness of governments, government agencies, courts or similar bodies to enforce contracts that are economically advantageous to AES and less beneficial to government or private party counterparties, against those counterparties; inability to obtain access to fair and equitable political, regulatory, administrative and legal systems; adverse changes in government tax policy and tax consequences of operating in multiple jurisdictions;

difficulties in enforcing our contractual rights or enforcing judgments or obtaining a favorable result in local jurisdictions; and inability to attract and retain qualified personnel. Developing projects in less developed economies also entails greater financing risks and such financing may only be available from multilateral or bilateral international financial institutions or agencies that require governmental guarantees for certain project and sovereign-related risks. There can be no assurance that project financing will be available or that, once secured, will provide similar terms or flexibility as would be expected from a commercial lender. Further, our operations may experience volatility in revenues and operating margin caused by regulatory and economic difficulties, political instability and currency devaluations, which may increase the uncertainty of cash flows from these businesses. Any of these factors could have a material, adverse effect on our business, results of operations and financial condition. Our businesses may incur substantial costs and liabilities and be exposed to price volatility as a result of risks associated with the wholesale electricity markets. Some of our businesses sell or buy electricity in the spot markets when they operate at levels that differ from their power sales agreements or retail load obligations or when they do not have any powers sales agreements. Our businesses may also buy electricity in the wholesale spot markets. As a result, we are exposed to the risks of rising and falling prices in those markets. The open market wholesale prices for electricity can be volatile and generally reflect the variable cost of the source generation which could include renewable sources at near zero pricing or ##TABLE_START 60 | 2022 Annual Report ##TABLE_ENDthermal sources subject to fluctuating cost of fuels such as coal, natural gas or oil derivative fuels in addition to other factors described below. Consequently, any changes in the generation supply stack and cost of coal, natural gas, or oil derivative fuels may impact the open market wholesale price of electricity. Volatility in market prices for fuel and electricity may result from, among other things: plant availability in the markets generally; availability and effectiveness of transmission facilities owned and operated by third parties; competition and new entrants; seasonality, hydrology and other weather conditions; illiquid markets; transmission, transportation constraints, inefficiencies and/or availability; renewables source contribution to the supply stack; increased adoption of distributed generation; energy efficiency and demand side resources; available supplies of coal, natural gas, and crude oil and refined products; generating unit performance; natural disasters, terrorism, wars, embargoes, pandemics and other catastrophic events; energy, market and environmental regulation, legislation and policies; general economic conditions that impact demand and energy consumption; and bidding behavior and market bidding rules. Wholesale power prices may experience significant volatility in our markets which could impact our operations and opportunities for future growth. The wholesale prices offered for electricity have been volatile in the markets in which we operate due to a variety of factors, including the increased penetration of renewable generation resources, low-priced natural gas and demand side management. The levelized cost of electricity from new solar and wind generation sources has decreased substantially in recent years as solar panel costs and wind turbine costs have declined, while wind and solar capacity factors have increased. These renewable resources have no fuel costs and very low operational costs , while only operating during certain periods of time (daylight) or weather conditions (higher winds). This, combined with changes in oil, gas, and coal pricing, has led to increasingly volatile electricity markets across our markets. A lso, in many markets, new PPAs have been awarded for renewable generation at prices significantly lower than those awarded just a few years ago. This trend of volatility in wholesale prices could continue and could have a material adverse impact on the financial performance of our existing generation assets to the extent they currently sell or buy power into the spot market to serve our contracts or will seek to sell power into the spot market once our contracts expire. Adverse economic developments in China could have a negative impact on demand for electricity in many of our markets. The Chinese market has been driving global materials demand and pricing for commodities over the past decade. Many of these commodities are produced in our key electricity markets. After experiencing rapid growth for more than a decade, Chinas economy has experienced decreasing foreign and domestic demand, weak investment, factory overcapacity and oversupply in the property market, and has experienced a significant slowdown in recent years. U.S. tariffs have also had a negative impact on China's economic growth. Further, China's Zero COVID strategy contributed to a significant decrease in GDP growth in 2022. The impact of the recent loosening of that strategy is uncertain at this time. Continued slowing in Chinas economic growth, demand for commodities and/or material changes in policy could result in lower economic growth and lower demand for electricity in our key markets, which could have a material adverse effect on our results of operations, financial condition and prospects. We may not have adequate risk mitigation or insurance coverage for liabilities. Power generation, distribution and transmission involves hazardous activities. We may become exposed to significant liabilities for which we may not have adequate risk mitigation and/or insurance coverage. Furthermore, ##TABLE_START 61 | 2022 Annual Report ##TABLE_ENDthrough AGIC, AES captive insurance company, we take certain insurance risk on our businesses. We maintain an amount of insurance protection that we believe is customary, but there can be no assurance it will be sufficient or effective in light of all circumstances, hazards or liabilities to which we may be subject. Our insurance does not cover every potential risk associated with our operations. Adequate coverage at reasonable rates is not always obtainable. In particular, the availability of insurance for coal-fired generation assets has decreased as certain insurers have opted to discontinue or limit offering insurance for such assets. Certain insurers have also withdrawn from insuring hydroelectric assets. We cannot provide assurance that insurance coverage will continue to be available in the amounts or on terms similar to our current policies. In addition, insurance may not fully cover the liability or the consequences of any business interruptions such as natural catastrophes, equipment failure or labor dispute. The occurrence of a significant adverse event not adequately covered by insurance could have a material adverse effect on our business, results or operations, financial condition, and prospects. We may not be able to enter into long-term contracts that reduce volatility in our results. Many of our generation plants conduct business under long-term sales and supply contracts, which helps these businesses to manage risks by reducing the volatility associated with power and input costs and providing a stable revenue and cost structure. In these instances, we rely on power sales contracts with one or a limited number of customers for the majority of, and in some cases all of, the relevant plant's output and revenues over the term of the power sales contract. The remaining terms of the power sales contracts of our generation plants range from one to more than 20 years. In many cases, we also limit our exposure to fluctuations in fuel prices by entering into long-term contracts for fuel with a limited number of suppliers. In these instances, the cash flows and results of operations are dependent on the continued ability of customers and suppliers to meet their obligations under the relevant power sales contract or fuel supply contract, respectively. Some of our long-term power sales agreements are at prices above current spot market prices and some of our long-term fuel supply contracts are at prices below current market prices. The loss of significant power sales contracts or fuel supply contracts, or the failure by any of the parties to such contracts that prevents us from fulfilling our obligations thereunder, could adversely impact our strategy by resulting in costs that exceed revenue, which could have a material adverse impact on our business, results of operations and financial condition. In addition, depending on market conditions and regulatory regimes, it may be difficult for us to secure long-term contracts, either where our current contracts are expiring or for new development projects. The inability to enter into long-term contracts could require many of our businesses to purchase inputs at market prices and sell electricity into spot markets, which may not be favorable. We have sought to reduce counterparty credit risk under our long-term contracts by entering into power sales contracts with utilities or other customers of strong credit quality and by obtaining guarantees from certain sovereign governments of the customer's obligations; however, many of our customers do not have or have not maintained, investment-grade credit ratings. Our generation businesses cannot always obtain government guarantees and if they do, the government may not have an investment grade credit rating. We have also located our plants in different geographic areas in order to mitigate the effects of regional economic downturns; however, there can be no assurance that our efforts will be effective. Our renewable energy projects and other initiatives face considerable uncertainties. Wind, solar, and energy storage projects are subject to substantial risks. Some of these business lines are dependent upon favorable regulatory incentives to support continued investment, and there is significant uncertainty about the extent to which such favorable regulatory incentives will be available in the future. In particular, in the U.S., AES renewable energy generation growth strategy depends in part on federal, state and local government policies and incentives that support the development, financing, ownership and operation of renewable energy generation projects, including investment tax credits, production tax credits, accelerated depreciation, renewable portfolio standards, feed-in-tariffs and similar programs, renewable energy credit mechanisms, and tax exemptions. If these policies and incentives are changed or eliminated, or AES is unable to use them, there could be a material adverse impact on AES U.S. renewable growth opportunities, including fewer future PPAs or lower prices in future PPAs, decreased revenues, reduced economic returns on certain project company investments, increased financing costs, and/or difficulty obtaining financing. In addition, the U.S. Department of Commerces investigation into the antidumping and countervailing duties circumvention claim on solar cells and panels supplied from Malaysia, Vietnam, Thailand, and Cambodia has reached a preliminary determination that circumvention occurred. Additionally, Commerce issued a preliminary determination that circumvention would not be deemed to occur for any solar cells and panels imported from the four countries if the wafers were manufactured outside of China or if no more than two out of six specifically ##TABLE_START 62 | 2022 Annual Report ##TABLE_ENDidentified components were produced in China. These preliminary determinations could be modified and final determinations from Commerce are expected in May 2023. If the final determinations result in additional taxes, tariffs, duties, or other assessments on renewable energy or the equipment necessary to generate or deliver it, such as antidumping and countervailing duty rates, such developments could impede the realization of our U.S. renewables strategy by resulting in, among other items, lack of a satisfactory market for the development and/or financing of our U.S. renewable energy projects, abandoning the development of certain U.S. renewable energy projects, a loss of our investments in the projects, and/or reduced project returns. Furthermore, production levels for our wind and solar projects may be dependent upon adequate wind or sunlight resulting in volatility in production levels and profitability. For our wind projects, wind resource estimates are based on historical experience when available and on wind resource studies conducted by an independent engineer. These wind resource estimates are not expected to reflect actual wind energy production in any given year, but long-term averages of a resource. As a result, these types of projects face considerable risk, including that favorable regulatory regimes expire or are adversely modified. At the development or acquisition stage, our ability to predict actual performance results may be hindered and the projects may not perform as predicted. There are also risks associated with the fact that some of these projects exist in markets where long-term fixed-price contracts for the major cost and revenue components may be unavailable, which in turn may result in these projects having relatively high levels of volatility. These projects can be capital-intensive and generally are designed with a view to obtaining third-party financing, which may be difficult to obtain. As a result, these capital constraints may reduce our ability to develop or obtain third-party financing for these projects. Further, in the U.S., the tax credits associated with certain renewables projects are earned when the project is placed in service. Delays in executing our renewables projects can result in delays in recognizing those tax credits and adversely impact our short-term financial results. Any of the above factors could have a material adverse effect on our business, financial condition, results of operations and prospects. Our development projects are subject to substantial uncertainties. We are in various stages of developing and constructing renewables projects and power plants. Certain of these projects have signed long-term contracts or made similar arrangements for the sale of electricity. Successful completion of the development of these projects depends upon overcoming substantial risks, including risks relating to siting, financing, engineering and construction, permitting, interconnection and transmission, governmental approvals, commissioning delays, supply chain related disruptions to our access to materials, or the potential for termination of the power sales contract as a result of a failure to meet certain milestones. Objections of or challenges by local communities or interest groups may delay or impede permitting for our development projects. In certain cases, our subsidiaries may enter into obligations in the development process even though they have not yet secured financing, PPAs, or other important elements for a successful project. For example, our subsidiaries may instruct contractors to begin the construction process or seek to procure equipment without having financing, a PPA or critical permits in place (or enter into a PPA, procurement agreement or other agreement without agreed financing). If the project does not proceed, our subsidiaries may retain certain liabilities. Furthermore, we may undertake significant development costs and subsequently not proceed with a particular project. We believe that capitalized costs for projects under development are recoverable; however, there can be no assurance that any individual project will reach commercial operation. If development efforts are not successful, we may abandon certain projects, resulting in, writing off the costs incurred, expensing related capitalized development costs incurred and incurring additional losses associated with any related contingent liabilities. Our acquisitions may not perform as expected. Acquisitions have been a significant part of our growth strategy historically and more recently as we grow our renewables business. Although acquired businesses may have significant operating histories, we may have limited or no history of owning and operating certain of these businesses, and possibly limited or no experience operating in the country or region where these businesses are located. We also may encounter challenges in integrating and realizing the expected benefits of these acquisitions as well as integration or other one-time costs that are greater ##TABLE_START 63 | 2022 Annual Report ##TABLE_ENDthan expected. Such businesses may not generate sufficient cash flow to support the indebtedness incurred to acquire them or the capital expenditures needed to develop them; and the rate of return from such businesses may not justify our investment of capital to acquire them. In addition, some of these businesses may have been government owned and some may be operated as part of a larger integrated utility prior to their acquisition. If we were to acquire any of these types of businesses, there can be no assurance that we will be successful in transitioning them to private ownership or that we will not incur unforeseen obligations or liabilities. The COVID-19 pandemic, or the future outbreak of any other highly infectious or contagious diseases, could impact our business and operations. The COVID-19 pandemic has severely impacted global economic activity in recent years, including electricity and energy consumption. COVID-19 or another pandemic could have material and adverse effects on our results of operations, financial condition and cash flows due to, among other factors: further decline in customer demand as a result of general decline in business activity; further destabilization of the markets and decline in business activity negatively impacting customers ability to pay for our services when due or at all, including downstream impacts, whereby the utilities customers are unable to pay monthly bills or receiving a moratorium from payment obligations, resulting in inability on the part of utilities to make payments for power supplied by our generation companies; decline in business activity causing our commercial and industrial customers to experience declining revenues and liquidity difficulties that impede their ability to pay for power that we supply; government moratoriums or other regulatory or legislative actions that limit changes in pricing, delay or suspend customers payment obligations or permit extended payment terms applicable to customers of our utilities or to our offtakers under power purchase agreements, in particular, to the extent that such measures are not mitigated by associated government subsidies or other support to address any shortfall or deficiencies in payments; claims by our PPA counterparties for delay or relief from payment obligations or other adjustments, including claims based on force majeure or other legal grounds; further decline in spot electricity prices; the destabilization of the markets and decline in business activity negatively impacting our customer growth in our service territories at our utilities; negative impacts on the health of our essential personnel and on our operations as a result of implementing stay-at-home, quarantine, curfew and other social distancing measures; delays or inability to access, transport and deliver fuel to our generation facilities due to restrictions on business operations or other factors affecting us and our third-party suppliers; delays or inability to access equipment or the availability of personnel to perform planned and unplanned maintenance or disruptions in supply chain, which can, in turn, lead to disruption in operations; a deterioration in our ability to ensure business continuity, including increased cybersecurity attacks related to the work-from-home environment; further delays to our construction projects, including at our renewables projects, and the timing of the completion of renewables projects; delay or inability to receive the necessary permits for our development projects due to delays or shutdowns of government operations; delays in achieving our financial goals, strategy and digital transformation; deterioration of the credit profile of The AES Corporation and/or its subsidiaries and difficulty accessing the capital and credit markets on favorable terms, or at all, and a severe disruption and instability in the global financial markets, or deterioration in credit and financing conditions, which could affect our access to capital necessary to fund business operations or address maturing liabilities on a timely basis; delays or inability to complete asset sales on anticipated terms or to redeploy capital as set forth in our capital allocation plans; increased volatility in foreign exchange and commodity markets; deterioration of economic conditions, demand and other related factors resulting in impairments to long-lived assets; and ##TABLE_START 64 | 2022 Annual Report ##TABLE_END delay or inability in obtaining regulatory actions and outcomes that could be material to our business, including for recovery of COVID-19 related losses and the review and approval of our rates at our U.S. regulated utilities. The impact of the COVID-19 pandemic also depends on factors, including the effectiveness and timing of updated vaccines to address new variants, the development of more virulent COVID-19 variants as well as third-party actions taken to contain its spread and mitigate its public health effects. A resurgence or material worsening of the COVID-19 pandemic could present material uncertainty that could adversely affect our generation facilities, transmission and distribution systems, development projects, energy storage sales by Fluence, and results of operations, financial condition and cash flows. The COVID-19 pandemic may also heighten many of the other risks described in this section. Competition is increasing and could adversely affect us. The power production markets in which we operate are characterized by numerous strong and capable competitors, many of whom may have extensive and diversified developmental or operating experience (including both domestic and international) and financial resources similar to, or greater than, ours. Further, in recent years, the power production industry has been characterized by strong and increasing competition with respect to both obtaining power sales agreements and acquiring existing power generation assets. In certain markets, these factors have caused reductions in prices contained in new power sales agreements and, in many cases, have caused higher acquisition prices for existing assets through competitive bidding practices. The evolution of competitive electricity markets and the development of highly efficient gas-fired power plants and renewables such as wind and solar have also caused, and could continue to cause, price pressure in certain power markets where we sell or intend to sell power. In addition, the introduction of low-cost disruptive technologies or the entry of non-traditional competitors into our sector and markets could adversely affect our ability to compete, which could have a material adverse effect on our businesses, operating results and financial condition. Supplier and/or customer concentration may expose us to significant financial credit or performance risks. We often rely on a single contracted supplier or a small number of suppliers for the provision of fuel, transportation of fuel and other services required for the operation of some of our facilities. If these suppliers cannot perform, we would seek to meet our fuel requirements by purchasing fuel at market prices, exposing us to market price volatility and the risk that fuel and transportation may not be available during certain periods at any price, which could adversely impact the profitability of the affected business and our results of operations, and could result in a breach of agreements with other counterparties, including, without limitation, offtakers or lenders. Further, our suppliers may source certain materials from areas impacted by the COVID-19 pandemic, which may cause delays and/or disruptions to our development projects or operations. The financial performance of our facilities is dependent on the credit quality of, and continued performance by, suppliers and customers. At times, we rely on a single customer or a few customers to purchase all or a significant portion of a facility's output, in some cases under long-term agreements that account for a substantial percentage of the anticipated revenue from a given facility. Counterparties to these agreements may breach or may be unable to perform their obligations, due to bankruptcy, insolvency, financial distress or other factors. Furthermore, in the event of a bankruptcy or similar insolvency-type proceeding, our counterparty can seek to reject our existing PPA under the U.S. Bankruptcy Code or similar bankruptcy laws, including those in Puerto Rico. We may not be able to enter into replacement agreements on terms as favorable as our existing agreements, and may have to sell power at market prices. A counterparty's breach by of a PPA or other agreement could also result in the breach of other agreements, including the affected businesses debt agreements. Any failure of a supplier or customer to fulfill its contractual obligations could have a material adverse effect on our financial results. We may incur significant expenditures to adapt to our businesses to technological changes. Emerging technologies may be superior to, or may not be compatible with, some of our existing technologies, investments and infrastructure, and may require us to make significant expenditures to remain competitive, or may result in the obsolescence of certain of our operating assets. Our future success will depend, in part, on our ability to anticipate and successfully adapt to technological changes, to offer services and products that meet customer demands and evolving industry standards. Technological changes that could impact our businesses include: ##TABLE_START 65 | 2022 Annual Report ##TABLE_END technologies that change the utilization of electric generation, transmission and distribution assets, including the expanded cost-effective utilization of distributed generation (e.g., rooftop solar and community solar projects), and energy storage technology; advances in distributed and local power generation and energy storage that reduce demand for large-scale renewable electricity generation or impact our customers performance of long-term agreements; and more cost-effective batteries for energy storage, advances in solar or wind technology, and advances in alternative fuels and other alternative energy sources. Emerging technologies may also allow new competitors to more effectively compete in our markets or disintermediate the services we provide our customers, including traditional utility and centralized generation services. If we incur significant expenditures in adapting to technological changes, fail to adapt to significant technological changes, fail to obtain access to important new technologies, fail to recover a significant portion of any remaining investment in obsolete assets, or if implemented technology fails to operate as intended, our businesses, operating results and financial condition could be materially adversely affected. Cyber-attacks and data security breaches could harm our business. Our business relies on electronic systems and network technologies to operate our generation, transmission and distribution infrastructure. We also use various financial, accounting and other infrastructure systems. Our infrastructure may be targeted by nation states, hacktivists, criminals, insiders or terrorist groups. In particular, there has been an increased focus on the U.S. energy grid believed to be related to the Russia/Ukraine conflict. Such an attack, by hacking, malware or other means, may interrupt our operations, cause property damage, affect our ability to control our infrastructure assets, cause the release of sensitive customer information or limit communications with third parties. Any loss or corruption of confidential or proprietary data through a breach may: impact our operations, revenue, strategic objectives, customer and vendor relationships; expose us to legal claims and/or regulatory investigations and proceedings; require extensive repair and restoration costs for additional security measures to avert future attacks; impair our reputation and limit our competitiveness for future opportunities; and impact our financial and accounting systems and, subsequently, our ability to correctly record, process and report financial information. We have implemented measures to help prevent unauthorized access to our systems and facilities, including certain measures to comply with mandatory regulatory reliability standards. To date, cyber-attacks have not had a material impact on our operations or financial results. We continue to assess potential threats and vulnerabilities and make investments to address them, including global monitoring of networks and systems, identifying and implementing new technology, improving user awareness through employee security training, and updating our security policies as well as those for third-party providers. We cannot guarantee the extent to which our security measures will prevent future cyber-attacks and security breaches or that our insurance coverage will adequately cover any losses we may experience. Further, we do not control certain of joint ventures or our equity method investments and cannot guarantee that their efforts will be effective. Certain of our businesses are sensitive to variations in weather and hydrology. Our businesses are affected by variations in general weather patterns and unusually severe weather. Our businesses forecast electric sales based on best available information and expectations for weather, which represents a long-term historical average. While we also consider possible variations in normal weather patterns and potential impacts on our facilities and our businesses, there can be no assurance that such planning can prevent these impacts, which can adversely affect our business. Generally, demand for electricity peaks in winter and summer. Typically, when winters are warmer than expected and summers are cooler than expected, demand for energy is lower, resulting in less demand for electricity than forecasted. Significant variations from normal weather where our businesses are located could have a material impact on our results of operations. Changes in weather can also affect the production of electricity at power generation facilities, including, but not limited to, our wind and solar facilities. For example, the level of wind resource affects the revenue produced by wind generation facilities. Because the levels of wind and solar resources are variable and difficult to predict, our results of operations for individual wind and solar facilities specifically, and our results of operations generally, may vary significantly from period to period, depending on the level of available resources. To the extent that resources are not available at planned levels, the financial results from these facilities may be less than expected. In addition, ##TABLE_START 66 | 2022 Annual Report ##TABLE_ENDwe are dependent upon hydrological conditions prevailing from time to time in the broad geographic regions in which our hydroelectric generation facilities are located. Changes in temperature, precipitation and snow pack conditions also could affect the amount and timing of hydroelectric generation. To the extent that hydrological conditions result in droughts or other conditions negatively affect our hydroelectric generation business, such as has happened in Panama in 2019 and Brazil in 2021, our results of operations can be materially adversely affected. Additionally, our contracts in certain markets where hydroelectric facilities are prevalent may require us to purchase power in the spot markets when our facilities are unable to operate at anticipated levels and the price of such spot power may increase substantially in times of low hydrology. Severe weather and natural disasters may present significant risks to our business. Weather conditions directly influence the demand for electricity and natural gas and other fuels and affect the price of energy and energy-related commodities. In addition, severe weather and natural disasters, such as hurricanes, floods, tornadoes, icing events, earthquakes, dam failures and tsunamis can be destructive and could prevent us from operating our business in the normal course by causing power outages and property damage, reducing revenue, affecting the availability of fuel and water, causing injuries and loss of life, and requiring us to incur additional costs, for example, to restore service and repair damaged facilities, to obtain replacement power and to access available financing sources. Our power plants could be placed at greater risk of damage should changes in the global climate produce unusual variations in temperature and weather patterns, resulting in more intense, frequent and extreme weather events, including heatwaves, fewer cold temperature extremes, abnormal levels of precipitation resulting in river and coastal urban floods in North America or reduced water availability and increased flooding across Central and South America, and changes in coast lines due to sea level change. Depending on the nature and location of the facilities and infrastructure affected, any such incident also could cause catastrophic fires; releases of natural gas, natural gas odorant, or other greenhouse gases; explosions, spills or other significant damage to natural resources or property belonging to third parties; personal injuries, health impacts or fatalities; or present a nuisance to impacted communities. Such incidents may also impact our business partners, supply chains and transportation, which could negatively impact construction projects and our ability to provide electricity and natural gas to our customers. A disruption or failure of electric generation, transmission or distribution systems or natural gas production, transmission, storage or distribution systems in the event of a hurricane, tornado or other severe weather event, or otherwise, could prevent us from operating our business in the normal course and could result in any of the adverse consequences described above. At our businesses where cost recovery is available, recovery of costs to restore service and repair damaged facilities is or may be subject to regulatory approval, and any determination by the regulator not to permit timely and full recovery of the costs incurred. Any of the foregoing could have a material adverse effect on our business, financial condition, results of operations, reputation and prospects. We do not control certain aspects of our joint ventures or our equity method investments. We have invested in some joint ventures in which our subsidiaries share operational, management, investment and/or other control rights with our joint venture partners. In many cases, we may exert influence over the joint venture pursuant to a management contract, by holding positions on the board of the joint venture company or on management committees and/or through certain limited governance rights, such as rights to veto significant actions. However, we do not always have this type of influence over the project or business and we may be dependent on our joint venture partners or the management team of the joint venture to operate, manage, invest or otherwise control such projects or businesses. Our joint venture partners or the management team of our joint ventures may not have the level of experience, technical expertise, human resources, management and other attributes necessary to operate these projects or businesses optimally, and they may not share our business priorities. In some joint venture agreements in which we do have majority control of the voting securities, we have entered into shareholder agreements granting minority rights to the other shareholders. The approval of joint venture partners also may be required for us to receive distributions of funds from jointly owned entities or to transfer our interest in projects or businesses. The control or influence exerted by our joint venture partners may result in operational management and/or investment decisions that are different from the decisions we would make and could impact the profitability and value of these joint ventures. In addition, if a joint venture partner becomes insolvent or bankrupt or is otherwise unable to meet its obligations to or share of liabilities for the joint venture, we may be responsible for meeting certain obligations of the joint ventures to the extent provided for in our governing documents or applicable law. ##TABLE_START 67 | 2022 Annual Report ##TABLE_ENDFurther, we have a significant equity method investment in Fluence. As a publicly listed company, Fluence is governed by its own Board of Directors, whose members have fiduciary duties to the Fluence shareholders. While we have certain rights to appoint representatives to the Fluence Board of Directors, the interests of the Fluence shareholders, as represented by the Fluence Board of Directors, may not align with our interests or the interests of our securityholders. As of December 31, 2022, Fluence continues to report that a material weakness in its internal control over revenue recognition and related inventory has not yet been remediated. Such material weakness can impact the reliability of the Fluence financial information that we may include as part of our financial information. In addition, we are generally dependent on the management team of our equity method investments to operate and control such projects or businesses. While we may exert influence pursuant to having positions on the boards of such investments and/or through certain limited governance rights, such as rights to veto significant actions, we do not always have this type of influence and the scope and impact of such influence may be limited. The management teams of our equity method investments may not have the level of experience, technical expertise, human resources, management and other attributes necessary to operate these projects or businesses optimally, and they may not share our business priorities, which could have a material adverse effect on value of such investments as well as our growth, business, financial condition, results of operations and prospects. Fluctuations in currency exchange rates may impact our financial results and position. Our exposure to currency exchange rate fluctuations results primarily from the translation exposure associated with the preparation of the Consolidated Financial Statements, as well as from transaction exposure associated with transactions in currencies other than an entity's functional currency. While the Consolidated Financial Statements are reported in U.S. dollars, the financial statements of several of our subsidiaries outside the U.S. are prepared using the local currency as the functional currency and translated into U.S. dollars by applying appropriate exchange rates. As a result, fluctuations in the exchange rate of the U.S. dollar relative to the local currencies where our foreign subsidiaries report could cause significant fluctuations in our results. In addition, while our foreign operations expenses are generally denominated in the same currency as corresponding sales, we have transaction exposure to the extent receipts and expenditures are not denominated in the subsidiary's functional currency. Moreover, the costs of doing business abroad may increase as a result of adverse exchange rate fluctuations. We may not be adequately hedged against our exposure to changes in commodity prices or interest rates. We routinely enter into contracts to hedge a portion of our purchase and sale commitments for electricity, fuel requirements and other commodities to lower our financial exposure related to commodity price fluctuations. As part of this strategy, we routinely utilize fixed price or indexed forward physical purchase and sales contracts, futures, financial swaps, and option contracts traded in the over-the-counter markets or on exchanges. We also enter into contracts which help us manage our interest rate exposure. However, we may not cover the entire exposure of our assets or positions to market price or interest rate volatility, and the coverage will vary over time. Furthermore, the risk management practices we have in place may not always perform as planned. In particular, if prices of commodities or interest rates significantly deviate from historical prices or interest rates or if the price or interest rate volatility or distribution of these changes deviates from historical norms, our risk management practices may not protect us from significant losses. As a result, fluctuating commodity prices or interest rates may negatively impact our financial results to the extent we have unhedged or inadequately hedged positions. In addition, certain types of economic hedging activities may not qualify for hedge accounting under U.S. GAAP, resulting in increased volatility in our net income. The Company may also suffer losses associated with "basis risk," which is the difference in performance between the hedge instrument and the underlying exposure (usually the pricing node of the generation facility). Furthermore, there is a risk that the current counterparties to these arrangements may fail or are unable to perform part or all of their obligations under these arrangements, while we seek to protect against that by utilizing strong credit requirements and exchange trades, these protections may not fully cover the exposure in the event of a counterparty default. For our businesses with PPA pricing that does not completely pass through our fuel costs, the businesses attempt to manage the exposure through flexible fuel purchasing and timing of entry and terms of our fuel supply agreements; however, these risk management efforts may not be successful and the resulting commodity exposure could have a material impact on these businesses and/or our results of operations. Our utilities businesses may experience slower growth in customers or in customer usage. Customer growth and customer usage in our utilities businesses are affected by external factors, including mandated energy efficiency measures, demand side management requirements, and economic and demographic ##TABLE_START 68 | 2022 Annual Report ##TABLE_ENDconditions, such as population changes, job and income growth, housing starts, new business formation and the overall level of economic activity. A lack of growth, or a decline, in the number of customers or in customer demand for electricity may cause us to not realize the anticipated benefits from significant investments and expenditures and have a material adverse effect on our business, financial condition, results of operations and prospects. Some of our subsidiaries participate in defined benefit pension plans and their net pension plan obligations may require additional significant contributions. We have 28 defined benefit plans, five at U.S. subsidiaries and the remaining plans at foreign subsidiaries, which cover substantially all of the employees at these subsidiaries. Pension costs are based upon a number of actuarial assumptions, including an expected long-term rate of return on pension plan assets, the expected life span of pension plan beneficiaries and the discount rate used to determine the present value of future pension obligations. Any of these assumptions could prove to be incorrect, resulting in a shortfall of pension plan assets compared to pension obligations under the pension plan. We periodically evaluate the value of the pension plan assets to ensure that they will be sufficient to fund the respective pension obligations. Downturns in the debt and/or equity markets, or the inaccuracy of any of our significant assumptions underlying the estimates of our subsidiaries' pension plan obligations, could result in a material increase in pension expense and future funding requirements. Our subsidiaries that participate in these plans are responsible for satisfying the funding requirements required by law in their respective jurisdictions for any shortfall of pension plan assets as compared to pension obligations under the pension plan, which may necessitate additional cash contributions to the pension plans that could adversely affect our and our subsidiaries' liquidity. See Item 7. Management's Discussion and AnalysisCritical Accounting Policies and EstimatesPension and Other Postretirement Plans and Note 15 Benefit Plans included in Item 8. Financial Statements and Supplementary Data . Impairment of long-lived assets would negatively impact our consolidated results of operations and net worth. Long-lived assets are initially recorded at cost or fair value, are depreciated over their estimated useful lives, and are evaluated for impairment only when impairment indicators are present, such as deterioration in general economic conditions or our operating or regulatory environment; increased competitive environment; lower forecasted revenue; increase in fuel costs, particularly costs that we are unable to pass through to customers; increase in environmental compliance costs; negative or declining cash flows; loss of a key contract or customer, particularly when we are unable to replace it on equally favorable terms; developments in our strategy; divestiture of a significant component of our business; or adverse actions or assessments by a regulator. Any impairment of long-lived assets could have a material adverse effect on our business, financial condition, results of operations, and prospects. Risks associated with Governmental Regulation and Laws Our operations are subject to significant government regulation and could be adversely affected by changes in the law or regulatory schemes. Our ability to predict, influence or respond appropriately to changes in law or regulatory schemes, including obtaining expected or contracted increases in electricity tariff or contract rates or tariff adjustments for increased expenses, could adversely impact our results of operations. Furthermore, changes in laws or regulations or changes in the application or interpretation of regulatory provisions in jurisdictions where we operate, particularly at our utilities where electricity tariffs are subject to regulatory review or approval, could adversely affect our business, including: changes in the determination, definition or classification of costs to be included as reimbursable or pass-through costs to be included in the rates we charge our customers, including but not limited to costs incurred to upgrade our power plants to comply with more stringent environmental regulations; changes in the determination of an appropriate rate of return on invested capital or that a utility's operating income or the rates it charges customers are too high, resulting in a rate reduction or consumer rebates; changes in the definition or determination of controllable or non-controllable costs; changes in tax law; changes in law or regulation that limit or otherwise affect the ability of our counterparties (including sovereign or private parties) to fulfill their obligations (including payment obligations) to us; ##TABLE_START 69 | 2022 Annual Report ##TABLE_END changes in environmental law that impose additional costs or limit the dispatch of our generating facilities; changes in the definition of events that qualify as changes in economic equilibrium; changes in the timing of tariff increases; other changes in the regulatory determinations under the relevant concessions; other changes related to licensing or permitting which affect our ability to conduct business; or other changes that impact the short- or long-term price-setting mechanism in the our markets. Furthermore, in many countries where we conduct business, the regulatory environment is constantly changing and it may be difficult to predict the impact of the regulations on our businesses. The impacts described above could also result from our efforts to comply with European Market Infrastructure Regulation, which includes regulations related to the trading, reporting and clearing of derivatives and similar regulations may be passed in other jurisdictions where we conduct business. Any of the above events may result in lower operating margins and financial results for the affected businesses. Several of our businesses are subject to potentially significant remediation expenses, enforcement initiatives, private party lawsuits and reputational risk associated with CCR. CCR generated at our current and former coal-fired generation plant sites, is currently handled and/or has been handled by: placement in onsite CCR ponds; disposal and beneficial use in onsite and offsite permitted, engineered landfills; use in various beneficial use applications, including encapsulated uses and structural fill; and used in permitted offsite mine reclamation. CCR currently remains onsite at several of our facilities, including in CCR ponds. The EPA's final CCR rule provides that enforcement actions can be commenced by the EPA, states, or territories, and private lawsuits. Compliance with the U.S. federal CCR rule; amendments to the federal CCR rule; or federal, state, territory, or foreign rules or programs addressing CCR may require us to incur substantial costs. In addition, the Company and our businesses may face CCR-related lawsuits in the United States and/or internationally that may expose us to unexpected potential liabilities. Furthermore, CCR-related litigation may also expose us to unexpected costs. In addition, CCR, and its production at several of our facilities, have been the subject of significant interest from environmental non-governmental organizations and have received national and local media attention. The direct and indirect effects of such media attention, and the demands of responding to and addressing it, may divert management time and attention. Any of the foregoing could have a material adverse effect on our business, financial condition, results of operations, reputation and prospects. Some of our U.S. businesses are subject to the provisions of various laws and regulations administered by FERC, NERC and by state utility commissions that can have a material effect on our operations. The AES Corporation is a registered electric holding company under the PUHCA 2005 as enacted as part of the EPAct 2005. PUHCA 2005 eliminated many of the restrictions that had been in place under the U.S. Public Utility Holding Company Act of 1935, while continuing to provide FERC and state utility commissions with enhanced access to the books and records of certain utility holding companies. PUHCA 2005 also creates additional potential challenges and opportunities. By removing some barriers to mergers and other potential combinations, the creation of large, geographically dispersed utility holding companies is more likely. These entities may have enhanced financial strength and therefore an increased ability to compete with us in the U.S. Other parts of the EPAct 2005 allow FERC to remove the PURPA purchase/sale obligations from utilities if there are adequate opportunities to sell into competitive markets. FERC has exercised this power with a rebuttable presumption that utilities located within the control areas of MISO, PJM, ISO New England, Inc., the New York Independent System Operator, Inc., and ERCOT are not required to purchase or sell power from or to QFs above a certain size. Additionally, FERC has the power to remove the purchase/sale obligations of individual utilities on a case-by-case basis. While these changes do not affect existing contracts, certain of our QFs that have had sales contracts expire are now facing a more difficult market environment and that is likely to continue for other AES QFs with existing contracts that will expire over time. FERC strongly encourages competition in wholesale electric markets. Increased competition may have the effect of lowering our operating margins. Among other steps, FERC has encouraged RTOs and ISOs to develop demand response bidding programs as a mechanism for responding to peak electric demand. These programs may reduce the value of generation assets. Similarly, FERC is encouraging the construction of new transmission ##TABLE_START 70 | 2022 Annual Report ##TABLE_ENDinfrastructure in accordance with provisions of EPAct 2005. Although new transmission lines may increase market opportunities, they may also increase the competition in our existing markets. FERC has civil penalty authority over violations of any provision of Part II of the FPA, which concerns wholesale generation or transmission, as well as any rule or order issued thereunder. The FPA also provides for the assessment of criminal fines and imprisonment for violations under the FPA. This penalty authority was enhanced in EPAct 2005. As a result, FERC is authorized to assess a maximum penalty authority established by statute and such penalty authority has been and will continue to be adjusted periodically to account for inflation. With this expanded enforcement authority, violations of the FPA and FERC's regulations could potentially have more serious consequences than in the past. Pursuant to EPAct 2005, the NERC has been certified by FERC as the ERO to develop mandatory and enforceable electric system reliability standards applicable throughout the U.S. to improve the overall reliability of the electric grid. These standards are subject to FERC review and approval. Once approved, the reliability standards may be enforced by FERC independently, or, alternatively, by the ERO and regional reliability organizations with responsibility for auditing, investigating and otherwise ensuring compliance with reliability standards, subject to FERC oversight. Violations of NERC reliability standards are subject to FERC's penalty authority under the FPA and EPAct 2005. Our U.S. utility businesses face significant regulation by their respective state utility commissions. The regulatory discretion is reasonably broad in both Indiana and Ohio and includes regulation as to services and facilities, the valuation of property, the construction, purchase, or lease of electric generating facilities, the classification of accounts, rates of depreciation, the increase or decrease in retail rates and charges, the issuance of certain securities, the acquisition and sale of some public utility properties or securities and certain other matters. These businesses face the risk of unexpected or adverse regulatory action which could have a material adverse effect on our results of operations, financial condition, and cash flows. See Item 1. BusinessUS and Utilities SBU . Our businesses are subject to stringent environmental laws, rules and regulations. Our businesses are subject to stringent environmental laws and regulations by many federal, regional, state and local authorities, international treaties and foreign governmental authorities. These laws and regulations generally concern emissions into the air, effluents into the water, use of water, wetlands preservation, remediation of contamination, waste disposal, endangered species and noise regulation. Failure to comply with such laws and regulations or to obtain or comply with any associated environmental permits could result in fines or other sanctions. For example, in recent years, the EPA has issued NOVs to a number of coal-fired generating plants alleging wide-spread violations of the new source review and prevention of significant deterioration provisions of the CAA. The EPA has brought suit against and obtained settlements with many companies for allegedly making major modifications to a coal-fired generating units without proper permit approvals and without installing best available control technology. The primary focus of these NOVs has been emissions of SO_2 and NO_x and the EPA has imposed fines and required companies to install improved pollution control technologies to reduce such emissions. In addition, state regulatory agencies and non-governmental environmental organizations have pursued civil lawsuits against power plants in situations that have resulted in judgments and/or settlements requiring the installation of expensive pollution controls or the accelerated retirement of certain electric generating units. Furthermore, Congress and other domestic and foreign governmental authorities have either considered or implemented various laws and regulations to restrict or tax certain emissions, particularly those involving air emissions and water discharges. These laws and regulations have imposed, and proposed laws and regulations could impose in the future, additional costs on the operation of our power plants. See Item 1. BusinessEnvironmental and Land-Use Regulations . We have incurred and will continue to incur significant capital and other expenditures to comply with these and other environmental laws and regulations. Changes in, or new development of, environmental restrictions may force us to incur significant expenses or expenses that may exceed our estimates. There can be no assurance that we would be able to recover all or any increased environmental costs from our customers or that our business, financial condition, including recorded asset values or results of operations, would not be materially and adversely affected. ##TABLE_START 71 | 2022 Annual Report ##TABLE_ENDConcerns about GHG emissions and the potential risks associated with climate change have led to increased regulation and other actions that could impact our businesses. International, federal and various regional and state authorities regulate GHG emissions and have created financial incentives to reduce them. In 2022, the Company's subsidiaries operated businesses that had total CO 2 emissions of approximately 40 million metric tonnes, approximately 15 million of which were emitted by our U.S. businesses (both figures are ownership adjusted). The Company uses CO 2 emission estimation methodologies supported by "The Greenhouse Gas Protocol" reporting standard on GHG emissions. For existing power generation plants, CO 2 emissions data are either obtained directly from plant continuous emission monitoring systems or calculated from actual fuel heat inputs and fuel type CO 2 emission factors. This estimate is based on a number of projections and assumptions that may prove to be incorrect, such as the forecasted dispatch, anticipated plant efficiency, fuel type, CO 2 emissions rates and our subsidiaries' achieving completion of such construction and development projects. While actual emissions may vary substantially; the projects under construction or development when completed will increase emissions of our portfolio and therefore could increase the risks associated with regulation of GHG emissions. There currently is no U.S. federal legislation imposing mandatory GHG emission reductions (including for CO 2) that affects our electric power generation facilities; however, in 2015, the EPA promulgated a rule establishing New Source Performance Standards for CO 2 emissions for newly constructed and modified/reconstructed fossil-fueled electric utility steam generating units larger than 25 MW and in 2018 proposed revisions to the rule. In 2019, the EPA promulgated the Affordable Clean Energy (ACE) Rule which establishes heat rate improvement measures as the best system of emissions reductions for existing coal-fired electric generating units. On January 19, 2021, the D.C. Circuit vacated and remanded to the EPA the ACE Rule, but withheld issuance of the mandate that would effectuate its decision. On February 22, 2021, the D.C. Circuit granted EPA's unopposed motion for a partial stay of the issuance of the mandate on vacating the repeal of the CPP. On March 5, 2021, the D.C. Circuit issued the partial mandate effectuating the vacatur of the ACE Rule. In effect, the CPP did not take effect while the EPA is addressing the remand of the ACE rule by promulgating a new Section 111(d) rule to regulate greenhouse gases from existing electric generating units. On October 29, 2021, the U.S. Supreme Court granted petitions to review the decision by the D.C. Circuit to vacate the ACE Rule. On June 30, 2022, Supreme Court reversed the judgment of the D.C. Circuit Court and remanded for further proceedings consistent with its opinion. The opinion held that the generation shifting approach in the CPP exceeded the authority granted to EPA by Congress under Section 111(d) of the CAA. As a result of the June 30, 2022 Supreme Court decision, on October 27, 2022, the D.C. Circuit recalled its March 5, 2021 partial mandate and issued a new partial mandate holding pending challenges to the ACE Rule in abeyance while EPA develops a replacement rule. The impact of the results of further proceedings and potential future greenhouse gas emissions regulations remains uncertain, but it could be material. The impact of the results of such litigation and potential future greenhouse gas emissions regulations remains uncertain, but it could be material. In 2010, the EPA adopted regulations pertaining to GHG emissions that require new and existing sources of GHG emissions to potentially obtain new source review permits from the EPA prior to construction or modification. In 2016, the U.S. Supreme Court ruled that such permitting would only be required if such sources also must obtain a new source review permit for increases in other regulated pollutants. For further discussion of the regulation of GHG emissions, see Item 1. BusinessEnvironmental and Land-Use RegulationsU.S. Environmental and Land-Use Legislation and RegulationsGreenhouse Gas Emissions above. The Parties to the United Nations Framework Convention on Climate Change's Paris Agreement established a long-term goal of keeping the increase in global average temperature well below 2C above pre-industrial levels. We anticipate that the Paris Agreement will continue the trend toward efforts to decarbonize the global economy and to further limit GHG emissions. The impact of GHG regulation on our operations will depend on a number of factors, including the degree and timing of GHG emissions reductions required under any such legislation or regulation, the cost of emissions reduction equipment and the price and availability of offsets, the extent to which market based compliance options are available, the extent to which our subsidiaries would be entitled to receive GHG emissions allowances without having to purchase them in an auction or on the open market and the impact of such legislation or regulation on the ability of our subsidiaries to recover costs incurred through rate increases or otherwise. The costs of compliance could be substantial. Our non-utility, generation subsidiaries seek to pass on any costs arising from CO 2 emissions to contract counterparties. Likewise, our utility subsidiaries seek to pass on any costs arising from CO 2 emissions to customers. However, there can be no assurance that we will effectively pass such costs onto the contract counterparties or ##TABLE_START 72 | 2022 Annual Report ##TABLE_ENDcustomers, respectively, or that the cost and burden associated with any dispute over which party bears such costs would not be burdensome and costly. Furthermore, according to the Intergovernmental Panel on Climate Change, physical risks from climate change could include, but are not limited to, increased runoff and earlier spring peak discharge in many glacier and snow-fed rivers, warming of lakes and rivers, an increase in sea level, and changes and variability in precipitation and in the intensity and frequency of extreme weather events. Physical impacts may have the potential to significantly affect our business and operations. For example, extreme weather events could result in increased downtime and operation and maintenance costs at our electric power transmission and distribution assets and facilities. Variations in weather conditions, primarily temperature and humidity, would also be expected to affect the energy needs of customers. A decrease in energy consumption could decrease our revenues. In addition, while revenues would be expected to increase if the energy consumption of customers increased, such increase could prompt the need for additional investment in generation capacity. In addition to government regulators, many groups, including politicians, environmentalists, the investor community and other private parties have expressed increasing concern about GHG emissions. New regulation, such as the initiatives in Chile, Hawaii, and the Puerto Rico Energy Public Policy Act, may adversely affect our operations. See Item 7. Management's Discussion and AnalysisKey Trends and UncertaintiesDecarbonization Initiatives . Responding to these decarbonization initiatives, including developments in our strategy in line with these initiatives may present challenges to our business. We may be unable to develop our renewables platform as quickly as anticipated. Further, we may be unable to dispose of coal-fired generation assets at anticipated prices, the estimated useful lives of these assets may decrease, and the value of such assets may be impaired. These initiatives could also result in the early retirement of coal-fired generation facilities, which could result in stranded costs if regulators disallow full recovery of investments. Negative public perception of our GHG emissions could have an adverse effect on our relationships with third parties, our ability to attract additional customers, our business development opportunities, and our ability to access finance and insurance for our coal-fired generation assets. In addition, plaintiffs previously brought tort lawsuits that were dismissed against the Company because of its subsidiaries' GHG emissions. Future similar lawsuits may prevail or result in damages awards or other relief. We may also be subject to risks associated with the impact on weather conditions. See Certain of our businesses are sensitive to variations in weather and hydrology and Severe weather and natural disasters may present significant risks to our business and adversely affect our financial results within this section for more information. If any of the foregoing risks materialize, costs may increase or revenues may decrease and there could be a material adverse effect on our results of operations, financial condition,cash flows and reputation. Concerns about data privacy have led to increased regulation and other actions that could impact our businesses. In the ordinary course of business, we collect and retain sensitive information, including personal identifiable information about customers, employees, customer energy usage and other information as well as information regarding business partners and other third parties, some of which may constitute confidential information. The theft, damage or improper disclosure of sensitive electronic data collected by us can subject us to penalties for violation of applicable privacy laws, subject us to claims from third parties, require compliance with notification and monitoring regulations, and harm o ur reputation. Although we maintain technical and organizational measures to protect personal identifiable information and other confidential information, breaches of, or disruptions to, our information technology systems could result in legal claims, liability or penalties under privacy laws or damage to operations or to the company's reputation, which could adversely affect our business. We are also subject to various data privacy and security laws and regulations globally, as well as contractual requirements, as a result of having access to and processing confidential and personal identifiable information in the course of business. If we are unable to comply with applicable laws and regulations or with our contractual commitments, as well as maintain reliable information technology systems and appropriate controls with respect to privacy and security requirements, we may suffer regulatory consequences that could be costly or otherwise adversely affect our business. In addition, any actual or perceived failure on the part of one of our equity affiliates could have a material adverse impact on our results of operations and prospects. ##TABLE_START 73 | 2022 Annual Report ##TABLE_ENDTax legislation initiatives or challenges to our tax positions could adversely affect us. We operate in the U.S. and various non-U.S. jurisdictions and are subject to the tax laws and regulations of the U.S. federal, state and local governments and of many non-U.S. jurisdictions. From time to time, legislative measures may be enacted that could adversely impact our overall tax positions regarding income or other taxes, our effective tax rate or tax payments. For example, in the third quarter of 2022, the Inflation Reduction Act (the IRA) was signed into law in the United States. The IRA includes provisions that are expected to benefit the U.S. clean energy industry, including increases, extensions and/or new tax credits for onshore and offshore wind, solar, storage and hydrogen projects. We expect that the extension of the current solar investment tax credits ("ITCs"), as well as higher credits available for projects that satisfy wage and apprenticeship requirements, will increase demand for our renewables products. In the U.S., the IRA includes a 15% corporate alternative minimum tax based on adjusted financial statement income. We are currently evaluating the applicability and effect of the new law and additional guidance issued in the fourth quarter of 2022. With respect to international tax reform, in the fourth quarter of 2022, the European Commission adopted an amended Directive on Pillar 2 establishing a global minimum tax at a 15% rate. The adoption requires EU Member States to transpose the Directive into their respective national laws by December 31, 2023, for the rules to come into effect as of January 1, 2024. We will continue to monitor issuance of draft legislation in Bulgaria and other relevant EU Member States. The Impact to the Company remains unknown but may be material. Risks Related to our Indebtedness and Financial Condition We have a significant amount of debt. As of December 31, 2022, we had approximately $23 billion of outstanding indebtedness on a consolidated basis. All outstanding borrowings under The AES Corporation's revolving credit facility are unsecured. Most of the debt of The AES Corporation's subsidiaries, however, is secured by substantially all of the assets of those subsidiaries. A substantial portion of cash flow from operations must be used to make payments on our debt. Furthermore, since a significant percentage of our assets are used to secure this debt, this reduces the amount of collateral available for future secured debt or credit support and reduces our flexibility in operating these secured assets. This level of indebtedness and related security could have other consequences, including: making it more difficult to satisfy debt service and other obligations; increasing our vulnerability to general adverse industry and economic conditions, including adverse changes in foreign exchange rates, interest rates and commodity prices; reducing available cash flow to fund other corporate purposes and grow our business; limiting our flexibility in planning for, or reacting to, changes in our business and the industry; placing us at a competitive disadvantage to our competitors that are not as highly leveraged; and limiting, along with financial and other restrictive covenants relating to such indebtedness, our ability to borrow additional funds, pay cash dividends or repurchase common stock. The agreements governing our indebtedness, including the indebtedness of our subsidiaries, limit, but do not prohibit the incurrence of additional indebtedness. If we were to become more leveraged, the risks described above would increase. Further, our actual cash requirements may be greater than expected and our cash flows may not be sufficient to repay all of the outstanding debt as it becomes due. In that event, we may not be able to borrow money, sell assets, raise equity or otherwise raise funds on acceptable terms to refinance our debt as it becomes due. In addition, our ability to refinance existing or future indebtedness will depend on the capital markets and our financial condition at that time. Any refinancing of our debt could result in higher interest rates or more onerous covenants that restrict our business operations. See Note 11 Debt included in Item 8. Financial Statements and Supplementary Data for a schedule of our debt maturities. The AES Corporation's ability to make payments on its outstanding indebtedness is dependent upon the receipt of funds from our subsidiaries. The AES Corporation is a holding company with no material assets other than the stock of its subsidiaries. Almost all of The AES Corporation's cash flow is generated by the operating activities of its subsidiaries. Therefore, The AES Corporation's ability to make payments on its indebtedness and to fund its other obligations is dependent not only on the ability of its subsidiaries to generate cash, but also on the ability of the subsidiaries to distribute cash to it in the form of dividends, fees, interest, tax sharing payments, loans or otherwise.Our subsidiaries face various ##TABLE_START 74 | 2022 Annual Report ##TABLE_ENDrestrictions in their ability to distribute cash. Most of the subsidiaries are obligated, pursuant to loan agreements, indentures or non-recourse financing arrangements, to satisfy certain restricted payment covenants or other conditions before they may make distributions. Business performance and local accounting and tax rules may also limit dividend distributions. Subsidiaries in foreign countries may also be prevented from distributing funds as a result of foreign governments restricting the repatriation of funds or the conversion of currencies. Our subsidiaries are separate and distinct legal entities and, unless they have expressly guaranteed The AES Corporation's indebtedness, have no obligation, contingent or otherwise, to pay any amounts due pursuant to such debt or to make any funds available whether by dividends, fees, loans or other payments. Existing and potential future defaults by subsidiaries or affiliates could adversely affect us. We attempt to finance our domestic and foreign projects through non-recourse debt or "non-recourse financing" that requires the loans to be repaid solely from the project's revenues and provide that the repayment of the loans (and interest thereon) is secured solely by the capital stock, physical assets, contracts and cash flow of that project subsidiary or affiliate. As of December 31, 2022, we had approximately $23 billion of outstanding indebtedness on a consolidated basis, of which approximately $3.9 billion was recourse debt of the Parent Company and approximately $19.4 billion was non-recourse debt. In some non-recourse financings, the Parent Company has explicitly agreed, in the form of guarantees, indemnities, letters of credit, letter of credit reimbursement agreements and agreements to pay, to undertake certain limited obligations and contingent liabilities, most of which will only be effective or will be terminated upon the occurrence of future events. Certain of our subsidiaries are in default with respect to all or a portion of their outstanding indebtedness. The total debt classified as current in our Consolidated Balance Sheets related to such defaults was $177 million as of December 31, 2022. While the lenders under our non-recourse financings generally do not have direct recourse to the Parent Company, such defaults under non-recourse financings can: reduce the Parent Company's receipt of subsidiary dividends, fees, interest payments, loans and other sources of cash because a subsidiary will typically be prohibited from distributing cash to the Parent Company during the pendency of any default; trigger The AES Corporation's obligation to make payments under any financial guarantee, letter of credit or other credit support provided to or on behalf of such subsidiary; trigger defaults in the Parent Company's outstanding debt. For example, The AES Corporation's revolving credit facility and outstanding senior notes include events of default for certain bankruptcy related events involving material subsidiaries and relating to accelerations of outstanding material debt of material subsidiaries or any subsidiaries that in the aggregate constitute a material subsidiary; or result in foreclosure on the assets that are pledged under the non-recourse financings, resulting in write-downs of assets and eliminating any and all potential future benefits derived from those assets. None of the projects that are in default are owned by subsidiaries that, individually or in the aggregate, meet the applicable standard of materiality in The AES Corporation's revolving credit facility or other debt agreements to trigger an event of default or permit acceleration under such indebtedness. However, as a result of future mix of distributions, write-down of assets, dispositions and other changes to our financial position and results of operations, one or more of these subsidiaries, individually or in the aggregate, could fall within the applicable standard of materiality and thereby upon an acceleration of such subsidiary's debt, trigger an event of default and possible acceleration of Parent Company indebtedness. The AES Corporation has significant cash requirements and limited sources of liquidity. The AES Corporation requires cash primarily to fund: principal repayments of debt, interest, dividends on our common stock, acquisitions, construction and other project commitments, other equity commitments (including business development investments); equity repurchases; taxes and Parent Company overhead costs. Our principal sources of liquidity are: dividends and other distributions from our subsidiaries, proceeds from financings at the Parent Company, and proceeds from asset sales. See Item 7. Management's Discussion and Analysis Capital Resources and Liquidity . We believe that these sources will be adequate to meet our obligations for the foreseeable future, based on a number of material assumptions about access the capital or commercial lending markets, the operating and financial performance of our subsidiaries, exchange rates, our ability to sell assets, and the ability of our subsidiaries to pay dividends and other distributions; however, there can be no assurance that these sources will be available when needed or that our actual cash requirements will not be greater than expected. In addition, our cash flow may not be sufficient to repay our debt obligations at maturity and we may have to refinance such ##TABLE_START 75 | 2022 Annual Report ##TABLE_ENDobligations. There can be no assurance that we will be successful in obtaining such refinancing on acceptable terms. Our ability to grow our business depends on our ability to raise capital on favorable terms. We rely on the capital markets as a source of liquidity for capital requirements not satisfied by operating cash flows. Our ability to arrange for financing on either a recourse or non-recourse basis and the costs of such capital are dependent on numerous factors, some of which are beyond our control, including: general economic and capital market conditions; the availability of bank credit; the availability of tax equity partners; the financial condition, performance and prospects of AES as well as our competitors; and changes in tax and securities laws. Should access to capital not be available to us, we may have to sell assets or cease further investments, including the expansion or improvement of existing facilities, any of which would affect our future growth. A downgrade in the credit ratings of The AES Corporation or its subsidiaries could adversely affect our access to the capital markets, interest expense, liquidity or cash flow. If any of the credit ratings of the The AES Corporation and its subsidiaries were to be downgraded, our ability to raise capital on favorable terms could be impaired and our borrowing costs could increase. Furthermore, counterparties may no longer be willing to accept general unsecured commitments by The AES Corporation to provide credit support. Accordingly, we may be required to provide some other form of assurance, such as a letter of credit and/or collateral, to backstop or replace any credit support by The AES Corporation, which reduces our available credit. There can be no assurance that counterparties will accept such guarantees or other assurances. The market price of our common stock may be volatile. The market price and trading volumes of our common stock could fluctuate substantially due to factors including general economic conditions, conditions in our industry and our markets, environmental and economic developments, and general credit and capital markets conditions, as well as developments specific to us, including risks described in this section, failing to meet our publicly announced guidance or key trends and other matters described in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations .

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Item 1. BUSINESS Southern Company is a holding company that owns all of the outstanding common stock of three traditional electric operating companies, Southern Power Company, and Southern Company Gas. The traditional electric operating companies Alabama Power, Georgia Power, and Mississippi Power are each operating public utility companies providing electric service to retail customers in three Southeastern states in addition to wholesale customers in the Southeast. Southern Power Company is also an operating public utility company. The term "Southern Power" when used herein refers to Southern Power Company and its subsidiaries, while the term "Southern Power Company" when used herein refers only to the Southern Power parent company. Southern Power develops, constructs, acquires, owns, and manages power generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Company Gas is an energy services holding company whose primary business is the distribution of natural gas in four states Illinois, Georgia, Virginia, and Tennessee through the natural gas distribution utilities. Southern Company Gas is also involved in several other businesses that are complementary to the distribution of natural gas. Southern Company also owns SCS, Southern Linc, Southern Holdings, Southern Nuclear, PowerSecure, and other direct and indirect subsidiaries. SCS, the system service company, has contracted with Southern Company, each of the Subsidiary Registrants, Southern Nuclear, SEGCO, and other subsidiaries to furnish, at direct or allocated cost and upon request, the following services: general executive and advisory, general and design engineering, operations, purchasing, accounting, finance, treasury, legal, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, cellular tower space, and other services with respect to business and operations, construction management, and Southern Company power pool transactions. Southern Linc provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber optics services through its subsidiary, Southern Telecom, Inc. Southern Linc's system covers approximately 122,000 square miles in the Southeast. Southern Holdings is an intermediate holding company subsidiary, which invests in various projects. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants and is currently managing construction of and developing Plant Vogtle Units 3 and 4, which are co-owned by Georgia Power. PowerSecure develops distributed energy and resilience solutions and deploys microgrids for commercial, industrial, governmental, and utility customers. See "The Southern Company System" herein for additional information. Also see Note 15 to the financial statements in Item 8 herein for information regarding recent acquisition and disposition activity. Segment information for Southern Company and Southern Company Gas is included in Note 16 to the financial statements in Item 8 herein. Alabama Power, Georgia Power, and Mississippi Power each operate with one reportable business segment, since substantially all of their business is providing electric service to customers. Southern Power also operates its business with one reportable business segment, the sale of electricity in the competitive wholesale market. The Registrants' Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and any amendments to those reports are made available on Southern Company's website, free of charge, as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC. Southern Company's internet address is www.southerncompany.com. The Southern Company System Traditional Electric Operating Companies The traditional electric operating companies are vertically integrated utilities that own generation, transmission, and distribution facilities. See PROPERTIES in Item 2 herein for additional information on the traditional electric operating companies' generating facilities. Each company's transmission facilities are connected to the respective company's own generating plants and other sources of power (including certain generating plants owned by Southern Power) and are interconnected with the transmission facilities of the other traditional electric operating companies and SEGCO. For information on the State of Georgia's integrated transmission system, see "Territory Served by the Southern Company System Traditional Electric Operating Companies and Southern Power" herein. Agreements in effect with principal neighboring utility systems provide for capacity and energy transactions that may be entered into for reasons related to reliability or economics. Additionally, the traditional electric operating companies have entered into various reliability agreements with certain neighboring utilities, each of which provides for the establishment and periodic review of principles and procedures for planning and operation of generation and transmission facilities, maintenance I-1 Index to Financial Statements schedules, load retention programs, emergency operations, and other matters affecting the reliability of bulk power supply. The traditional electric operating companies have joined with other utilities in the Southeast to form the SERC to augment further the reliability and adequacy of bulk power supply. Through the SERC, the traditional electric operating companies are represented at the North American Electric Reliability Corporation. On November 9, 2022, the Southeast Energy Exchange Market (SEEM) began service. SEEM, whose members include the traditional electric operating companies and many of the other electric service providers in the Southeast, is an extension of the existing bilateral market where participants use an automated, intra-hour energy exchange to buy and sell power close to the time the energy is consumed, utilizing available unreserved transmission. The FERC's orders related to SEEM have been appealed. The ultimate outcome of this matter cannot be determined at this time. The utility assets of the traditional electric operating companies and certain utility assets of Southern Power Company are operated as a single integrated electric system, or Southern Company power pool, pursuant to the IIC. Activities under the IIC are administered by SCS, which acts as agent for the traditional electric operating companies and Southern Power Company. The fundamental purpose of the Southern Company power pool is to provide for the coordinated operation of the electric facilities in an effort to achieve the maximum possible economies consistent with the highest practicable reliability of service. Subject to service requirements and other operating limitations, system resources are committed and controlled through the application of centralized economic dispatch. Under the IIC, each traditional electric operating company and Southern Power Company retains its lowest cost energy resources for the benefit of its own customers and delivers any excess energy to the Southern Company power pool for use in serving customers of other traditional electric operating companies or Southern Power Company or for sale by the Southern Company power pool to third parties. The IIC provides for the recovery of specified costs associated with the affiliated operations thereunder, as well as the proportionate sharing of costs and revenues resulting from Southern Company power pool transactions with third parties. Southern Power and Southern Linc have secured from the traditional electric operating companies certain services which are furnished in compliance with FERC regulations. Alabama Power and Georgia Power each have agreements with Southern Nuclear to operate the Southern Company system's existing nuclear plants, Plants Farley, Hatch, and Vogtle. In addition, Georgia Power has an agreement with Southern Nuclear to develop, license, construct, and operate Plant Vogtle Units 3 and 4. See "Regulation Nuclear Regulation" herein for additional information. Southern Power Southern Power develops, constructs, acquires, owns, and manages power generation assets, including renewable energy projects, and sells electricity at market-based rates (under authority from the FERC) in the wholesale market. Southern Power seeks opportunities to execute its strategy to create value through various transactions including acquisitions, dispositions, and sales of partnership interests, development and construction of new generating facilities, and entry into PPAs, including contracts for differences that provide the owner of a renewable facility a certain fixed price for electricity sold to the grid, primarily with investor-owned utilities, IPPs, municipalities, electric cooperatives, and other load-serving entities, as well as commercial and industrial customers. The electricity from the natural gas generating facilities owned by Southern Power is primarily sold under long-term, fixed-price capacity PPAs both with unaffiliated wholesale purchasers as well as with the traditional electric operating companies. Southern Power has attempted to insulate itself from significant fuel supply, fuel transportation, and electric transmission risks by generally making such risks the responsibility of the counterparties to its PPAs. However, Southern Power's future earnings will depend on the parameters of the wholesale market and the efficient operation of its wholesale generating assets, as well as Southern Power's ability to execute its growth strategy and to develop and construct generating facilities. Southern Power's business activities are not subject to traditional state regulation like the traditional electric operating companies, but the majority of its business activities are subject to regulation by the FERC. For additional information on Southern Power's business activities, see MANAGEMENT'S DISCUSSION AND ANALYSIS OVERVIEW "Business Activities" in Item 7 herein. Southern Power Company directly owns and manages generation assets primarily in the Southeast, which are included in the Southern Company power pool, and has various subsidiaries whose generation assets are not included in the Southern Company power pool. These subsidiaries were created to own, operate, and pursue power generation facilities, either wholly or in partnership with various third parties. At December 31, 2022, Southern Power's generation fleet, which is owned in part with various partners, totaled 12,501 MWs of nameplate capacity in commercial operation (including 5,121 MWs of nameplate capacity owned by its subsidiaries). See "Traditional Electric Operating Companies" herein for additional information on the Southern Company power pool. A majority of Southern Power's partnerships in renewable facilities allow for the sharing of cash distributions and tax benefits at differing percentages, with Southern Power being the controlling partner and thus consolidating the assets and operations of the partnerships. At December 31, 2022, Southern Power had eight tax equity partnership arrangements where the tax equity I-2 Index to Financial Statements investors receive substantially all of the tax benefits from the facilities, including ITCs and PTCs. In addition, Southern Power holds controlling interests in non-tax equity partnerships with its ownership interests primarily ranging from 51% to 66%. See PROPERTIES in Item 2 herein for additional detail regarding Southern Power's partnership arrangements and Note 15 to the financial statements under "Southern Power" in Item 8 herein for additional information regarding Southern Power's acquisitions, dispositions, construction, and development projects.

Southern Power calculates an investment coverage ratio for its generating assets, including those owned with various partners, based on the ratio of investment under contract to total investment using the respective facilities' net book value (or expected in-service value for facilities under construction) as the investment amount. With the inclusion of investments associated with facilities under construction, as well as other capacity and energy contracts, Southern Power's average investment coverage ratio at December 31, 2022 was 96% through 2027 and 90% through 2032, with an average remaining contract duration of approximately 12 years. For the year ended December 31, 2022, approximately 44% of contracted MWs were with AAA to A- or equivalent rated counterparties, 43% were with BBB+ to BBB- or equivalent rated counterparties, and 11% were with unrated entities that either have ratemaking authority or have posted collateral to cover potential credit exposure. Southern Power's electricity sales from natural gas generating facilities are primarily through long-term PPAs that consist of two types of agreements. The first type, referred to as a unit or block sale, is a customer purchase from a dedicated plant unit where all or a portion of the generation from that unit is reserved for that customer. Southern Power typically has the ability to serve the unit or block sale customer from an alternate resource. The second type, referred to as requirements service, provides that Southern Power serves the customer's capacity and energy requirements from a combination of the customer's own generating units and from Southern Power resources not dedicated to serve unit or block sales. Southern Power has rights to purchase power provided by the requirements customers' resources when economically viable. Capacity charges that form part of the PPA payments are designed to recover fixed and variable operations and maintenance costs based on dollars-per-kilowatt year and to provide a return on investment. Southern Power's electricity sales from solar and wind generating facilities are also primarily through long-term PPAs; however, these solar and wind PPAs do not have a capacity charge and customers either purchase the energy output of a dedicated renewable facility through an energy charge or provide Southern Power a certain fixed price for the electricity sold to the grid. As a result, Southern Power's ability to recover fixed and variable operations and maintenance expenses is dependent upon the level of energy generated from these facilities, which can be impacted by weather conditions, equipment performance, transmission constraints, and other factors. Generally, under the renewable generation PPAs, the purchasing party retains the right to keep or resell the renewable energy credits. Southern Power actively pursues replacement PPAs prior to the expiration of its current PPAs and anticipates that the revenues attributable to one customer may be replaced by revenues from a new customer; however, the expiration of any of Southern Power's current PPAs without the successful remarketing of a replacement PPA could have a material negative impact on Southern Power's earnings but is not expected to have a material impact on Southern Company's earnings. Southern Company Gas Southern Company Gas is an energy services holding company whose primary business is the distribution of natural gas through the natural gas distribution utilities. Southern Company Gas is also involved in several other businesses that are complementary to the distribution of natural gas, including gas pipeline investments and gas marketing services. Southern Company Gas also has an "all other" non-reportable segment that includes segments below the quantitative threshold for separate disclosure, including storage operations and subsidiaries that fall below the quantitative threshold for separate disclosure. Prior to the sale of Sequent on July 1, 2021, Southern Company Gas' other businesses also included wholesale gas services. See Note 15 to the financial statements under "Southern Company Gas" in Item 8 herein for information regarding Southern Company Gas' recent dispositions, including the sale of Sequent and the sale and pending sale of the remaining facilities within the storage operations business. Gas distribution operations, the largest segment of Southern Company Gas' business, operates, constructs, and maintains 77,591 miles of natural gas pipelines and 14 storage facilities, with total capacity of 157 Bcf, to provide natural gas to residential, commercial, and industrial customers. Gas distribution operations serves approximately 4.4 million customers across four states. Gas pipeline investments primarily consists of joint ventures in natural gas pipeline investments including a 50% interest in SNG and a 50% joint ownership interest in the Dalton Pipeline. These natural gas pipelines enable the provision of diverse sources of natural gas supplies to the customers of Southern Company Gas. SNG, the largest natural gas pipeline investment, is the owner of a 7,000-mile pipeline connecting natural gas supply basins in Texas, Louisiana, Mississippi, and Alabama to markets in Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina, and Tennessee. Gas pipeline investments also includes a 20% ownership interest in the PennEast Pipeline project, which was cancelled in September 2021. For additional I-3 Index to Financial Statements information on Southern Company Gas's pipeline investments, see Note 7 to the financial statements under "Southern Company Gas" in Item 8 herein. Gas marketing services is comprised of SouthStar, which serves approximately 622,000 natural gas commodity customers, markets gas to residential, commercial, and industrial customers and offers energy-related products that provide natural gas price stability and utility bill management in competitive markets or markets that provide for customer choice. Construction Programs The subsidiary companies of Southern Company are engaged in continuous construction programs, including capital expenditures to accommodate existing and estimated future loads on their respective systems and to comply with environmental laws and regulations, as applicable. In 2023, the Southern Company system's construction program is expected to be apportioned approximately as follows: ##TABLE_START Southern Company system (a)(b) Alabama Power Georgia Power (a) Mississippi Power (a) (in billions) New generation $ 1.2 $ 0.1 $ 1.1 $ Environmental compliance (c) 0.1 0.1 0.1 Generation maintenance 1.2 0.5 0.6 0.1 Transmission 1.5 0.4 1.1 0.1 Distribution 1.6 0.4 1.1 0.1 Nuclear fuel 0.3 0.1 0.2 General plant 1.0 0.4 0.5 0.1 6.9 2.0 4.6 0.3 Southern Power (d) 0.1 Southern Company Gas (e) 1.8 Other subsidiaries 0.2 Total (a) $ 9.1 $ 2.0 $ 4.6 $ 0.3 ##TABLE_END(a) Totals may not add due to rounding. (b) Includes the Subsidiary Registrants, as well as other subsidiaries. (c) Reflects cost estimates for environmental laws and regulations.

These estimated expenditures do not include any potential compliance costs associated with any future regulation of CO_2 emissions from fossil fuel-fired electric generating units or costs associated with closure and monitoring of ash ponds and landfills in accordance with the CCR Rule and the related state rules. See MANAGEMENT'S DISCUSSION AND ANALYSIS FUTURE EARNINGS POTENTIAL "Environmental Matters" and FINANCIAL CONDITION AND LIQUIDITY "Cash Requirements" in Item 7 herein for additional information. No material capital expenditures are expected for non-environmental government regulations. (d) Does not include approximately $0.5 billion for planned acquisitions and placeholder growth, which may vary materially due to market opportunities and Southern Power's ability to execute its growth strategy. (e) Includes costs for ongoing capital projects associated with infrastructure improvement programs for certain natural gas distribution utilities that have been previously approved by their applicable state regulatory agencies. See Note 2 to the financial statements under "Southern Company Gas" in Item 8 herein for additional information. The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. The traditional electric operating companies also anticipate continued expenditures associated with closure and monitoring of ash ponds and landfills in accordance with the CCR Rule and the related state rules, which are reflected in the applicable Registrants' ARO liabilities. Estimated costs for 2023 total $672 million for Southern Company, primarily consisting of $330 million for Alabama Power, $295 million for Georgia Power, and $21 million for Mississippi Power. See MANAGEMENT'S DISCUSSION AND ANALYSIS FINANCIAL CONDITION AND LIQUIDITY "Cash Requirements" in Item 7 herein for additional information, including estimated expenditures for construction, environmental compliance, and closure and monitoring of ash ponds and landfills for the years 2024 through 2027. Also see MANAGEMENT'S DISCUSSION AND ANALYSIS FUTURE EARNINGS POTENTIAL "Environmental Matters" in Item 7 herein for additional information with respect to certain existing and proposed environmental requirements and PROPERTIES "Electric Jointly-Owned Facilities" and "Natural Gas Jointly-Owned Properties" in Item 2 herein and Note 5 to the financial statements under "Joint Ownership Agreements" in Item 8 herein for additional information concerning the Registrants' joint ownership of certain facilities. I-4 Index to Financial Statements Financing Programs See MANAGEMENT'S DISCUSSION AND ANALYSIS FINANCIAL CONDITION AND LIQUIDITY in Item 7 herein and Note 8 to the financial statements in Item 8 herein for information concerning financing programs. Fuel Supply Electric The traditional electric operating companies' and SEGCO's supply of electricity is primarily fueled by natural gas and coal, as well as nuclear for Alabama Power and Georgia Power. Southern Power's supply of electricity is primarily fueled by natural gas. See MANAGEMENT'S DISCUSSION AND ANALYSIS RESULTS OF OPERATION "Southern Company Electricity Business Fuel and Purchased Power Expenses" and MANAGEMENT'S DISCUSSION AND ANALYSIS RESULTS OF OPERATION under "Fuel and Purchased Power Expenses" for each of the traditional electric operating companies in Item 7 herein for information regarding the electricity generated and the average cost of fuel in cents per net KWH generated for the years 2021 and 2022. SCS, acting on behalf of the traditional electric operating companies and Southern Power Company, has agreements in place for the natural gas burn requirements of the Southern Company system. For 2023, SCS has contracted for 659 Bcf of natural gas supply under agreements with remaining terms up to 11 years. In addition to natural gas supply, SCS has contracts in place for both firm natural gas transportation and storage. Management believes these contracts provide sufficient natural gas supplies, transportation, and storage to ensure normal operations of the Southern Company system's natural gas generating units. The traditional electric operating companies have agreements in place from which they expect to receive substantially all of their 2023 coal burn requirements. These agreements have terms ranging between one and three years. Fuel procurement specifications, emission allowances, environmental control systems, and fuel changes have allowed the traditional electric operating companies to remain within limits set by applicable environmental regulations. As new environmental regulations are proposed that impact the utilization of coal, the traditional electric operating companies' fuel mix will be monitored to help ensure compliance with applicable laws and regulations. Southern Company and the traditional electric operating companies will continue to evaluate the need to purchase additional emissions allowances, the timing of capital expenditures for environmental control equipment, and potential unit retirements and replacements. While none of Southern Company's subsidiaries are currently subject to renewable portfolio standards or similar requirements, management of the traditional electric operating companies is working with applicable regulators through their IRP processes to continue the generating fleet transition in a manner responsible to customers, communities, employees, and other stakeholders. See MANAGEMENT'S DISCUSSION AND ANALYSIS FUTURE EARNINGS POTENTIAL "Environmental Matters" in Item 7 herein and Note 2 to the financial statements under "Alabama Power Environmental Accounting Order," "Georgia Power Integrated Resource Plans," and "Mississippi Power Integrated Resource Plan" in Item 8 herein for additional information, including the Southern Company system's electric generating mix and plans to retire or convert to natural gas certain coal-fired generating capacity. Alabama Power and Georgia Power have multiple contracts covering their nuclear fuel needs for uranium, conversion services, enrichment services, and fuel fabrication with remaining terms ranging from one to 12 years. Management believes suppliers have sufficient nuclear fuel production capability to permit normal operation of the Southern Company system's nuclear generating units. Alabama Power and Georgia Power also have contracts with the United States, acting through the DOE, that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent fuel in 1998, as required by the contracts, and Alabama Power and Georgia Power have pursued and are pursuing legal remedies against the government for breach of contract. See Note 3 to the financial statements under "Nuclear Fuel Disposal Costs" in Item 8 herein for additional information. Changes in fuel prices to the traditional electric operating companies are generally reflected in fuel adjustment clauses contained in rate schedules. See "Rate Matters Rate Structure and Cost Recovery Plans" herein for additional information. Southern Power's natural gas PPAs generally provide that the counterparty is responsible for substantially all of the cost of fuel. Natural Gas Advances in natural gas drilling in shale producing regions of the United States have resulted in historically high supplies of natural gas. Demand increases beginning in 2021 and continuing in 2022 resulted in price increases and high volatility, which has been exacerbated by pipeline constraints and increased exports. The Henry Hub price averaged $6.38 per mmBtu in 2022. Current forecasts for 2023 are approximately $3.30. Forward market prices for 2024 and beyond indicate expectations, absent unforeseen developments, that prices will modestly increase. The potential for price increases, similar to those in 2022, and high volatility remains. Procurement plans for natural gas supply and transportation to serve regulated utility customers are reviewed and approved by the regulatory agencies in the states where Southern Company Gas operates. Southern Company Gas I-5 Index to Financial Statements purchases natural gas supplies in the open market by contracting with producers and marketers and, for Atlanta Gas Light and Chattanooga Gas, under asset management agreements approved by the applicable state regulatory agency. Southern Company Gas also contracts for transportation and storage services from interstate pipelines that are regulated by the FERC. When firm pipeline services are temporarily not needed, Southern Company Gas may release the services in the secondary market under FERC-approved capacity release provisions or utilize asset management arrangements, thereby reducing the net cost of natural gas charged to customers for most of the natural gas distribution utilities. Peak-use requirements are met through utilization of company-owned storage facilities, pipeline transportation capacity, purchased storage services, peaking facilities, and other supply sources, arranged by either transportation customers or Southern Company Gas. See Note 15 to the financial statements under "Southern Company Gas" in Item 8 herein for additional information on the sale of Sequent. Territory Served by the Southern Company System Traditional Electric Operating Companies and Southern Power The territory in which the traditional electric operating companies provide retail electric service comprises most of the states of Alabama and Georgia, together with southeastern Mississippi. In this territory there are non-affiliated electric distribution systems that obtain some or all of their power requirements either directly or indirectly from the traditional electric operating companies. As of December 31, 2022, the territory had an area of approximately 116,000 square miles and an estimated population of approximately 17 million. Southern Power sells wholesale electricity at market-based rates across various U.S. utility markets, primarily to investor-owned utilities, IPPs, municipalities, and other load-serving entities, as well as commercial and industrial customers. Alabama Power is engaged, within the State of Alabama, in the generation, transmission, distribution, and purchase of electricity and the sale of electric service, at retail in approximately 400 cities and towns (including Anniston, Birmingham, Gadsden, Mobile, Montgomery, and

Tuscaloosa), as well as in rural areas, and at wholesale to 11 municipally-owned electric distribution systems, all of which are served indirectly through sales to AMEA, and two rural distributing cooperative associations. The sales contract with AMEA will expire on December 31, 2025. In addition, Alabama Power sells, and cooperates with dealers in promoting the sale of, electric appliances and products and also markets and sells outdoor lighting services. Georgia Power is engaged in the generation, transmission, distribution, and purchase of electricity and the sale of electric service within the State of Georgia, at retail in over 530 cities and towns (including Athens, Atlanta, Augusta, Columbus, Macon, Rome, and Savannah), as well as in rural areas, and at wholesale to OPC, MEAG Power, Dalton, various EMCs, and non-affiliated utilities. Georgia Power also markets and sells outdoor lighting services and other customer-focused utility services. Mississippi Power is engaged in the generation, transmission, distribution, and purchase of electricity and the sale of electric service within 23 counties in southeastern Mississippi, at retail in 123 communities (including Biloxi, Gulfport, Hattiesburg, Laurel, Meridian, and Pascagoula), as well as in rural areas, and at wholesale to one municipality, six rural electric distribution cooperative associations, and one generating and transmitting cooperative. The following table provides the number of retail customers served by customer classification for the traditional electric operating companies at December 31, 2022: ##TABLE_START Alabama Power Georgia Power Mississippi Power Total (*) (in thousands) Residential 1,320 2,367 157 3,844 Commercial 206 326 34 566 Industrial 6 11 17 Other 1 9 10 Total (*) 1,533 2,713 192 4,437 ##TABLE_END(*) Totals may not add due to rounding. For information relating to KWH sales by customer classification for the traditional electric operating companies, see MANAGEMENT'S DISCUSSION AND ANALYSIS RESULTS OF OPERATIONS in Item 7 herein. Also, for information relating to the sources of revenues for Southern Company, each traditional electric operating company, and Southern Power, see Item 7 herein and Note 1 to the financial statements under "Revenues Traditional Electric Operating Companies" and " Southern Power" and Note 4 to the financial statements in Item 8 herein. I-6 Index to Financial Statements As of December 31, 2022, there were 62 electric cooperative distribution systems operating in the territories in which the traditional electric operating companies provide electric service at retail or wholesale. PowerSouth is a generating and transmitting cooperative selling power to several distributing cooperatives, municipal systems, and other customers in south Alabama. As of December 31, 2022, PowerSouth owned generating units with more than 1,600 MWs of nameplate capacity, including an undivided 8.16% ownership interest in Alabama Power's Plant Miller Units 1 and 2. See PROPERTIES "Electric Jointly-Owned Facilities" in Item 2 herein and Note 5 to the financial statements under "Joint Ownership Agreements" in Item 8 herein for additional information. Alabama Power has power supply agreements with PowerSouth to provide 100 MWs of year-round capacity service from November 1, 2020 through February 28, 2023, 200 MWs of year-round capacity service through January 31, 2024, and 200 MWs of winter-only capacity service through December 31, 2023. Additionally, in accordance with an agreement executed in August 2021, Alabama Power will provide approximately 100 MWs of year-round capacity service to PowerSouth beginning February 1, 2024. In September 2021, Alabama Power and PowerSouth began operations under a coordinated planning and operations agreement, with a minimum term of 10 years. The agreement includes combined operations (including joint commitment and dispatch) and real-time energy sales and purchases and is expected to create energy cost savings and enhanced system reliability for both parties. Projected revenues are expected to offset any increased administrative costs incurred by Alabama Power. Under the agreement, Alabama Power has the right to participate in a portion of PowerSouth's future incremental load growth. Alabama Power also has a separate agreement with PowerSouth involving interconnection between their systems. The delivery of capacity and energy from PowerSouth to certain distributing cooperatives in the service territory of Alabama Power is governed by the Southern Company/PowerSouth Network Transmission Service Agreement. The rates for this service to PowerSouth are on file with the FERC. OPC is an EMC owned by its 38 retail electric distribution cooperatives, which provide retail electric service to customers in Georgia. OPC provides wholesale electric power to its members through its generation assets, some of which are jointly owned with Georgia Power, and power purchased from other suppliers. OPC and the 38 retail electric distribution cooperatives are members of Georgia Transmission Corporation, an EMC (GTC), which provides transmission services to its members and third parties. See PROPERTIES "Electric Jointly-Owned Facilities" in Item 2 herein and Note 5 to the financial statements under "Joint Ownership Agreements" in Item 8 herein for additional information regarding Georgia Power's jointly-owned facilities. Mississippi Power has an interchange agreement with Cooperative Energy, a generating and transmitting cooperative, pursuant to which various services are provided. Cooperative Energy also has a 10-year network integration transmission service agreement with SCS for transmission service to certain delivery points on Mississippi Power's transmission system through March 31, 2031. See Note 2 to the financial statements under "Mississippi Power Municipal and Rural Associations Tariff" in Item 8 herein for information on a separate shared service agreement between Mississippi Power and Cooperative Energy. As of December 31, 2022, there were 72 municipally-owned electric distribution systems operating in the territory in which the traditional electric operating companies provide electric service at retail or wholesale. As of December 31, 2022, 48 municipally-owned electric distribution systems and one county-owned system received their requirements through MEAG Power. MEAG Power serves these requirements from self-owned generation facilities, some of which are jointly-owned with Georgia Power, and purchases from other resources. MEAG Power also has a pseudo scheduling and services agreement with Georgia Power. Dalton serves its requirements from self-owned generation facilities, some of which are jointly-owned with Georgia Power, and through purchases from Southern Power through a service agreement. See PROPERTIES "Electric Jointly-Owned Facilities" in Item 2 herein and Note 5 to the financial statements under "Joint Ownership Agreements" in Item 8 herein for additional information. Georgia Power has entered into substantially similar agreements with GTC, MEAG Power, and Dalton providing for the establishment of an integrated transmission system to carry the power and energy of all parties. The agreements require an investment by each party in the integrated transmission system in proportion to its respective share of the aggregate system load. See PROPERTIES "Electric Jointly-Owned Facilities" in Item 2 herein for additional information. Southern Power has PPAs with Georgia Power, investor-owned utilities, IPPs, municipalities, electric cooperatives, and other load-serving entities, as well as commercial and industrial customers. See "The Southern Company System Southern Power" herein and MANAGEMENT'S DISCUSSION AND ANALYSIS FUTURE EARNINGS POTENTIAL "Southern Power's Power Sales Agreements" in Item 7 herein for additional information. SCS, acting on behalf of the traditional electric operating companies, also has a contract with SEPA providing for the use of the traditional electric operating companies' facilities at government expense to deliver to certain cooperatives and municipalities, entitled by federal statute to preference in the purchase of power from SEPA, quantities of power equivalent to the amounts of power allocated to them by SEPA from certain U.S. government hydroelectric projects. I-7 Index to Financial Statements Southern Company Gas Southern Company Gas is engaged in the distribution of natural gas in four states through the natural gas distribution utilities. The natural gas distribution utilities construct, manage, and maintain intrastate natural gas pipelines and distribution facilities. Details of the natural gas distribution utilities at December 31, 2022 are as follows: ##TABLE_START Utility State Number of customers Approximate miles of pipe (in thousands) Nicor Gas Illinois 2,268 34.7 Atlanta Gas Light Georgia 1,707 35.3 Virginia Natural Gas Virginia 312 5.9 Chattanooga Gas Tennessee 71 1.7 Total 4,358 77.6 ##TABLE_ENDFor information relating to the sources of revenue for Southern Company Gas, see Item 7 herein and Note 1 to the financial statements under "Revenues Southern Company Gas" and Note 4 to the financial statements in Item 8 herein. Competition Electric The electric utility industry in the U.S. is continuing to evolve as a result of regulatory and competitive factors. The competition for retail energy sales among competing suppliers of energy is influenced by various factors, including price, availability, technological advancements, service, and reliability. These factors are, in turn, affected by, among other influences, regulatory, political, and environmental considerations, taxation, and supply. The retail service rights of all electric suppliers in the State of Georgia are regulated by the Territorial Electric Service Act of 1973. Pursuant to standards set forth in this Act, the Georgia PSC has assigned substantially all of the land area in the state to a supplier. Notwithstanding such assignments, this Act provides that any new customer locating outside of 1973 municipal limits and having a connected load of at least 900 KWs may exercise a one-time choice for the life of the premises to receive electric service from the supplier of its choice. Pursuant to the 1956 Utility Act, the Mississippi PSC issued "Grandfather Certificates" of public convenience and necessity to Mississippi Power and to six distribution rural cooperatives operating in southeastern Mississippi, then served in whole or in part by Mississippi Power, authorizing them to distribute electricity in certain specified geographically described areas of the state. The six cooperatives serve approximately 325,000 retail customers in a certificated area of approximately 10,300 square miles. In areas included in a "Grandfather Certificate," the utility holding such certificate may extend or maintain its electric system subject to certain regulatory approvals; extensions of facilities by such utility, or extensions of facilities into that area by other utilities, may not be made unless the Mississippi PSC grants a CPCN. Areas included in a CPCN that are subsequently annexed to municipalities may continue to be served by the holder of the CPCN, irrespective of whether it has a franchise in the annexing municipality. On the other hand, the holder of the municipal franchise may not extend service into such newly annexed area without authorization by the Mississippi PSC. Generally, the traditional electric operating companies have experienced, and expect to continue to experience, competition in their respective retail service territories in varying degrees from the development and deployment of alternative energy sources such as self-generation (as described below) and distributed generation technologies, as well as other factors. Further technological advancements or the implementation of policies in support of alternative energy sources may result in further competition. Southern Power competes with investor-owned utilities, IPPs, and others for wholesale energy sales across various U.S. utility markets. The needs of these markets are driven by the demands of end users and the generation available. Southern Power's success in wholesale energy sales is influenced by various factors including reliability and availability of Southern Power's plants, availability of transmission to serve the demand, price, and Southern Power's ability to contain costs. As of December 31, 2022, Alabama Power had cogeneration contracts in effect with seven industrial customers. Under the terms of these contracts, Alabama Power purchases excess energy generated by such companies. During 2022, Alabama Power purchased approximately 68 million KWHs from such companies. The related costs were immaterial. I-8 Index to Financial Statements As of December 31, 2022, Georgia Power had contracts in effect to purchase generation from 39 small IPPs. During 2022, Georgia Power purchased 6.1 billion KWHs from such companies at a cost of $298 million. Georgia Power also has PPAs for electricity with five cogeneration facilities. Payments are subject to reductions for failure to meet minimum capacity output. During 2022, Georgia Power purchased 399 million KWHs at a cost of $37 million from these facilities. As of December 31, 2022, Mississippi Power had a cogeneration agreement in effect with one of its industrial customers. Under the terms of this contract, Mississippi Power purchases any excess generation. During 2022, Mississippi Power did not make any such purchases. Natural Gas Southern Company Gas' natural gas distribution utilities do not compete with other distributors of natural gas in their exclusive franchise territories but face competition from other energy products. Their principal competitors are electric utilities and fuel oil and propane providers serving the residential, commercial, and industrial markets in their service areas for customers who are considering switching to or from a natural gas appliance. Competition for heating as well as general household and small commercial energy needs generally occurs at the initial installation phase when the customer or builder makes decisions as to which types of equipment to install. Customers generally use the chosen energy source for the life of the equipment. Customer demand for natural gas could be affected by numerous factors, including: changes in the availability or price of natural gas and other forms of energy; general economic conditions; energy conservation, including state-supported energy efficiency programs; legislation and regulations, including certain bans on the use of natural gas in new or existing construction and electrification initiatives; the cost and capability to convert from natural gas to alternative energy products; and technological or regulatory changes resulting in displacement or replacement of natural gas appliances. Southern Company Gas has natural gas-related programs that generally emphasize natural gas as the fuel of choice for customers and seek to expand the use of natural gas through a variety of promotional activities. In addition, Southern Company Gas partners with third-party entities to market the benefits of natural gas appliances. Seasonality and Demand The demand for electric power and natural gas supply is affected by seasonal differences in the weather. While the electric power sales of some electric utilities peak in the summer, others peak in the winter. In the aggregate, during normal weather conditions, the Southern Company system's electric power sales peak during both the summer and winter. In most of the areas Southern Company Gas serves, natural gas demand peaks during the winter. As a result, the overall operating results of the Registrants in the future may fluctuate substantially on a seasonal basis. In addition, the Subsidiary Registrants have historically sold less power and natural gas when weather conditions are milder. See MANAGEMENT'S DISCUSSION AND ANALYSIS FUTURE EARNINGS POTENTIAL "General" and RESULTS OF OPERATIONS "Southern Company Gas Seasonality of Results" in Item 7 herein for information regarding trends in market demand for electricity and natural gas and the impact of seasonality on Southern Company Gas' business, respectively. Regulation States The traditional electric operating companies and the natural gas distribution utilities are subject to the jurisdiction of their respective state PSCs or applicable state regulatory agencies. These regulatory bodies have broad powers of supervision and regulation over public utilities operating in the respective states, including their rates, service regulations, sales of securities (except for the Mississippi PSC), and, in the cases of the Georgia PSC and the Mississippi PSC, in part, retail service territories. See "Territory Served by the Southern Company System" and "Rate Matters" herein for additional information. Federal Power Act The traditional electric operating companies, Southern Power Company and certain of its generation subsidiaries, and SEGCO are all public utilities engaged in wholesale sales of energy in interstate commerce and, therefore, are subject to the rate, financial, and accounting jurisdiction of the FERC under the Federal Power Act. The FERC must approve certain financings and allows an "at cost standard" for services rendered by system service companies such as SCS and Southern Nuclear. The I-9 Index to Financial Statements FERC is also authorized to establish regional reliability organizations which enforce reliability standards, address impediments to the construction of transmission, and prohibit manipulative energy trading practices. Alabama Power and Georgia Power are also subject to the provisions of the Federal Power Act or the earlier Federal Water Power Act applicable to licensees with respect to their hydroelectric developments. As of December 31, 2022, among the hydroelectric projects subject to licensing by the FERC are 14 existing Alabama Power generating stations having an aggregate installed capacity of 1.7 million KWs and 17 existing Georgia Power generating stations and one generating station partially owned by Georgia Power, with a combined aggregate installed capacity of 1.1 million KWs. In 2013, the FERC issued a new 30-year license to Alabama Power for Alabama Power's seven hydroelectric developments on the Coosa River (Weiss, Henry, Logan Martin, Lay, Mitchell, Jordan, and Bouldin). Alabama Power filed a petition requesting rehearing of the FERC order granting the relicense seeking revisions to several conditions of the license. In 2016, the FERC issued an order granting in part and denying in part Alabama Power's rehearing request. American Rivers and Alabama Rivers Alliance also filed multiple appeals of the FERC's 2013 order for the new 30-year license and, in 2018, the U.S. Court of Appeals for the District of Columbia Circuit vacated the order and remanded the proceeding to the FERC. Alabama Power continues to operate the Coosa River developments under annual licenses issued by the FERC. In November 2021, Alabama Power filed an application with the FERC to relicense the Harris Dam project on the Tallapoosa River. The current Harris Dam project license will expire on November 30, 2023. In 2018, Georgia Power filed applications to surrender the Langdale and Riverview hydroelectric projects on the Chattahoochee River upon their license expirations on December 31, 2023. Both projects together represent 1,520 KWs of Georgia Power's hydro fleet capacity. In December 2021, Georgia Power filed an application with the FERC to relicense the Lloyd Shoals project on the Ocmulgee River. The current Lloyd Shoals project license will expire on December 31, 2023. Georgia Power and OPC also have a license, expiring in 2026, for the Rocky Mountain project, a pure pumped storage facility of 903,000 KW installed capacity. In December 2021, OPC, as an agent for co-licensees of the project, filed a notice of intent with the FERC to relicense the project. An application to relicense the project is expected to be filed with the FERC by December 31, 2024. See PROPERTIES "Electric Jointly-Owned Facilities" in Item 2 herein for additional information. Licenses for all projects, excluding those discussed above, expire in the years 2034-2066 for Alabama Power's projects and in the years 2034-2060 for Georgia Power's projects. Upon or after the expiration of each license, the U.S. Government, by act of Congress, may take over the project or the FERC may relicense the project either to the original licensee or to a new licensee. In the event of takeover or relicensing to another, the original licensee is to be compensated in accordance with the provisions of the Federal Power Act, such compensation to reflect the net investment of the licensee in the project, not in excess of the fair value of the property, plus reasonable damages to other property of the licensee resulting from the severance therefrom of the property. The FERC may grant relicenses subject to certain requirements that could result in additional costs. The ultimate outcome of these matters cannot be determined at this time. Nuclear Regulation Alabama Power, Georgia Power, and Southern Nuclear are subject to regulation by the NRC. The NRC is responsible for licensing and regulating nuclear facilities and materials and for conducting research in support of the licensing and regulatory process, as mandated by the Atomic Energy Act of 1954, as amended; the Energy Reorganization Act of 1974, as amended; and the Nuclear Nonproliferation Act of 1978, as amended; and in accordance with the National Environmental Policy Act of 1969, as amended, and other applicable statutes. These responsibilities also include protecting public health and safety, protecting the environment, protecting and safeguarding nuclear materials and nuclear power plants in the interest of national security, and assuring conformity with antitrust laws. The NRC licenses for Georgia Power's Plant Hatch Units 1 and 2 expire in 2034 and 2038, respectively. On August 31, 2022, Southern Nuclear notified the NRC of its intent in 2025 to seek to renew the plant's licenses for an additional 20 years (through 2054 and 2058 for Units 1 and 2, respectively). The NRC licenses for Alabama Power's Plant Farley Units 1 and 2 expire in 2037 and 2041, respectively. The NRC licenses for Plant Vogtle Units 1 and 2 expire in 2047 and 2049, respectively. In 2012, the NRC issued combined construction and operating licenses (COLs) for Plant Vogtle Units 3 and 4. Receipt of the COLs allowed full construction to begin. On August 3, 2022, the NRC published its 103(g) finding that the acceptance criteria in the COL for Unit 3 had been met, which allowed nuclear fuel to be loaded and start-up testing to begin. See Note 2 to the financial statements under "Georgia Power Nuclear Construction" in Item 8 herein for additional information. I-10 Index to Financial Statements See Notes 3 and 6 to the financial statements under "Nuclear Insurance" and "Nuclear Decommissioning," respectively, in Item 8 herein for additional information. Environmental Laws and Regulations See "Construction Programs" herein, MANAGEMENT'S DISCUSSION AND ANALYSIS FUTURE EARNINGS POTENTIAL "Environmental Matters" in Item 7 herein, and Note 3 to the financial statements under "Environmental Remediation" and Note 6 to the financial statements in Item 8 herein for information concerning environmental laws and regulations impacting the Registrants. Rate Matters Rate Structure and Cost Recovery Plans Electric The rates and service regulations of the traditional electric operating companies are uniform for each class of service throughout their respective retail service territories. Rates for residential electric service are generally of the block type based upon KWHs used and include minimum charges. Residential and other rates contain separate customer charges. Rates for commercial service are also of the block type and, for large customers, the billing demand is generally used to determine capacity and minimum bill charges. These large customers' rates are generally based upon usage by the customer and include rates with special features to encourage off-peak usage. Additionally, Alabama Power and Mississippi Power are generally allowed by their respective state PSCs to negotiate the terms and cost of service to large customers, subject to final state PSC approval. The traditional electric operating companies recover certain costs through a variety of forward-looking, cost-based rate mechanisms. Fuel and net purchased energy costs are recovered through specific fuel cost recovery provisions. These fuel cost recovery provisions are adjusted to reflect increases or decreases in such costs as needed or on schedules as required by the respective PSCs. Approved compliance, storm damage, and certain other costs are recovered at Alabama Power and Mississippi Power through specific cost recovery mechanisms approved by their respective PSCs. Certain similar costs at Georgia Power are recovered through various base rate tariffs as approved by the Georgia PSC. Costs not recovered through specific cost recovery mechanisms are recovered at Alabama Power and Mississippi Power through annual, formulaic cost recovery proceedings and at Georgia Power through periodic base rate proceedings. See Note 2 to the financial statements in Item 8 herein for a discussion of rate matters and certain cost recovery mechanisms. Also see "Integrated Resource Planning" herein for additional information. The traditional electric operating companies and Southern Power Company and certain of its generation subsidiaries are authorized by the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate. Mississippi Power provides service under long-term contracts with rural electric cooperative associations and a municipality located in southeastern Mississippi under requirements cost-based electric tariffs, which are subject to regulation by the FERC. The contracts with these wholesale customers represented 12.4% of Mississippi Power's total operating revenues in 2022. Historically, these wholesale customers have acted as a group and any changes in contractual relationships for one customer are likely to be followed by the other wholesale customers. Natural Gas Southern Company Gas' natural gas distribution utilities are subject to regulation and oversight by their respective state regulatory agencies. Rates charged to customers vary according to customer class (residential, commercial, or industrial) and rate jurisdiction. These agencies approve rates designed to provide the opportunity to generate revenues to recover all prudently-incurred costs, including a return on rate base sufficient to pay interest on debt and provide a reasonable ROE. With the exception of Atlanta Gas Light, the earnings of the natural gas distribution utilities can be affected by customer consumption patterns that are largely a function of weather conditions and price levels for natural gas. The natural gas distribution utilities have weather or revenue normalization mechanisms that mitigate revenue fluctuations from customer consumption changes. Atlanta Gas Light operates in a deregulated environment in which Marketers rather than a traditional utility sell natural gas to end-use customers and earns revenue by charging rates to its customers based primarily on monthly fixed charges that are set by the Georgia PSC. In addition to natural gas cost recovery mechanisms, other cost recovery mechanisms and regulatory riders, which vary by utility, allow recovery of certain costs, such as those related to infrastructure replacement programs as well as environmental remediation, energy efficiency plans, and bad debts. I-11 Index to Financial Statements See Note 2 to the financial statements under "Southern Company Gas" in Item 8 herein for a discussion of rate matters and certain cost recovery mechanisms. Integrated Resource Planning Each of the traditional electric operating companies continually evaluates its electric generating resources in order to ensure that it maintains a cost-effective and reliable mix of resources to meet the existing and future demand requirements of its customers. See MANAGEMENT'S DISCUSSION AND ANALYSIS FUTURE EARNINGS POTENTIAL "Environmental Matters" in Item 7 herein for a discussion of existing and potential environmental regulations that may impact the future generating resource needs of the traditional electric operating companies, as well as a discussion of the Southern Company system's continued generating fleet transition. Alabama Power Triennially, Alabama Power provides an IRP report to the Alabama PSC. This report overviews Alabama Power's resource planning process and contains information that serves as the foundation for certain decisions affecting Alabama Power's portfolio of supply-side and demand-side resources. The IRP report facilitates Alabama Power's ability to provide reliable and cost-effective electric service to customers, while accounting for the risks and uncertainties inherent in planning for resources sufficient to meet expected customer demand. Under State of Alabama law, a CCN must be obtained from the Alabama PSC before Alabama Power constructs any new generating facility, unless such construction is an ordinary extension of an existing system in the usual course of business. Alabama Power provided its most recent IRP to the Alabama PSC during 2022. On July 12, 2022, the Alabama PSC approved a CCN authorizing Alabama Power to complete the acquisition of the Calhoun Generating Station. The transaction closed on September 30, 2022. During 2022, Alabama Power continued construction of Plant Barry Unit 8, which is expected to be placed in service in November 2023. See Note 2 to the financial statements under "Alabama Power Certificates of Convenience and Necessity" in Item 8 herein for additional information. Georgia Power Triennially, Georgia Power must file an IRP with the Georgia PSC that specifies how it intends to meet the future electric service needs of its customers through a combination of demand-side and supply-side resources. The Georgia PSC, under state law, must certify any new demand-side or supply-side resources for Georgia Power to receive cost recovery. Once certified, the lesser of actual or certified construction costs and purchased power costs is recoverable through rates. Certified costs may be excluded from recovery only on the basis of fraud, concealment, failure to disclose a material fact, imprudence, or criminal misconduct. On July 21, 2022, the Georgia PSC approved Georgia Power's 2022 IRP, as modified by a stipulated agreement among Georgia Power, the staff of the Georgia PSC, and certain intervenors and as further modified by the Georgia PSC. See Note 2 to the financial statements under "Georgia Power Integrated Resource Plans" and " Rate Plans" in Item 8 herein for additional information. Also see Note 2 to the financial statements under "Georgia Power Nuclear Construction" in Item 8 herein for additional information on the Georgia Nuclear Energy Financing Act and the Georgia PSC certification of Plant Vogtle Units 3 and 4, which allow Georgia Power to recover certain financing costs for construction of Plant Vogtle

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Units 3 and 4. Mississippi Power Triennially, Mississippi Power must file an IRP with the Mississippi PSC, as well as an update at approximately the mid-point of the three-year cycle. The IRP must include long-term plans to best meet the needs of electric utility customers through a combination of demand-side and supply-side resources and considering transmission needs. The IRP filing is not intended to supplant or replace the Mississippi PSC's existing regulatory processes for petition and approval of CPCNs for new generating resources. Mississippi Power's most recent IRP was filed in 2021 and the next IRP is scheduled to be filed in April 2024. Mississippi Power must also file an annual report on energy delivery improvements, the latest of which was filed on December 1, 2022. See Note 2 to the financial statements under "Mississippi Power Integrated Resource Plan" in Item 8 herein for additional information. I-12 Index to Financial Statements Human Capital Southern Company system management is committed to attracting, developing, and retaining a sustainable workforce and aims to foster a diverse, equitable, inclusive, and innovative culture. The Southern Company system's values safety first, unquestionable trust, superior performance, and total commitment guide behavior. The Southern Company system had approximately 27,700 employees on its payroll at December 31, 2022 comprised of the following: ##TABLE_START At December 31, 2022 (*) Alabama Power 6,100 Georgia Power 6,600 Mississippi Power 1,000 Southern Power 500 Southern Company Gas 4,600 SCS 4,000 Southern Nuclear 3,800 PowerSecure and other 1,100 Total Southern Company system 27,700 ##TABLE_END(*) Numbers are rounded to 100s. All Southern Company system employees are located within the United States. Part-time employees represent less than 1% of total employees. Southern Company system management values a diverse, equitable, and inclusive workforce. Southern Company's subsidiaries have policies, programs, and processes to help ensure that all groups are represented, included, and fairly treated across all job levels. The Southern Company Board of Directors and management believe that diversity is important to provide different perspectives on risk, business strategy, and innovation. Southern Company management leads the Southern Company system's diversity, equity, and inclusion initiatives and employee recruitment, retention, and development efforts. The Board, principally through its Compensation and Talent Development Committee, oversees these efforts. Southern Company system management utilizes its "Moving to Equity" initiative that focuses on five key areas: talent, work environment, supplier inclusion, civic engagement, and community investment and social justice. This initiative demonstrates the Southern Company system's commitments, highlights key results, and tracks progress on long-term goals. Southern Company system management supports employee resource groups, diversity councils, mentoring programs, and inclusion teams to provide formal networks of colleagues that can help promote belonging, improve employee retention, and support development. At December 31, 2022, people of color and women represented 30% and 26%, respectively, of the Southern Company system's workforce. Southern Company system management recognizes the importance of attracting and retaining an appropriately qualified workforce. Southern Company system management uses a variety of strategies to attract and retain talent, including working with high schools, technical schools, universities, and military installations to fill many entry-level positions. The recruiting strategy also includes partnerships with professional associations and local communities to recruit mid-career talent. The addition of external hires augments the existing workforce to meet changing business needs, address any critical skill gaps, and supplement and diversify the Southern Company system's talent pipeline. The Southern Company system supports the well-being of its employees through a comprehensive total rewards strategy with three measurable categories: physical, financial, and emotional well-being. The Southern Company system provides competitive salaries, annual incentive awards for nearly all employees, and health, welfare, and retirement benefits. The Southern Company system has a qualified defined benefit, trusteed pension plan and a qualified defined contribution, trusteed 401(k) plan which provides a competitive company matching contribution. Substantially all Southern Company system employees are eligible to participate in these plans. There are differences between the pension plan benefit formulas based on when and by which subsidiary an employee is hired. See Note 11 to the financial statements for additional information. At December 31, 2022, the average age of the Southern Company system employees was 45 and the average tenure with the Southern Company system was 15 years. Turnover rate, calculated as the percent of employees that terminated employment with the Southern Company system, including voluntary and involuntary terminations and retirements, divided by total employees, was 8.9%. Southern Company system management is committed to developing talent and helping employees succeed by providing development opportunities along with purposeful people moves as part of individual development plans and succession planning processes. The Southern Company system has multiple development programs, including programs targeted toward all I-13 Index to Financial Statements employees, high potential employees, first-level managers, managers of managers, and executives. Additionally, Southern Company system management strives to deliver consistent needs-based training and solutions as workplace needs evolve. Southern Company system management believes the safety of employees and customers is paramount. The Southern Company system seeks to meet or exceed applicable laws and regulations while continually improving its safety technologies and processes. The Southern Company System Safety and Health Council, which includes leaders from each Registrant, works collectively across the Southern Company system to provide safety leadership, share learning, work collaboratively to address safety-related issues, and govern the consistency of safety programs. The safety programs are focused on the prevention and elimination of life-altering events, serious injuries, and fatalities. These programs include continuous process improvements to put critical controls in place to prevent serious injuries, promote learning, and implement appropriate corrective actions. In 2022, the Southern Company system had zero fatalities and a serious injury rate of 0.05, which represents the number of incidents per 100 employees (calculated by taking the number of serious injuries multiplied by 200,000 workhours and divided by the total employee workhours during the year). A serious injury is one that is life-threatening or life-changing for the employee. Serious injury examples, as defined by applicable safety regulators, include fatalities, amputations, trauma to organs, certain bone fractures, severe burns, and eye injuries. The Southern Company system continues to provide essential services to customers while adapting to the impacts of the COVID-19 pandemic. The Southern Company system has implemented applicable safety and health guidelines issued by federal, state, and local officials, and established protocols for required work on customer premises. To date, these procedures have been effective in maintaining the Southern Company system's critical operations, while also emphasizing employee, customer, and community safety. The Southern Company system also has longstanding relationships with labor unions. The traditional electric operating companies, Southern Nuclear, and the natural gas distribution utilities have separate agreements with local unions of the IBEW, which generally apply to operating, maintenance, and construction employees. These agreements cover wages, benefits, terms of the pension plans, working conditions, and procedures for handling grievances and arbitration. The Southern Company system also partners with the IBEW to provide training programs to develop technical skills and career opportunities. At December 31, 2022, approximately 31% of Southern Company system employees were covered by agreements with unions, with agreements expiring between 2024 and 2026. I-14 Index to Financial Statements Item 1A. RISK FACTORS In addition to the other information in this Form 10-K, including MANAGEMENT'S DISCUSSION AND ANALYSIS FUTURE EARNINGS POTENTIAL in Item 7, and other documents filed by Southern Company and/or its subsidiaries with the SEC, the following factors should be carefully considered in evaluating Southern Company and its subsidiaries. Such factors could affect actual results and cause results to differ materially from those expressed in any forward-looking statements made by, or on behalf of, Southern Company and/or its subsidiaries. The risk factors discussed below could adversely affect a Registrant's results of operations, financial condition, liquidity, and cash flow, as well as cause reputational damage. UTILITY REGULATORY, LEGISLATIVE, AND LITIGATION RISKS Southern Company and its subsidiaries are subject to substantial federal, state, and local governmental regulation, including with respect to rates. Compliance with current and future regulatory requirements and procurement of necessary approvals, permits, and certificates may result in substantial costs to Southern Company and its subsidiaries. Laws and regulations govern the terms and conditions of the services the Southern Company system offers, protection of critical electric infrastructure assets, transmission planning, reliability, pipeline safety, interaction with wholesale markets, and relationships with affiliates, among other matters. The Registrants' businesses are subject to regulatory regimes which could result in substantial monetary penalties if a Registrant is found to be noncompliant. The profitability of the traditional electric operating companies' and the natural gas distribution utilities' businesses is largely dependent on their ability, through the rates that they are permitted to charge, to recover their costs and earn a reasonable rate of return on invested capital. The traditional electric operating companies and the natural gas distribution utilities seek to recover their costs, including a reasonable return on invested capital, through their retail rates, which must be approved by the applicable state PSC or other applicable state regulatory agency. Such regulators, in a future rate proceeding, may alter the timing or amount of certain costs for which recovery is allowed or modify the current authorized rate of return. Rate refunds may also be required. Additionally, the rates charged to wholesale customers by the traditional electric operating companies and Southern Power and the rates charged to natural gas transportation customers by Southern Company Gas' pipeline investments must be approved by the FERC. Changes to Southern Power's and the traditional electric operating companies' ability to conduct business pursuant to FERC market-based rate authority could affect wholesale rates. Also, while a small percentage of transmission revenues are collected through wholesale electric tariffs, the majority are collected through retail rates. Transmission planning could be impacted by FERC policy changes. The impact of any future revision or changes in interpretations of existing regulations or the adoption of new laws and regulations applicable to Southern Company or any of its subsidiaries is uncertain. Changes in regulation, the imposition of additional regulations, changes in enforcement practices of regulators, or penalties imposed for noncompliance with existing laws or regulations could influence the operating environment of the Southern Company system and may result in substantial costs. The Southern Company system's costs of compliance with environmental laws and satisfying related AROs are significant. The Southern Company system's operations are regulated by state and federal environmental agencies through a variety of laws and regulations governing air, GHGs, water, land, avian and other wildlife and habitat protection, and other natural resources. Compliance with existing environmental requirements involves significant capital and operating costs including the settlement of AROs, a major portion of which is expected to be recovered through retail and wholesale rates. There is no assurance, however, that all such costs will be recovered. The Registrants expect future compliance expenditures will continue to be significant. The EPA has adopted and is implementing regulations governing air and GHG emissions under the Clean Air Act and water quality under the Clean Water Act. The EPA and certain states have also adopted and continue to propose regulations governing the disposal and management of CCR at power plant sites. The cost estimates for AROs related to the disposal of CCR are based on information using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential compliance methods. The traditional electric operating companies will continue to periodically update their ARO cost estimates. Additionally, environmental laws and regulations covering the handling and disposal of waste and release of hazardous substances could require the Southern Company system to incur substantial costs to clean up affected sites, including certain current and former operating sites, and locations subject to contractual obligations. Litigation over environmental issues and claims of various types, including property damage, personal injury, and citizen enforcement of environmental requirements has occurred throughout the United States. This litigation has included, but is not I-15 Index to Financial Statements limited to, claims for damages alleged to have been caused by CO_2 and other emissions, CCR, releases of regulated substances, alleged exposure to regulated substances, and/or requests for injunctive relief in connection with such matters. Compliance with any new or revised environmental laws or regulations could affect many areas of operations for the Southern Company system. The Southern Company system's ultimate environmental compliance strategy and future environmental expenditures will depend on various factors, such as state adoption and implementation of requirements, the availability and cost of any deployed control technology, fuel prices, and the outcome of pending and/or future legal challenges. Compliance costs may result from the installation of additional environmental controls, closure and monitoring of CCR facilities, unit retirements, operational changes, or changing fuel sources for certain existing units, as well as related upgrades to the Southern Company system's transmission and distribution (electric and natural gas) systems. Environmental compliance spending over the next several years may differ materially from the amounts estimated and could adversely affect the Registrants if such costs cannot continue to be recovered on a timely basis. Further, increased costs that are recovered through regulated rates could contribute to reduced demand for electricity and natural gas. Additionally, many commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to reduce their demand for electricity or natural gas. The Southern Company system may be exposed to regulatory and financial risks related to the impact of GHG legislation, regulation, and emission reduction goals. Concern and activism about climate change continue to increase and, as a result, demand for energy conservation and sustainable assets could further increase. Additionally, costs associated with GHG legislation, regulation, and emission reduction goals could be significant. The Southern Company system has robust processes for identifying, assessing, and responding to climate-related risks, including a scenario planning process that is used to inform resource planning decisions in the states in which the traditional electric operating companies operate. This process relies on information from internal and external sources, which may or may not be accurate in predicting future outcomes. Each year, the Southern Company system develops scenarios which look out over a 30-year horizon. In 2022, scenarios included a wide range of fuel prices, load growth, and CO_2 prices starting between \$0 and \$50 per metric ton of CO_2 emitted and escalating over the 30-year horizon. Additional GHG policies, including legislation, may emerge requiring the United States to accelerate its transition to a lower GHG emitting economy. However, the ultimate impact will depend on various factors, such as state adoption and implementation of requirements, natural gas prices, the development, deployment, and advancement of relevant energy technologies, the ability to recover costs through existing ratemaking provisions, and the outcome of pending and/or future legal challenges. Because natural gas is a fossil fuel with lower carbon content relative to other fossil fuels, future carbon constraints, including, but not limited to, the imposition of a carbon tax, may create additional demand for natural gas, both for production of electricity and direct use in homes and businesses. However, such demand may be tempered by legislation limiting the use of natural gas in certain situations, such as new construction. Additionally, efforts to electrify the transportation and building sectors may result in higher electric demand and negatively impact natural gas demand. Future GHG constraints, including those related to methane emissions, designed to minimize emissions from natural gas could likewise result in increased costs to the Southern Company system and affect the demand for natural gas as well as the prices charged to customers and the competitive position of natural gas. Southern Company has established an intermediate goal of a 50% reduction in GHG emissions from 2007 levels by 2030 and a long-term goal of net zero GHG emissions by 2050. Achievement of these goals is dependent on many factors, including natural gas prices and the pace and extent of development and deployment of low- to no-GHG energy technologies and negative carbon concepts. The strategy to achieve these goals also relies on continuing to pursue a diverse portfolio including low-carbon and carbon-free resources and energy efficiency resources; continuing to transition the Southern Company system's generating fleet and making the necessary related investments in transmission and distribution systems; continuing research and development with a particular focus on technologies that lower GHG emissions, including methods of removing carbon from the atmosphere; and constructively engaging with policymakers, regulators, investors, customers, and other stakeholders to support outcomes leading to a net zero future. See MANAGEMENT'S DISCUSSION AND ANALYSIS FUTURE EARNINGS POTENTIAL "Environmental Matters Global Climate Issues" in Item 7 herein for additional information. I-16 Index to Financial Statements OPERATIONAL RISKS The financial performance of Southern Company and its subsidiaries may be adversely affected if the subsidiaries are unable to successfully operate their facilities or perform certain corporate functions. The financial performance of Southern Company and its subsidiaries depends on the successful operation of the electric generation, transmission, and distribution facilities, natural gas distribution facilities, and distributed generation storage technologies and the successful performance of necessary corporate functions. There are many risks that could affect these matters, including operator error or failure of equipment or processes, accidents, operating limitations that may be imposed by environmental or other regulatory requirements or in connection with joint owner arrangements, labor disputes, physical attacks, fuel or material supply interruptions and/or shortages, transmission disruption or capacity constraints, including with respect to the Southern Company system's and third parties' transmission, storage, and transportation facilities, inability to maintain reliability consistent with customer expectations as the traditional electric operating companies and Southern Power transition their generating fleets in support of the Southern Company system's net zero goal, compliance with mandatory reliability standards, including mandatory cyber security standards, implementation of new technologies, technology system failures, cyber intrusions, environmental events, such as spills or releases, supply chain disruptions, inflation, and catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, droughts, pandemic health events, political unrest, or other similar occurrences. Operation of nuclear facilities involves inherent risks, including environmental, safety, health, regulatory, natural disasters, cyber intrusions, physical attacks, and financial risks, that could result in fines or the closure of the nuclear units owned by Alabama Power or Georgia Power and which may present potential exposures in excess of insurance coverage. Alabama Power owns, and contracts for the operation of, two nuclear units and Georgia Power holds undivided interests in, and contracts for the operation of, four existing nuclear units. The six existing units are operated by Southern Nuclear and represented approximately 22% and 27% of the total KWHs generated by Alabama Power and Georgia Power, respectively, in the year ended December 31, 2022. In addition, Southern Nuclear, on behalf of Georgia Power and the other Vogtle Owners, is managing the construction and start-up of Plant Vogtle Units 3 and 4. Nuclear facilities are subject to environmental, safety, health, operational, and financial risks such as: the potential harmful effects on the environment and human health and safety resulting from a release of radioactive materials; uncertainties with respect to the ability to dispose of spent nuclear fuel and the need for longer term on-site storage; uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of licensed lives and the ability to maintain and anticipate adequate capital reserves for decommissioning; limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations; and significant capital expenditures relating to maintenance, operation, security, and repair of these facilities. Damages, decommissioning, or other costs could exceed the amount of decommissioning trusts or external insurance coverage, including statutorily required nuclear incident insurance. The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear facilities. In the event of non-compliance, the NRC has the authority to impose fines and/or shut down any unit, depending upon its assessment of the severity of the situation, until compliance is achieved. NRC orders or regulations related to increased security measures and any future NRC safety requirements could require Alabama Power and Georgia Power to make substantial operating and capital expenditures at their nuclear plants. In addition, if a serious nuclear incident were to occur, it could result in substantial costs to Alabama Power or Georgia Power and Southern Company. A major incident at a nuclear facility anywhere in the world could cause the NRC to delay or prohibit construction of new nuclear units or require additional safety measures at new and existing units. Moreover, a major incident at any nuclear facility in the United States, including facilities owned and operated by third parties, could require Alabama Power and Georgia Power to make material contributory payments. In addition, actual or potential threats of cyber intrusions or physical attacks could result in increased nuclear licensing or compliance costs. Transporting and storing natural gas involves risks that may result in accidents and other operating risks and costs. Southern Company Gas' natural gas distribution and storage activities involve a variety of inherent hazards and operating risks, such as leaks, accidents, explosions, and mechanical problems, which could result in serious injury, loss of life, significant damage to property, environmental pollution, and impairment of its operations. The location of pipelines and underground natural gas storage facilities near populated areas could increase the level of damage resulting from these risks. Additionally, pipelines and underground natural gas storage facilities are subject to various state and other regulatory requirements. Failure to comply with these requirements could result in substantial monetary penalties. I-17 Index to Financial Statements Physical attacks, both threatened and actual, could impact the ability of the Subsidiary Registrants to operate. The Subsidiary Registrants face the risk of physical attacks, both threatened and actual, against their respective generation and storage facilities and the transmission and distribution infrastructure used to transport energy, which could negatively impact their ability to generate, transport, and deliver power, or otherwise operate their respective facilities, or, with respect to Southern Company Gas, its ability to distribute or store natural gas, or otherwise operate its facilities, in the most efficient manner or at all. These risks may escalate during periods of heightened geopolitical tensions. In addition, physical attacks against third-party providers could have a similar effect on the Southern Company system. Despite the implementation of robust security measures, all assets are potentially vulnerable to disability, failures, or unauthorized access due to human error, natural disasters, technological failure, or internal or external physical attacks. If assets were to fail, be physically damaged, or be breached and were not restored in a timely manner, the affected Subsidiary Registrant may be unable to fulfill critical business functions. Insurance may not be adequate to cover any associated losses. An information security incident, including a cybersecurity breach, or the failure of, or inability to remotely access, one or more key technology systems, networks, or processes could impact the ability of the Registrants to operate. The Subsidiary Registrants operate in highly regulated industries that require the continued operation of sophisticated technology systems and network infrastructure, which are part of interconnected systems. Because of the critical nature of the infrastructure and the technology systems' inherent vulnerability to disability or failures due to hacking, viruses, denial of service, ransomware, acts of war or terrorism, or other types of data security breaches, the Southern Company system faces a heightened risk of cyberattack. Cyber actors, including those associated with foreign governments, have attacked and threatened to attack energy infrastructure. Various regulators have increasingly stressed that these attacks, including ransomware attacks, and attacks targeting utility systems and other critical infrastructure, are increasing in sophistication, magnitude, and frequency. Additionally, these risks may escalate during periods of heightened geopolitical tensions. The Registrants and their third-party vendors have been subject, and will likely continue to be subject, to attempts to gain unauthorized access to their technology systems and confidential data or to attempts to disrupt utility and related business operations. While there have been immaterial incidents of phishing, unauthorized access to technology systems, financial fraud, and disruption of remote access across the Southern Company system, there has been no material impact on business or operations from these attacks. However, the Registrants cannot guarantee that security efforts will detect or prevent breaches, operational incidents, or other breakdowns of technology systems and network infrastructure and cannot provide any assurance that such incidents will not have a material adverse effect in the future. In addition, in the ordinary course of business, Southern Company and its subsidiaries collect and retain sensitive information, including personally identifiable information about customers, employees, and stockholders, and other confidential information. In some cases, administration of certain functions may be outsourced to third-party service providers. Malicious actors may target these providers to disrupt the services they provide to the Registrants, or to use those third parties to attack the Registrants. The Registrants' third-party service providers could fail to establish adequate risk management and information security measures with respect to their systems. Internal or external cyber attacks may inhibit the affected Registrant's ability to fulfill critical business functions, including energy delivery service failures, compromise sensitive and other data, violate privacy laws, and lead to customer dissatisfaction. Any cyber breach or theft, damage, or improper disclosure of sensitive electronic data may also subject the affected Registrant to penalties and claims from regulators or other third parties. Insurance may not be adequate to cover any associated losses. Additionally, the cost and operational consequences of implementing, maintaining, and enhancing system protection measures are significant, and they could materially increase to address ever changing intense, complex, and sophisticated cyber risks. The Southern Company system may not be able to obtain adequate natural gas, fuel supplies, and other resources required to operate the traditional electric operating companies' and Southern Power's electric generating plants or serve Southern Company Gas' natural gas customers. SCS, on behalf of the traditional electric operating companies and Southern Power, purchases fuel for the Southern Company system's generation fleet from a diverse set of suppliers. Southern Company Gas' primary business is the distribution of natural gas through the natural gas distribution utilities. Natural gas is delivered daily from different regions of the country. This daily supply is complemented by natural gas supplies stored in both company-owned and third party storage locations. To deliver this daily supply and stored natural gas, the Southern Company system has firm transportation capacity contracted with third party interstate pipelines. Disruption in the supply and/or delivery of fuel as a result of matters such as transportation delays, weather, labor relations, force majeure events, or environmental regulations affecting fuel suppliers could limit the ability of the traditional electric operating companies and Southern Power to operate certain facilities, which could result in higher fuel and operating costs, and the ability of Southern Company Gas to serve its natural gas customers. I-18 Index to Financial Statements The Southern Company system is dependent upon natural gas as a fuel source for its power generation needs, which has the potential to impact, among other things, the traditional electric operating companies' and Southern Power's costs of generation. The robust growth in supply allowed natural gas prices to moderate and remain below $3 per mmBtu in recent years; however, demand increases beginning in 2021 and continuing in 2022 resulted in price increases and high volatility. The Henry Hub price averaged $6.38 per mmBtu in 2022. Current forecasts for 2023 are approximately $3.30. Forward market prices for 2024 and beyond indicate expectations, absent unforeseen developments, that prices will modestly increase. With the majority of natural gas production being from shale gas formations, any limitation on shale gas production would be expected to have a material impact on the supply availability as well as the cost of natural gas. In addition, new demand, in particular exports to Mexico and those from LNG facilities, has grown significantly and is having greater impact on the traditional electric operating companies' and Southern Power's natural gas markets. The traditional electric operating companies are also dependent on coal, and related coal supply contracts, for a portion of their electric generating capacity. The counterparties to coal supply contracts may not fulfill their obligations to supply coal because of financial or technical problems. In addition, the suppliers and/or railroads may be delayed in supplying or delivering or may not be required to supply or deliver coal under certain circumstances, such as in the event of a natural disaster. If the traditional electric operating companies are unable to obtain their contracted coal requirements, they may be required to purchase additional coal at higher prices or limit coal generation, and these increased costs may not be recoverable through rates if deemed to be imprudently incurred. The railroad industry has been experiencing labor shortages, which has led to delays in coal deliveries. As coal-fired generating facilities are retired, the demand for coal is expected to continue to decline. As a result, railroads may commit fewer resources to coal transportation, which could increase these risks. Whereas fuel oil directly provides only a small portion of the Southern Company system's annual generation, its importance to the reliability of the Southern Company system's generation portfolio continues to grow. Over the last few years, related cost increases and supply chain challenges have become more common and may increase the risk of reliability challenges. In addition to fuel supply, the traditional electric operating companies and Southern Power also need adequate access to water, which is drawn from nearby sources, to aid in the production of electricity. Any impact to their water resources could also limit the ability of the traditional electric operating companies and Southern Power to operate certain facilities, which could result in higher fuel and operating costs. The revenues of Southern Company, the traditional electric operating companies, and Southern Power depend in part on sales under PPAs, the success of which depend on PPA counterparties performing their obligations, Southern Company subsidiaries satisfying minimum requirements under the PPAs, and renewal or replacement of the PPAs for the related generating capacity. Most of Southern Power's generating capacity has been sold to purchasers under PPAs with Southern Power's top three customers comprising approximately 22% of Southern Power's total revenues for the year ended December

31, 2022. The traditional electric operating companies have entered into PPAs with non-affiliated parties for the sale of generating capacity. The revenues related to PPAs are dependent on the continued performance by the purchasers of their obligations. Although the credit evaluations undertaken and contractual protections implemented by Southern Power and the traditional electric operating companies take into account the possibility of default by a purchaser, actual exposure to a default by a purchaser may be greater than predicted or specified in the applicable contract. Additionally, neither Southern Power nor any traditional electric operating company can predict whether the PPAs will be renewed at the end of their respective terms or on what terms any renewals may be made. If one of these Registrants is unable to replace expiring PPAs with an acceptable new revenue contract, it may be required to sell the power produced by the facility at wholesale prices and be exposed to market fluctuations and risks, or the affected site may temporarily or permanently cease operations. The failure to satisfy minimum operational or availability requirements under these PPAs, including PPAs related to projects under construction, could result in payment of damages or termination of the PPAs. Increased competition from other companies that supply energy or generation and storage technologies and changes in customer demand for energy could negatively impact Southern Company and its subsidiaries. The traditional electric operating companies operate under a business model that invests capital to serve customers and recovers those investments and earns a return for investors through state regulation. Southern Power's business model is primarily focused on investing capital or building energy assets to serve creditworthy counterparties using a bilateral contract model. A key premise of these business models is that generating power at power plants achieves economies of scale and produces power at a competitive cost. Customers and stakeholders are increasingly focused on the Registrants' ability to meet rapidly changing demands for new and varied products, services, and offerings. Additionally, the risk of global climate change continues to shape customers' and stakeholders' sustainability goals and energy needs. I-19 Index to Financial Statements New technologies such as distributed energy resources and microgrids and increased customer and stakeholder demand for sustainable assets could change the type of assets constructed and/or the methods for cost recovery. Advances in these technologies or changes in laws or regulations could reduce the cost of distributed generation storage technologies or other alternative methods of producing power to a level that is competitive with that of most power generation production or result in smaller-scale, more fuel efficient, and/or more cost effective distributed generation that allows for increased self-generation by customers. Broader use of distributed generation by retail energy customers may also result from customers' changing perceptions of the merits of utilizing existing generation technology or tax or other economic incentives. Additionally, a state PSC or legislature may modify certain aspects of the traditional electric operating companies' business as a result of these advances in technology, which may provide for further competition from these alternative sources of generation. It is also possible that rapid advances in power generation technology could reduce the value of the current electric generating facilities owned by the traditional electric operating companies and Southern Power. Changes in technology could also alter the channels through which electric customers buy or utilize power. Southern Company Gas' business is dependent on natural gas prices remaining competitive as compared to other forms of energy. Southern Company Gas' gas marketing services segment also is affected by competition from other energy marketers providing similar services in Southern Company Gas' unregulated service territories, most notably in Illinois and Georgia. If new technologies become cost competitive and achieve sufficient scale, the market share of the Subsidiary Registrants could be eroded, and the value of their respective electric generating facilities or natural gas distribution facilities could be reduced. Additionally, these technology and customer-induced changes to the electric generation business models could change the risk profile of the Southern Company system's historical capital investments. Southern Company Gas' market share could be reduced if Southern Company Gas cannot remain price competitive in its unregulated markets. The Subsidiary Registrants are subject to workforce factors that could affect operations. The Southern Company system must attract, train, and retain a workforce to meet current and future needs. Events such as an aging workforce without appropriate replacements, increased cost or reduced supply of labor, mismatch of skill sets to future needs, or unavailability of contract resources may lead to operating challenges such as lack of resources, loss of knowledge, and a lengthy time period associated with skill development, including workforce needs associated with major construction projects and ongoing operations. The Southern Company system may be subject to workforce trends occurring in the United States triggered by decisions of employees to leave the workforce and/or their employer at higher rates as compared to prior years and challenges competing with other employers offering more flexible or fully-remote work options. The Southern Company system's costs, including costs for contractors to replace employees, productivity costs, and safety costs, may rise. Failure to hire and adequately obtain replacement employees, including the ability to transfer significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect Southern Company and its subsidiaries' ability to manage and operate their businesses. Supply chain disruptions and inflation could negatively impact operations. The Southern Company system's operations and business plans depend on the global supply chain to procure equipment, materials, and other resources. The delivery of components, materials, equipment, and other resources that are critical to the Southern Company system's operations has been impacted by ongoing domestic and global supply chain disruptions. International tensions, including the ramifications of regional conflict, could further exacerbate global supply chain disruptions. These disruptions and shortages could adversely impact business operations. The constraints in the supply chain also could restrict availability and delay construction, maintenance, or repair of items needed to support normal operations or to continue planned capital investments. Supply chain disruptions have contributed to higher prices of components, materials, equipment, and other needed commodities, and these inflationary increases may continue. While inflation in the United States had been relatively low in recent years, its impact became more significant during 2021 and continued in 2022. Uncertainty around inflationary impacts continues to increase in the near-term outlook for economic activity. Rapid inflation or other economic factors may negatively affect the timely recovery of costs. The impacts of the COVID-19 pandemic continue. The effects of the continued COVID-19 pandemic and related global, federal, state, and local responses could include new or extended disruptions to capital markets, further reduced labor availability and productivity, and new or prolonged reductions in economic activity. These effects could have a variety of adverse impacts on the Registrants, including, but not limited to, new or prolonged reductions in demand for energy, particularly from commercial and industrial customers, impairment of goodwill or long-lived assets, reductions in investments recorded at fair value, further increases in costs of necessary equipment, and further challenges to the development, construction, and/or operation of the Subsidiary Registrants' facilities, including electric I-20 Index to Financial Statements generation, transmission, and distribution assets, the performance of necessary corporate and customer service functions, and access to funds from financial institutions and capital markets. The effects of the COVID-19 pandemic also could further disrupt or delay construction, testing, supervisory, and support activities at Plant Vogtle Units 3 and 4, as discussed in Note 2 to the financial statements under "Georgia Power Nuclear Construction" in Item 8 herein. CONSTRUCTION RISKS The Registrants have incurred and may incur additional costs or delays in the construction of new plants or other facilities and may not be able to recover their investments. Also, existing facilities of the Subsidiary Registrants require ongoing expenditures, including those to meet AROs and other environmental standards and goals. The businesses of the Registrants require substantial expenditures for investments in new facilities as well as capital improvements, including transmission, distribution, and generation facilities for the traditional electric operating companies, generation facilities for Southern Power, and capital improvements to natural gas distribution facilities for Southern Company Gas. These expenditures also include those to settle AROs and meet environmental standards and goals. The traditional electric operating companies and Southern Power are in the process of constructing new generating facilities and/or adding environmental and other modifications to certain existing generating facilities and Southern Company Gas is replacing certain pipe in its natural gas distribution system. The traditional electric operating companies also are in the process of closing ash ponds to comply with the CCR Rule and, where applicable, state CCR rules. The Southern Company system intends to continue its strategy of developing and constructing new electric generating facilities, expanding and improving the electric transmission and electric and natural gas distribution systems, and undertaking projects to comply with environmental laws and regulations. These projects are long-term in nature and in some cases may include the development and construction of facilities with designs that have not been finalized or previously constructed. Completion of these types of projects without delays or significant cost overruns is subject to substantial risks that have occurred or may occur, including labor costs, availability, and productivity; challenges with the management of contractors or vendors; subcontractor performance; adverse weather conditions; shortages, delays, increased costs, or inconsistent quality of equipment, materials, and labor; contractor or supplier delay; the impacts of inflation; delays due to judicial or regulatory action; nonperformance under construction, operating, or other agreements; operational readiness, including specialized operator training and required site safety programs; engineering or design problems or any remediation related thereto; design and other licensing-based compliance matters including, for Plant Vogtle Unit 4, inspections and the timely submittal by Southern Nuclear of the ITAAC documentation and the related investigations, reviews, and approvals by the NRC necessary to support NRC authorization to load fuel; challenges with start-up activities, including major equipment failure, or system integration; and/or operational performance; continued challenges related to the COVID-19 pandemic or future pandemic health events; continued public and policymaker support for projects; environmental and geological conditions; delays or increased costs to interconnect facilities to transmission grids; and increased financing costs as a result of changes in interest rates or as a result of project delays. If a Subsidiary Registrant is unable to complete the development or construction of a project or decides to delay or cancel construction of a project, it may not be able to recover its investment in that project and may incur substantial cancellation payments under equipment purchase orders or construction contracts, as well as other costs associated with the closure and/or abandonment of the construction project. In addition, partnership and joint ownership agreements may provide partners or co-owners with certain decision-making authority in connection with projects under construction, including rights to change ownership allocations and/or cause the cancellation of a construction project under certain circumstances. Any failure by a partner or co-owner to perform its obligations under the applicable agreements could have a material negative impact on the applicable project under construction. Southern Power participates in partnership agreements with respect to a majority of its renewable energy projects and Georgia Power jointly owns Plant Vogtle Units 3 and 4 with other co-owners. See Note 5 to the financial statements under "Joint Ownership Agreements" in Item 8 herein for additional information regarding other jointly-owned facilities. If construction projects are not completed according to specification, a Registrant may incur liabilities and suffer reduced plant efficiency, higher operating costs, and reduced net income. Furthermore, construction delays associated with renewable projects could result in the loss of otherwise available tax credits and incentives. Even if a construction project (including a joint venture construction project) is completed, the total costs may be higher than estimated and may not be recoverable through regulated rates, if applicable. In addition, construction delays and contractor performance shortfalls can result in the loss of revenues. The largest construction project currently underway in the Southern Company system is Plant Vogtle Units 3 and

4. Southern Company and Georgia Power recorded total pre-tax charges to income of $3.3 billion ($2.4 billion after tax) through December 31, 2022 to reflect Georgia Power's revised estimate to complete I-21 Index to Financial Statements construction and start-up of Plant Vogtle Units 3 and 4. See Note 2 to the financial statements under "Georgia Power Nuclear Construction" in Item 8 herein for information regarding Plant Vogtle Units 3 and 4. Also see Note 2 to the financial statements under "Alabama Power Certificates of Convenience and Necessity" in Item 8 herein for information regarding Alabama Power's construction of Plant Barry Unit 8. Once facilities become operational, ongoing capital expenditures are required to maintain reliable levels of operation. Significant portions of the traditional electric operating companies' existing facilities were constructed many years ago. Older equipment, even if maintained in accordance with good engineering practices, may require significant expenditures to maintain efficiency, to comply with environmental requirements, to provide safe and reliable operations, and/or to meet related retirement obligations. FINANCIAL, ECONOMIC, AND MARKET RISKS The electric generation and energy marketing operations of the traditional electric operating companies and Southern Power and the natural gas operations of Southern Company Gas are subject to changes in energy prices and fuel costs. The generation, energy marketing, and natural gas operations of the Southern Company system are subject to changes in energy prices and fuel costs, which could increase the cost of producing power, decrease the amount received from the sale of energy, and/or make electric generating facilities and natural gas distribution systems less competitive. The market prices for these commodities may fluctuate significantly over relatively short periods of time as a result of changes in supply and/or demand, which could increase the expenses and/or reduce the revenues of the Registrants. For the traditional electric operating companies and Southern Company Gas' regulated gas distribution operations, such impacts may not be fully recoverable through rates. The traditional electric operating companies and Southern Company Gas from time to time have experienced and may continue to experience underrecovered fuel and/or purchased gas cost balances. While the traditional electric operating companies and Southern Company Gas are generally authorized to recover fuel and/or purchased gas costs through cost recovery clauses, recovery may be delayed or may be denied if costs are deemed to be imprudently incurred. The Registrants are subject to risks associated with a changing economic environment, customer behaviors, including increased energy conservation, and adoption patterns of technologies by the customers of the Subsidiary Registrants. The consumption and use of energy are linked to economic activity. This relationship is affected over time by changes in the economy, customer behaviors, and technologies. Any economic downturn could negatively impact customer growth and usage per customer. Additionally, any economic downturn or disruption of financial markets, both nationally and internationally, could negatively affect the financial stability of customers and counterparties of the Subsidiary Registrants. Outside of economic disruptions, changes in customer behaviors in response to energy efficiency programs, changing conditions and preferences,

legislation, or changes in the adoption of technologies could affect the relationship of economic activity to the consumption of energy. For example, some cities in the United States have banned the use of natural gas in new construction. Both federal and state programs exist to influence how customers use energy, and several of the traditional electric operating companies and natural gas distribution utilities have PSC or other applicable state regulatory agency mandates to promote energy efficiency. Customers could also voluntarily reduce their consumption of energy in response to decreases in their disposable income, increases in energy prices, or individual conservation efforts. In addition, the adoption of technology by customers can have both positive and negative impacts on sales. Many new technologies utilize less energy than in the past. However, electric and natural gas technologies such as electric and natural gas vehicles can create additional demand. The Southern Company system uses best available methods and experience to incorporate the effects of changes in customer behavior, state and federal programs, PSC or other applicable state regulatory agency mandates, and technology, but the Southern Company system's planning processes may not accurately estimate and incorporate these effects. The operating results of the Registrants are affected by weather conditions and may fluctuate on a seasonal basis. In addition, catastrophic events could result in substantial damage to or limit the operation of the properties of a Subsidiary Registrant. Electric power and natural gas supply are generally seasonal businesses. The Subsidiary Registrants have historically sold less power and natural gas when weather conditions are milder. Volatile or significant weather events could result in substantial damage to the transmission and distribution lines of the traditional electric operating companies, the generating facilities of the traditional electric operating companies and Southern I-22 Index to Financial Statements Power, and the natural gas distribution and underground storage facilities of Southern Company Gas, which is likely to negatively impact revenue. The Subsidiary Registrants have significant investments in the Atlantic and Gulf Coast regions and Southern Power and Southern Company Gas have investments in various states that could be subject to severe weather and natural disasters, including hurricanes and wildfires. Further, severe drought conditions can reduce the availability of water and restrict or prevent the operation of certain generating facilities. These volatile weather events may result in unexpected increases in customer load, requiring procurement of additional power at wholesale prices, or create other grid reliability issues. In the event a traditional electric operating company or Southern Company Gas experiences any of these weather events or any natural disaster or other catastrophic event, recovery of costs in excess of reserves and insurance coverage is subject to the approval of its state PSC or other applicable state regulatory agency. The traditional electric operating companies from time to time have experienced and may continue to experience deficits in their storm cost recovery reserve balances. Additionally, the applicable state PSC or other applicable state regulatory agency may deny or delay recovery of any portion of such costs. In addition, damages resulting from significant weather events occurring within a Subsidiary Registrant's service territory or otherwise affecting its customers may result in the loss of customers and reduced demand for energy for extended periods and may impact customers' ability to perform under existing PPAs. Acquisitions, dispositions, or other strategic ventures or investments may not result in anticipated benefits and may present risks, including risks not originally contemplated. Southern Company and its subsidiaries have made significant acquisitions, dispositions, and investments in the past and may continue to do so. Such actions cannot be assured to be completed or beneficial to Southern Company or its subsidiaries. Southern Company and its subsidiaries continually seek opportunities to create value through various transactions, including acquisitions or sales of assets. Specifically, Southern Power continually seeks opportunities to execute its strategy to create value through various transactions, including acquisitions, dispositions, and sales of partnership interests, development and construction of new generating facilities, and entry into PPAs primarily with investor-owned utilities, IPPs, municipalities, and other load-serving entities, as well as commercial and industrial customers. Additionally, Southern Company Gas has made significant investments in existing pipelines, most of which are operated by third parties. If one of these agents fails to perform in a proper manner, the value of the investment could decline and Southern Company Gas could lose part or all of its investment. In addition, Southern Company Gas is required to fulfill capital obligations to pipeline joint ventures. Southern Company and its subsidiaries may face significant competition for transactional opportunities and anticipated transactions may not be completed on acceptable terms or at all. In addition, these transactions are intended to, but may not, result in the generation of cash or income, the realization of savings, the creation of efficiencies, or the reduction of risk. These transactions also involve risks, including that they may not result in an increase in income or provide adequate or expected funds or return on capital or other anticipated benefits; they may result in Southern Company or its subsidiaries entering into new or additional lines of business, which may have new or different business or operational risks; they may not be successfully integrated into the acquiring company's operations, internal control processes, and/or accounting systems; the due diligence conducted prior to a transaction may not uncover situations that could result in financial or legal exposure or may not appropriately evaluate the likelihood or quantify the exposure from identified risks; they may result in decreased earnings, revenues, or cash flow; they may involve retained obligations in connection with transitional agreements or deferred payments related to dispositions that subject Southern Company or its subsidiaries to additional risk; Southern Company or the applicable subsidiary may not be able to achieve the expected financial benefits from the use of funds generated by any dispositions; expected benefits of a transaction may be dependent on the cooperation, performance, or credit risk of a counterparty; minority investments in growth companies may not result in a positive return on investment; or, for the traditional electric operating companies and Southern Company Gas, costs associated with such investments that were expected to be recovered through regulated rates may not be recoverable. Southern Company and Southern Company Gas are holding companies and Southern Power owns many of its assets indirectly through subsidiaries. Each of these companies is dependent on cash flows from their respective subsidiaries to meet their ongoing and future financial obligations. Southern Company and Southern Company Gas are holding companies and, as such, they have no operations of their own. Substantially all of Southern Company's and Southern Company Gas' and many of Southern Power's respective consolidated assets are held by subsidiaries. Southern Company's, Southern Company Gas' and, to a certain extent, Southern Power's ability to meet their respective financial obligations, including making interest and principal payments on outstanding indebtedness, and, for Southern Company, to pay dividends on its common stock, is dependent on the net income and cash flows of their respective subsidiaries and the ability of those subsidiaries to pay upstream dividends or to repay borrowed funds. Prior to funding Southern Company, Southern Company Gas, or Southern Power, the respective subsidiaries have financial obligations and, with respect to Southern Company and Southern Company Gas, regulatory restrictions that must be satisfied, including among others, debt service. In addition, Southern Company, Southern Company Gas, and Southern Power may provide capital I-23 Index to Financial Statements contributions or debt financing to subsidiaries under certain circumstances, which would reduce the funds available to meet their respective financial obligations, including making interest and principal payments on outstanding indebtedness, and to pay dividends on Southern Company's common stock. A downgrade in the credit ratings of any of the Registrants, Southern Company Gas Capital, or Nicor Gas could negatively affect their ability to access capital at reasonable costs and/or could require posting of collateral or replacing certain indebtedness. There are numerous factors that rating agencies evaluate to arrive at credit ratings for the Registrants, Southern Company Gas Capital, and Nicor Gas, including capital structure, regulatory environment, the ability to cover liquidity requirements, other commitments for capital, and certain other controllable and uncontrollable events. The Registrants, Southern Company Gas Capital, and Nicor Gas could experience a downgrade in their ratings if any rating agency concludes that the level of business or financial risk of the industry or the applicable company has deteriorated. Changes in ratings methodologies by the agencies could also have a negative impact on credit ratings. If one or more rating agencies downgrade any Registrant, Southern Company Gas Capital, or Nicor Gas, borrowing costs likely would increase, including potential automatic increases in interest rates or fees under applicable term loans and credit facilities, the pool of investors and funding sources would likely decrease, and, particularly for any downgrade to below investment grade, significant collateral requirements may be triggered in a number of contracts. Any credit rating downgrades could require altering the mix of debt financing currently used and could require the issuance of secured indebtedness and/or indebtedness with additional restrictive covenants binding the applicable company. Uncertainty in demand for energy can result in lower earnings or higher costs. The traditional electric operating companies and Southern Power each engage in a long-term planning process to estimate the optimal mix and timing of new generation assets required to serve future load obligations. Southern Company Gas engages in a long-term planning process to estimate the optimal mix and timing of building new pipelines, replacing existing pipelines, and entering new markets and/or expanding in existing markets. These planning processes must project many years into the future to accommodate the long lead times associated with the permitting and construction of new generation and associated transmission facilities and natural gas distribution facilities. Inherent risk exists in predicting demand as future loads are dependent on many uncertain factors, including economic conditions, customer usage patterns, efficiency programs, and customer technology adoption. Because regulators may not permit the traditional electric operating companies or the natural gas distribution utilities to adjust rates to recover the costs of new generation and associated transmission assets and/or new pipelines and related infrastructure in a timely manner or at all, these subsidiaries may not be able to fully recover these costs or may have exposure to regulatory lag associated with the time between the incurrence of costs and the recovery in customers' rates. In addition, under Southern Power's model of selling capacity and energy at negotiated market-based rates under long-term PPAs, Southern Power might not be able to fully execute its business plan if market prices drop below original forecasts. Southern Power and/or the traditional electric operating companies may not be able to extend or replace existing PPAs upon expiration, or they may be forced to market these assets at prices lower than originally intended. The traditional electric operating companies are currently obligated to supply power to retail customers and wholesale customers under long-term PPAs. Southern Power is currently obligated to supply power to wholesale customers under long-term PPAs. At peak times, the demand for power required to meet this obligation could exceed the Southern Company system's available generation capacity. Market or competitive forces may require that the traditional electric operating companies purchase capacity in the open market or build additional generation and transmission facilities and that Southern Power purchase energy or capacity in the open market. Because regulators may not permit the traditional electric operating companies to pass all of these purchase or construction costs on to their customers, the traditional electric operating companies may not be able to recover some or all of these costs or may have exposure to regulatory lag associated with the time between the incurrence of costs of purchased or constructed capacity and the traditional electric operating companies' recovery in customers' rates. Under Southern Power's long-term fixed price PPAs, Southern Power may not be able to recover all of these costs. I-24 Index to Financial Statements The businesses of the Registrants and Nicor Gas are dependent on their ability to successfully access capital through capital markets and financial institutions. The Registrants and Nicor Gas rely on access to both short-term and longer-term capital markets as a significant source of liquidity to meet capital requirements not satisfied by the cash flow from their respective operations. If any of the Registrants or Nicor Gas is not able to access capital at competitive rates or on favorable terms, its ability to implement its business plan will be limited due to weakened capacity to fund capital investments or acquisitions that it may otherwise rely on to achieve future earnings and cash flows. In addition, the Registrants and Nicor Gas rely on committed credit facilities as back-up liquidity for access to low cost money markets. Certain market disruptions, including an economic downturn or uncertainty, continued increases in interest rates, bankruptcy or financial distress at an unrelated utility company, financial institution, or sovereign entity, capital markets volatility and disruption, either nationally or internationally, changes in tax policy, volatility in market prices for electricity and natural gas, actual or threatened cyber or physical attacks on facilities within the Southern Company system or owned by unrelated utility companies, future impacts of the COVID-19 pandemic or other pandemic health events, war or threat of war, or the overall health of the utility and financial institution industries, may increase the cost of borrowing or adversely affect the ability to raise capital through the issuance of securities or other borrowing arrangements or the ability to secure committed bank lending agreements used as back-up sources of capital. Furthermore, some financial institutions may be limited in their ability to provide capital to the Registrants as a result of such financial institution's investment criteria, including criteria related to GHG. Additionally, since a portion of the Registrants' and Southern Company Gas Capital's indebtedness bears interest at variable rates based on LIBOR, uncertainty related to its announced phase out and alternative reference rates may adversely affect financing costs. Any replacement benchmark rates may be relatively new, fundamentally different from LIBOR, and/or more volatile than other benchmark or market rates. SOFR has been identified as the current replacement benchmark rate for LIBOR in the United States, although the SOFR market is not yet fully developed. If sources of capital for the Registrants or Nicor Gas are reduced, capital costs could increase materially. Failure to comply with debt covenants or conditions could adversely affect the ability of the Registrants, SEGCO, Southern Company Gas Capital, or Nicor Gas to execute future borrowings. The debt and credit agreements of the Registrants, SEGCO, Southern Company Gas Capital, and Nicor Gas contain various financial and other covenants. Georgia Power's loan guarantee agreement with the DOE contains additional covenants, events of default, and mandatory prepayment events relating to the construction of Plant Vogtle Units 3 and 4. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. Volatility in the securities markets, interest rates, and other factors could substantially increase defined benefit pension and other postretirement plan costs and the funding available for nuclear decommissioning. The costs of providing pension and other postretirement benefit plans are dependent on a number of factors, such as the rates of return on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plan, changes in actuarial assumptions, government regulations, and/or life expectancy, and the frequency and amount of the Southern Company system's required or voluntary contributions made to the plans. Changes in actuarial assumptions and differences between the assumptions and actual values, as well as a significant decline in the value of investments that fund the pension and other postretirement plans, if not offset or mitigated by a decline in plan liabilities, could increase pension and other postretirement expense, and the Southern Company system could be required from time to time to fund the pension plans with significant amounts of cash. See MANAGEMENT'S DISCUSSION AND ANALYSIS ACCOUNTING POLICIES "Application of Critical Accounting Policies and Estimates Pension and Other Postretirement Benefits" in Item 7 herein and Note 11 to the financial statements in Item 8 herein for additional information regarding the defined benefit pension and other postretirement plans. Additionally, Alabama Power and Georgia Power each hold significant assets in their nuclear decommissioning trusts to satisfy obligations to decommission their nuclear plants. The rate of return on assets held in those trusts can significantly impact both the funding available for decommissioning and the funding requirements for the trusts. See Note 6 to the financial statements under "Nuclear Decommissioning" in Item 8 herein for additional information. Shareholder activism could cause Southern Company to incur significant expense, hinder execution of Southern Company's business strategy, and impact Southern Company's stock price. Shareholder activism, which can take many forms and arise in a variety of situations, could result in substantial costs and divert management's and Southern Company's board's attention and resources. Additionally, such shareholder activism could give rise to perceived uncertainties as to Southern Company's future, adversely affect the Southern Company system's relationships with its employees, customers, regulators, or service providers, and make it more difficult to attract and retain qualified personnel. Also, Southern Company may be required to incur significant fees and other expenses related to activist shareholder matters, I-25 Index to Financial Statements including for third-party advisors. Southern Company's stock price could be subject to significant fluctuation or otherwise be adversely affected by the events, risks, and uncertainties of any shareholder activism. The Registrants are subject to risks associated with their ability to obtain adequate insurance at acceptable costs. The financial condition of some insurance companies, actual or threatened physical or cyber attacks, natural disasters, and an increased focus on climate issues, among other things, could have disruptive effects on insurance markets. The availability of insurance may decrease, and the insurance that the Registrants are able to obtain may have higher deductibles, higher premiums, and more restrictive policy terms. Further, the insurance policies may not cover all of the potential exposures or the actual amount of loss incurred. The use of derivative contracts by Southern Company and its subsidiaries in the normal course of business could result in financial losses that negatively impact the net income of the Registrants or in reported net income volatility. Southern Company and its subsidiaries use derivative instruments, such as swaps, options, futures, and forwards, to manage their commodity and interest rate exposures and, to a lesser extent, manage foreign currency exchange rate exposure and engage in limited trading activities. The Registrants could recognize financial losses as a result of volatility in the market values of these contracts or if a counterparty fails to perform. These risks are managed through risk management policies, limits, and procedures, which might not work as planned and cannot entirely eliminate the risks associated with these activities. In addition, derivative contracts entered into for hedging purposes might not offset the underlying exposure being hedged as expected, resulting in financial losses. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management's judgment or use of estimates. The factors used in the valuation of these instruments become more difficult to predict and the calculations become less reliable further into the future. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts. See Notes 13 and 14 to the financial statements in Item 8 herein for additional information. Future impairments of goodwill or long-lived assets could have a material adverse effect on the Registrants' results of operations. Goodwill is not amortized, but is evaluated for impairment at least annually or more frequently if impairment indicators are present that would more likely than not reduce the fair value of a reporting unit below its carrying amount and long-lived assets are tested for impairment whenever events or circumstances indicate that an asset group's carrying amount may not be recoverable. At December 31, 2022, goodwill was $5.2 billion and $5.0 billion for Southern Company and Southern Company Gas, respectively. In addition, Southern Company and its subsidiaries have long-lived assets recorded on their balance sheets. To the extent the carrying amount of goodwill or long-lived assets become impaired, the affected Registrant may be required to incur impairment charges that could have a material impact on their results of operations. See Notes 1, 7, 9, and 15 to the financial statements in Item 8 herein for information regarding certain impairment charges at Southern Company and Southern Company Gas.

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Item 1.Business.##TABLE_END The York Water Company (the Company) is the oldest investor-owned water utility in the United States and is duly organized under the laws of the Commonwealth of Pennsylvania. The Company has operated continuously since 1816. The primary business of the Company is to impound, purify to meet or exceed safe drinking water standards and distribute water. The Company also owns and operates three wastewater collection systems and eight wastewater collection and treatment systems. The Company operates within its franchised water and wastewater territory, which covers portions of 54 municipalities within three counties in south-central Pennsylvania. The Company is regulated by the Pennsylvania Public Utility Commission, or PPUC, for both water and wastewater in the areas of billing, payment procedures, dispute processing, terminations, service territory, debt and equity financing and rate setting. The Company must obtain PPUC approval before changing any practices associated with the aforementioned areas.Water service is supplied through the Companys own distribution system. The Company obtains the bulk of its water supply for its primary system for York and Adams Counties from both the South Branch and East Branch of the Codorus Creek, which together have an average daily flow of 73.0 million gallons from a combined watershed area of approximately 117 square miles. The Company has two reservoirs on this primary system, Lake Williams and Lake Redman, which together hold up to approximately 2.2 billion gallons of water. The Company supplements these reservoirs with a 15-mile pipeline from the Susquehanna River to Lake Redman which provides access to an additional supply of 12.0 million gallons of untreated water per day. The Company obtains its water supply for its system for Franklin County from the Roxbury Dam on the Conodoguinet Creek, which has an average daily flow of approximately 26.0 million gallons from a watershed area of approximately 33 square miles. The Company has a reservoir on this system which holds up to approximately 330 million gallons of water. The Company also owns eleven wells which are capable of providing a safe yield of approximately 637,000 gallons per day to supply water to the customers of its groundwater satellite systems in York and Adams Counties. As of December 31, 2022, the Companys average daily availability was 40.8 million gallons, and average daily consumption was approximately 21.1 million gallons. The Companys service territory had an estimated population of 208,000 as of December 31, 2022. Industry within the Companys service territory is diversified, manufacturing such items as fixtures and furniture, electrical machinery, food products, paper, ordnance units, textile products, air conditioning systems, laundry detergent, barbells, and motorcycles.The Companys water business is somewhat dependent on weather conditions, particularly the amount and timing of precipitation. Revenues are particularly vulnerable to weather conditions in the summer months. Prolonged periods of hot and dry weather generally cause increased water usage for watering lawns, washing cars, and keeping golf courses and sports fields irrigated. Conversely, prolonged periods of dry weather could lead to drought restrictions from governmental authorities. Despite the Companys adequate water supply, customers may be required to cut back water usage under such drought restrictions which would negatively impact revenues. The Company has addressed some of this vulnerability by instituting minimum customer charges which are intended to cover fixed costs of operations under all likely weather conditions.The Companys business does not require large amounts of working capital and is not dependent on any single customer or a very few customers for a material portion of its business. Increases in revenues are generally dependent on the Companys ability to obtain rate increases from the PPUC in a timely manner and in adequate amounts and to increase volumes of water sold through increased consumption and increases in the number of customers served. The Company continuously looks for water and wastewater acquisition and expansion opportunities both within and outside its current service territory as well as additional opportunities to enter into bulk water contracts with municipalities and other entities to supply water.The Company has agreements with several municipalities to provide billing and collection services. The Company also has a service line protection program on a targeted basis in order to further diversify its business. Under this optional program, customers pay a fixed monthly fee, and the Company will repair or replace damaged customer service lines, as needed, subject to an annual maximum dollar amount. The Company continues to review and consider opportunities to expand both initiatives.Page 4 CompetitionAs a regulated utility, the Company operates within an exclusive franchised territory that is substantially free from direct competition with other public utilities, municipalities, and other entities. Although the Company has been granted an exclusive franchise for each of its existing community water and wastewater systems, the ability of the Company to expand or acquire new service territories may be affected by currently unknown competitors obtaining franchises to surrounding systems by application or acquisition. These competitors may include other investor-owned utilities, nearby municipally-owned utilities and sometimes competition from strategic or financial purchasers seeking to enter or expand in the water and wastewater industry. The addition of new service territory and the acquisition of other utilities are generally subject to review and approval by the PPUC.Water and Wastewater Quality and Environmental RegulationsProvisions of water and wastewater service are subject to regulation under the federal Safe Drinking Water Act, the Clean Water Act and related state laws, and under federal and state regulations issued under these laws. In addition, the Company is subject to federal and state laws and other regulations relating to solid waste disposal, dam safety and other aspects of its operations.The federal Safe Drinking Water Act establishes criteria and procedures for the U.S. Environmental Protection Agency, or EPA, to develop national quality standards. Regulations issued under the Act, and its amendments, set standards on the amount of certain contaminants allowable in drinking water. Current requirements are not expected to have a material impact on the Companys operations or financial condition as it already meets or exceeds standards. In the future, the Company may be required to change its method of treating drinking water and may incur additional capital investments if new regulations become effective.Under the requirements of the Pennsylvania Safe Drinking Water Act, or SDWA, the Pennsylvania Department of Environmental Protection, or DEP, regulates the quality of the finished water supplied to customers. The DEP requires the Company to submit monthly reports showing the results of daily bacteriological and other chemical and physical analyses. As part of this requirement, the Company conducts over 70,000 laboratory tests annually. Management believes that the Company complies with the standards established by the agency under the SDWA. The DEP assists the Company by regulating discharges into the Companys watershed area to prevent and eliminate pollution.The federal Groundwater Rule establishes protections against microbial pathogens in community water supplies. This rule requires additional testing of water from well sources, and under certain circumstances requires demonstration and maintenance of effective disinfection. The Company holds public water supply permits issued by the DEP, which establishes the groundwater source operating conditions for its wells, including demonstrated 4-log treatment of viruses. All of the groundwater satellite systems operated by the Company are in compliance with the federal Groundwater Rule.The Clean Water Act regulates discharges from water and wastewater treatment facilities into lakes, rivers, streams, and groundwater. The Company complies with this Act by obtaining and maintaining all required permits and approvals for discharges from its water and wastewater facilities and by satisfying all conditions and regulatory requirements associated with the permits.The DEP monitors the quality of wastewater discharge effluent under the provisions of the National Pollutant Discharge Elimination System, or NPDES. The Company submits monthly reports to the DEP showing the results of its daily effluent monitoring and removal of sludge and biosolids. The Company is not aware of any significant environmental remediation costs necessary from the handling and disposal of waste material from its wastewater operations.Page 5 Lead and copper may enter drinking water primarily through plumbing materials. The Company is required to comply with the Lead and Copper Rule established by the EPA and administered by the DEP. The Company must monitor drinking water at customer taps for compliance with this rule. If lead concentrations exceed an action level, the Company must undertake a number of additional actions to control corrosion, inform the public about steps they should take to protect their health and may be required to replace lead service lines under its control. The Company is currently in compliance with standards under the Lead and Copper Rule.The DEP and the Susquehanna River Basin Commission, or SRBC, regulate the amount of water withdrawn from streams in the watershed to assure that sufficient quantities are available to meet the needs of the Company and other regulated users. Through its Division of Dam Safety, the DEP regulates the operation and maintenance of the Companys impounding dams. The Company routinely inspects its dams and prepares annual reports of their condition as required by DEP regulations. The DEP reviews these reports and inspects the Companys dams. The DEP most recently inspected some of the Companys dams in 2022.Since 1980, the DEP has required any new dam to have a spillway that is capable of passing the design flood without overtopping the dam. The design flood is either the Probable Maximum Flood, or PMF, or some fraction of it, depending on the size and location of the dam. PMF is very conservative and is calculated using the most severe combination of meteorological and hydrologic conditions reasonably possible in the watershed area of a dam.The Company engaged a professional engineer to analyze the spillway capacities at the Lake Williams and Lake Redman dams and validate the DEPs recommended flood design for the dams. Management presented the results of the study to the DEP in December 2004, and DEP then requested that the Company submit a proposed schedule for the actions to address the spillway capacities. Thereafter, the Company retained an engineering firm to prepare preliminary designs for increasing the spillway capacities to pass the PMF through armoring the dams with roller compacted concrete. Management met with the DEP on a regular basis to review the preliminary design and discuss scheduling, permitting, and construction requirements including their concern regarding the stability of the Lake Williams spillway in light of current design standards. The Company completed the final design and the permitting process to armor and replace the spillway of the Lake Williams dam and began construction in 2022 at a total cost of approximately $39 million. The Lake Redman dam will be reviewed following the completion of the work on the Lake Williams dam.Capital expenditures and operating costs required as a result of water quality standards and environmental requirements have been traditionally recognized by state public utility commissions as appropriate for inclusion in establishing rates. The capital expenditures currently required as a result of water quality standards and environmental requirements have been budgeted in the Companys capital program and represent less than 15% of its expected total capital expenditures over the next five years. The Company is currently in compliance with wastewater environmental standards and does not anticipate any major capital expenditures for its current wastewater business.Growth(All dollar amounts are stated in thousands of dollars)The Company continues to grow its number of customers and distribution facilities.The growth in the number of customers is due primarily to the acquisition of water and wastewater systems and organic growth. During the year ended December 31, 2022, the Company increased its number of customers from 73,144 to 76,731. See Managements Discussion and Analysis Acquisitions and Growth for a discussion of the Companys recent acquisitions.The Company continues to grow its water distribution and wastewater collection systems to provide reliable service to its expanding franchised service territory and the increasing population within that territory. During the year ended December 31, 2022, the Company installed an additional 97,800 feet of water distribution mains and acquired an additional 235,200 feet of water distribution mains resulting in 1,065 miles of water mains as of December 31, 2022. During the year ended December 31, 2022, the Company acquired an additional 114,100 feet of wastewater collection mains resulting in 94 miles of wastewater mains as of December 31, 2022.Page 6 The Companys growth in revenues is primarily a result of customer growth and increases in water and wastewater rates. During the year ended December 31, 2022, the Company recognized revenue of $60,061, an increase of $4,942, or 9.0%, as compared to $55,119 during the year ended December 31, 2021. In 2022, operating revenue was derived from the following sources and in the following percentages: residential, 65%; commercial and industrial, 27%; and other, 8%, which is primarily from the provision for fire service but includes other water and wastewater service-related income. See Managements Discussion and Analysis Rate Matters for a discussion of the Companys rate case management.Information about Our Executive OfficersThe Company presently has 116 employees, all of which are full time employees including the officers detailed in the information set forth under the caption Executive Officers of the Company of the 2023 Proxy Statement incorporated herein by reference.Available InformationThe Company makes available free of charge, on or through its website (www.yorkwater.com), its annual report on Form 10-K, its quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after the Company electronically files such material with, or furnishes it to, the SEC. The SEC also maintains a website at www.sec.gov that contains reports, proxy statements, and other information about SEC registrants, including the Company.Shareholders may request, without charge, copies of the Companys financial reports. Such requests, as well as other investor relations inquiries, should be addressed to:##TABLE_START Molly E.

Ticker: YORW, Sector: Utilities, Filed At: 2023-03-07T11:39:13-05:00

HouckThe York Water Company(717) 718-2942Investor Relations 130 East Market Street(800) 750-5561Communications AdministratorYork, PA 17401mollyh@yorkwater.com##TABLE_END ##TABLE_START Item 1A.Risk Factors.##TABLE_END Not applicable.##TABLE_START

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ITEMS 1. AND 2. BUSINESS AND PROPERTIES CORPORATE OVERVIEW UGI Corporation is a holding company that, through subsidiaries and affiliates, distributes, stores, transports and markets energy products and related services. In the U.S., we own and operate (1) a retail propane marketing and distribution business, (2) natural gas and electric distribution utilities, and (3) energy marketing (including RNG), midstream infrastructure, storage, natural gas gathering and processing, natural gas production, electricity generation and energy services businesses. In Europe, we market and distribute propane and other LPG, and market other energy products and services. Our subsidiaries and affiliates operate principally in the following four business segments: AmeriGas Propane UGI International Midstream Marketing Utilities The AmeriGas Propane segment consists of the propane distribution business of AmeriGas Partners, an indirect wholly owned subsidiary of UGI. The Partnership conducts its domestic propane distribution business through its principal operating subsidiary, AmeriGas OLP, and is the nations largest retail propane distributor based on the volume of propane gallons distributed annually. The general partner of AmeriGas Partners is our wholly owned subsidiary, AmeriGas Propane, Inc. The UGI International segment consists of LPG distribution businesses conducted by our subsidiaries and affiliates in Austria, Belgium, the Czech Republic, Denmark, Finland, France, Hungary, Italy, Luxembourg, the Netherlands, Norway, Poland, Romania, Slovakia, Sweden, Switzerland and the United Kingdom. Based on reported market volumes for 2022, which is the most recent information available, UGI International believes that it is the largest distributor of LPG in France, Austria, Belgium, Denmark and Luxembourg and one of the largest distributors of LPG in Norway, Poland, the Czech Republic, Slovakia, the Netherlands, Sweden and Switzerland. During Fiscal 2023, we made significant progress on our strategic decision to exit the energy marketing business at UGI International. In Fiscal 2023, we divested of our energy marketing business in the United Kingdom and Belgium. On October 1, 2023, we divested substantially all of our energy marketing business in France. We also continue to make significant progress on the wind-down of our energy marketing business in the Netherlands. See Note 5 for additional information regarding the UGI International energy marketing businesses. The Midstream Marketing segment consists of energy-related businesses conducted by our indirect, wholly owned subsidiary, Energy Services. These businesses (i) conduct energy marketing, including RNG, in the Mid-Atlantic region of the United States and California, (ii) own and operate natural gas liquefaction, storage and vaporization facilities and propane-air mixing assets, (iii) manage natural gas pipeline and storage contracts, (iv) develop, own and operate pipelines, gathering infrastructure and gas storage facilities in the Marcellus and Utica Shale regions of Pennsylvania, eastern Ohio, and the panhandle of West Virginia, (v) own electricity generation facilities, and (vi) develop, own and operate RNG production facilities. Energy Services and its subsidiaries storage, LNG and portions of its midstream transmission operations are subject to regulation by the FERC. The Utilities segment consists of the regulated natural gas (PA Gas Utility) and electric (Electric Utility) distribution businesses of our wholly owned subsidiary, UGI Utilities, and the regulated natural gas distribution business of our indirect, wholly owned subsidiary, Mountaineer. PA Gas Utility serves customers in eastern and central Pennsylvania and in portions of one Maryland county, and Mountaineer serves customers in West Virginia. Electric Utility serves customers in portions of Luzerne and Wyoming counties in northeastern Pennsylvania. PA Gas Utility is subject to regulation by the PAPUC and FERC and, with respect to its customers in Maryland, the MDPSC. Mountaineer is subject to regulation by the WVPSC and FERC. Electric Utility is subject to regulation by the PAPUC and FERC. Business Strategy Our business strategy is to grow the Company by focusing on our core competencies of distributing, storing, transporting and marketing energy products and services. We utilize our core competencies from our existing diversified businesses and our international experience, extensive asset base and access to customers to accelerate both organic growth and growth through acquisitions in our existing businesses, as well as in related and complementary businesses. In August 2023, the Company announced the commencement of a strategic review with a focus on our LPG businesses to unlock and maximize shareholder value. See Item 7. Managements Discussion and Analysis of Financial Condition and Results of Operations for additional information. We continue to focus on advancing our strategy of: (1)

providing reliable earnings growth; (2) rebalancing our portfolio, with an emphasis on natural gas and renewable energy solutions; and (3) investing in renewable energy solutions. The following discussion highlights some of our key accomplishments in these areas during Fiscal 2023. Reliable Earnings Growth We are committed to consistently growing our earnings and plan to continue this growth through robust investments in our regulated utilities businesses, generating significant fee-based income in our Midstream and Marketing operations, optimizing our cost structure and effectively managing our global LPG businesses, which generate significant free cash flow. We strive to be the preferred provider in all markets we serve and remain focused on making continuous improvements and focusing on growth across our businesses. At our Utilities segment, we continue to deliver attractive earnings growth through capital investments and customer additions, while taking actions to reduce earnings volatility. In Fiscal 2023, PA Gas Utility connected more than 1,460 new commercial and industrial customers and added more than 11,100 residential heating customers. Beginning on November 1, 2022, PA Gas Utility was authorized to implement a weather normalization adjustment rider as a five-year pilot program which we expect to result in reduced earnings volatility and stabilize our customers distribution charges. In September 2023, our Electric Utility received PAPUC approval for an $8.5 million annual base distribution rate increase beginning in October 2023. On October 6, 2023, Mountaineer filed a joint stipulation and agreement for settlement of the base rate case proceeding that Mountaineer had initiated in March of 2023 with the WVPSC. The settlement is subject to approval by the WVPSC and is expected to result in a net revenue increase of approximately $13.9 million and an overall increase in total revenues of 4.16% for Mountaineer. See Note 9 to Consolidated Financial Statements for additional information. Our Midstream and Marketing business continues to provide stable earnings, which is underpinned by fee-based contracts from customers. This fee-based income is derived from fixed-fee peaking, storage and gathering, and fixed rate, variable volume gathering and marketing transactions. In Fiscal 2023, over 85% of Midstream and Marketings total margin was fee-based. In addition, Midstream and Marketing continued expanding in the renewable energy space, which we believe will contribute to our future earnings growth. For more information on these transactions, see Investment in Renewable Energy below. During Fiscal 2023, we made technology and other investments to promote the safety of our employees and the communities we serve. For example, we continued (i) installing cameras in our delivery and service vehicles to facilitate in-cab coaching capabilities, among other functionality, and (ii) installing fall protection towers on rail terminals that are designed to prevent employees from falling during the process of offloading propane into bulk storage. During Fiscal 2023, we made significant progress on our strategic decision to exit the energy marketing business at UGI International. We divested of our energy marketing businesses in the United Kingdom and Belgium during Fiscal 2023 and divested substantially all of our energy marketing business in France on October 1, 2023. In addition, we continue to make progress on the wind-down of our energy marketing business in the Netherlands.

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Rebalancing Our Portfolio We are committed to rebalancing our portfolio through both organic growth and investment in natural gas and renewable energy solutions. In Fiscal 2023, we executed our rebalancing strategy by prioritizing our capital investment in the natural gas businesses. At the Utilities, we continued to execute our infrastructure replacement and system betterment program, with record capital expenditures in Fiscal 2023 and additional expenditures expected in the coming years. Our PA Gas Utility remains on schedule to achieve its goal of replacing the cast iron portions of its gas mains by March 2027 and the bare steel portion of its gas mains by September 2041. We believe that the replacement of aging infrastructure results in increased contributions to rate base growth and also reduces emissions while improving operational efficiency and distribution system integrity. Investment in Renewable Energy We are pursuing investments in several renewable energy areas, including RNG, bio-LPG and renewable dimethyl ether. Our natural gas businesses are exploring RNG opportunities involving both distribution and RNG feedstock infrastructure, and our LPG businesses are developing bio-LPG sources to augment our existing bio-LPG source in Sweden. We believe that UGI is well-positioned to develop investment opportunities in these emerging markets due to our competencies in project development, project execution, gas transportation and storage, and energy marketing. We expect to utilize our existing natural gas and LPG distribution infrastructure to deliver RNG and bio-LPG to the customers we serve. In most cases, these renewable solutions can be delivered to our customers with no additional local infrastructure, incremental investments by our customers, or community disruption related to infrastructure buildout. In Fiscal 2023, we completed the following transactions: In November 2022, Energy Services announced a project that will modify an existing anaerobic biogas facility to generate RNG. The project is expected to be completed in the second half of 2024 and, once completed, is expected to produce approximately 35 million cubic feet of RNG annually. In January 2023, Energy Services announced that it entered into an agreement to invest $150 million in two RNG projects currently under development in South Dakota. One project is expected to generate approximately 300 million cubic feet of RNG annually once completed in calendar year 2024 and the other project is expected to generate approximately 225 million cubic feet of RNG annually once completed in calendar year 2024. In February 2023, Energy Services entered into a joint venture to develop an RNG project at the Commonwealth Environmental Systems landfill in Pennsylvania. Once complete, the project is expected to have the capacity to produce approximately 5,000 MMBtu per day of pipeline-quality RNG. These projects provide a range of benefits, including reducing our carbon footprint while also addressing increased customer demand for low carbon energy sources. Environmental Strategy We believe that corporate sustainability is critical to our overall business success and we are committed to growing the Company in an environmentally responsible way. UGIs environmental strategy is focused on three main areas: reducing our emissions; reducing our customers emissions affordably, reliably, and responsibly; and investing in renewable solutions. To support our strategy, we have made the following environmental commitments discussed below while also committing to continue to grow our earnings per share and dividends. Scope 1 Emissions Reduction Commitment Reduce Scope 1 GHG emissions by 55% by 2025 (using Fiscal 2020 as a baseline). Our Scope 1 emissions reduction target does not include emissions from the Mountaineer Acquisition, which closed in September 2021. The target also excluded the Stonehenge Acquisition and only accounts for our ownership interest in Pennant at the time we set the target. The emissions from the Pine Run acquisition were included in the baseline 2020 number as this investment contributed to our goal. The 2020 base number also takes a five year emissions average from the Hunlock generation facility to account for year-over-year differences in run time. Methane Emissions Reduction Commitment 92% reduction by 2030, and 95% reduction by 2040. Pipeline Replacement and Betterment Commitment Replace all cast iron pipelines by 2027 and all bare steel by 2041. Our pipeline replacement and betterment activities better enable us to achieve our emissions reductions goals. We report our progress on the environmental goals and commitments annually in our Sustainability Reports, including our Scope 1, 2 and 3 emissions, air quality impact, and water management efforts. Our Scope 3 emissions stem primarily from the extraction (upstream) and combustion (downstream) of the molecules we distribute, and from our supply chain. Our Sustainability Reports may be accessed on our website under ESG - Resources - Sustainability Reports. Information published in our Sustainability Reports is not incorporated by reference in this Report. In formulating our environmental strategy, our management and Board of Directors consider certain risks and uncertainties that may materially impact our financial condition and results of operations. For more information on these risks and uncertainties, see Risk Factors - The potential effects of climate change may affect our business, operations, supply chain and customers, which could adversely impact our financial condition and results of operations. Corporate Information UGI was incorporated in Pennsylvania in 1991. The Company is not subject to regulation by the PAPUC but, following completion of the Mountaineer Acquisition, is a regulated holding company under PUHCA 2005. PUHCA 2005 and the implementing regulations of FERC give FERC access to certain holding company books and records and impose certain accounting, record-keeping, and reporting requirements on holding companies. PUHCA 2005 also provides state utility regulatory commissions with access to holding company books and records in certain circumstances. Our executive offices are located at 500 North Gulph Road, King of Prussia, Pennsylvania 19406, and our telephone number is (610) 337-1000. In this Report, the terms Company and UGI, as well as the terms our, we, us, and its are sometimes used as abbreviated references to UGI Corporation or, collectively, UGI Corporation and its consolidated subsidiaries. For further information on the meaning of certain terms used in this Report, see Glossary of Terms and Abbreviations. The Companys corporate website can be found at www.ugicorp.com. Information on our website, including the information published in our Sustainability Reports, is not incorporated by reference in this Report. The Company makes available free of charge at this website (under the Investors - Financial Reports -

SEC Filings and Proxies caption) copies of its reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, including its Annual Reports on Form 10-K, its Quarterly Reports on Form 10-Q, and its Current Reports on Form 8-K. The Companys Principles of Corporate Governance, Code of Business Conduct and Ethics, and Supplier Code of Business Conduct and Ethics are available on the Companys website under the caption Company - Leadership and Governance - Governance Documents. The charters of the Audit, Corporate Governance, Compensation and Management Development, and Safety, Environmental and Regulatory Compliance Committees of the Board of Directors are available on the Companys website under the caption Company - Leadership and Governance - Committees Charters. All of these documents are also available free of charge by writing to Director, Investor Relations, UGI Corporation, P.O. Box 858, Valley Forge, PA 19482. AMERIGAS PROPANE Products, Services and Marketing Our domestic propane distribution business is conducted through AmeriGas Propane. AmeriGas Propane serves nearly 1.2 million customers in all 50 states from approximately 1,380 propane distribution locations. Typically, propane distribution locations are in suburban and rural areas where natural gas is not readily available. Our local offices generally consist of operations facilities and propane storage. As part of its overall transportation and distribution infrastructure, AmeriGas Propane operates as an interstate carrier in all states throughout the continental U.S. AmeriGas Propane sells propane primarily to residential, commercial/industrial, motor fuel, agricultural and wholesale customers. AmeriGas Propane distributed approximately 940 million gallons of propane in Fiscal 2023. Approximately 88% of AmeriGas Propanes Fiscal 2023 sales (based on gallons sold) was to retail accounts and approximately 12% was to wholesale accounts. Sales to residential customers in Fiscal 2023 represented approximately 30% of retail gallons sold; commercial/industrial customers 41%; motor fuel customers 21%; and agricultural customers 3%. Transport gallons, which are large-scale deliveries to retail customers other than residential, accounted for approximately 5% of Fiscal 2023 retail gallons. With the exception of one customer representing 5.1% of AmeriGas Propanes consolidated revenues, no other single customer represents more than 5% of AmeriGas Propanes consolidated revenues. The ACE program continued to be an important element of AmeriGas Propanes business in Fiscal 2023. At September 30, 2023, ACE cylinders were available at over 48,000 retail locations throughout the U.S. Sales of our ACE cylinders to retailers are included in commercial/industrial sales. The ACE program enables consumers to purchase or exchange propane cylinders at various retail locations such as home centers, gas stations, mass merchandisers and grocery and convenience stores. In addition, our Cynch propane home delivery service was available in 24 cities as of September 30, 2023. We also supply retailers with large propane tanks to enable them to replenish customers propane cylinders directly at the retailers locations. Residential and commercial customers use propane primarily for home heating, water heating and cooking purposes. Commercial users include hotels, restaurants, churches, warehouses and retail stores. Industrial customers use propane to fire furnaces, as a cutting gas and in other process applications. Other industrial customers are large-scale heating accounts and local gas utility customers that use propane as a supplemental fuel to meet peak load deliverability requirements. As a motor fuel, propane is burned in internal combustion engines that power school buses and other over-the-road vehicles, forklifts and stationary engines. Agricultural uses include tobacco curing, chicken brooding, crop drying and orchard heating. In its wholesale operations, AmeriGas Propane principally sells propane to large industrial end-users and other propane distributors. Retail deliveries of propane are usually made to customers by means of bobtail and rack trucks. Propane is pumped from the bobtail truck, which generally holds 2,400 to 3,000 gallons of propane, into a stationary storage tank on the customers premises. AmeriGas Propane owns most of these storage tanks and leases them to its customers. The capacity of these tanks ranges from approximately 120 gallons to approximately 1,200 gallons. AmeriGas Propane also delivers propane in portable cylinders, including ACE and motor fuel cylinders. Some of these deliveries are made to the customers location where cylinders are either picked up or replenished in place. During Fiscal 2023, we made technology and other investments to promote the safety of our employees and the communities we serve. For example, we continued (i) installing cameras in our delivery and service vehicles to facilitate in-cab coaching capabilities, among other functionality, and (ii) installing fall protection towers on rail terminals that are designed to prevent employees from falling during the process of offloading propane into bulk storage. Propane Supply and Storage The U.S. propane market has approximately 190 domestic and international sources of supply, including the spot market. Supplies of propane from AmeriGas Propanes sources historically have been readily available. In recent years, certain geographies experienced varying levels of reduced propane availability as a result of transportation issues within the supply chain. In response to these supply and transportation challenges, AmeriGas Propane utilized a combination of increased regional storage as well as rail and transport supply from different origins to offset localized supply/demand imbalances. In addition to these factors, the availability and pricing of propane supply has historically been dependent upon, among other things, the severity of winter weather, the price and availability of competing fuels such as natural gas and crude oil, and the amount and availability of exported supply and, to a much lesser extent, imported supply. For more information on risks relating to our supply chain, see Risk Factors - Risks Relating to Our Supply Chain and Our Ability to Obtain Adequate Quantities of LPG. During Fiscal 2023, approximately 97% of AmeriGas Propanes propane supply was purchased under supply agreements with terms of one to three years. Although no assurance can be given that supplies of propane will be readily available in the future, management currently expects to be able to secure adequate supplies during Fiscal 2024. If supply from major sources were interrupted, however, the cost of procuring replacement supplies and transporting those supplies from alternative locations might be materially higher and, at least on a short-term basis, margins could be adversely affected. In Fiscal 2023, AmeriGas Propane derived approximately 14% of its propane supply from Enterprise Products Operating LLC and approximately 11% of its propane supply from Targa Liquids Marketing and Trade LLC. No other single supplier provided more than 10% of AmeriGas Propanes total propane supply in Fiscal 2023. In certain geographic areas, however, a single supplier provides more than 50% of AmeriGas Propanes requirements. Disruptions in supply in these areas could also have an adverse impact on AmeriGas Propanes margins. AmeriGas Propanes supply contracts typically provide for pricing based upon (i) index formulas using the current prices established at a major storage point such as Mont Belvieu, Texas, or Conway, Kansas, or (ii) posted prices at the time of delivery. In addition, some agreements provide maximum and minimum seasonal purchase volume guidelines. The percentage of contract purchases, and the amount of supply contracted for at fixed prices, will vary from year to year. AmeriGas Propane uses a number of interstate pipelines, as well as railroad tank cars, delivery trucks and barges, to transport propane from suppliers to storage and distribution facilities. AmeriGas Propane stores propane at various storage facilities and terminals located in strategic areas across the U.S. Because AmeriGas Propanes profitability is sensitive to changes in wholesale propane costs, AmeriGas Propane generally seeks to pass on increases in the cost of propane to customers. There is no assurance, however, that AmeriGas Propane will always be able to pass on product cost increases fully, or keep pace with such increases, particularly when product costs rise rapidly. Product cost increases can be triggered by periods of severe cold weather, supply interruptions, increases in the prices of base commodities, such as crude oil and natural gas, or other unforeseen events. AmeriGas Propane has supply acquisition and product cost risk management practices to reduce the effect of volatility on selling prices. These practices currently include the use of summer storage, forward purchases and derivative commodity instruments, such as propane price swaps. See Managements Discussion and Analysis of Financial Condition and Results of Operations - Market Risk Disclosures. The following graph shows the average prices of propane on the propane spot market during the last five fiscal years at Mont Belvieu, Texas, and Conway, Kansas, both major storage areas. Average Propane Spot Market Prices General Industry Information Propane is separated from crude oil during the refining process and also extracted from natural gas or oil wellhead gas at processing plants. Propane is normally transported and stored in a liquid state under moderate pressure or refrigeration for economy and ease of handling in shipping and distribution. When the pressure is released or the temperature is increased, it is usable as a flammable gas. Propane is colorless and odorless; an odorant is added to allow for its detection. Propane is considered a clean alternative fuel under the Clean Air Act Amendments of 1990. Competition Propane competes with other sources of energy, some of which are less costly for equivalent energy value. Propane distributors compete for customers with suppliers of electricity, fuel oil and natural gas, principally on the basis of price, service, availability and portability. Electricity is generally more expensive than propane on a Btu equivalent basis, but the convenience and efficiency of electricity make it an attractive energy source for consumers and developers of new homes. Fuel oil, which is also a major competitor of propane, is a less environmentally attractive energy source. Furnaces and appliances that burn propane will not operate on fuel oil, and vice versa, and, therefore, a conversion from one fuel to the other requires the installation of new equipment. Propane serves as an alternative to natural gas in rural and suburban areas where natural gas is unavailable or portability of product is required. Natural gas is generally a significantly less expensive source of energy than propane, although in areas where natural gas is available, propane is used for certain industrial and commercial applications and as a standby fuel during interruptions in natural gas service. The gradual expansion of the nations natural gas distribution systems has resulted in the availability of natural gas in some areas that previously depended upon propane. However, natural gas pipelines are not present in many areas of the country where propane is sold for heating and cooking purposes. For motor fuel customers, propane competes with gasoline, diesel fuel, electric batteries, fuel cells and, in certain applications, LNG and compressed natural gas. Wholesale propane distribution is a highly competitive, low margin business. Propane sales to other retail distributors and large-volume, direct-shipment industrial end-users are price sensitive and frequently involve a competitive bidding process. Retail propane industry volumes have been flat for several years and no or modest growth in total demand is foreseen in the next several years. Therefore, AmeriGas Propanes ability to grow within the industry is dependent on the success of its sales and marketing programs designed to attract and retain customers, the success of business transformation initiatives, its ability to achieve internal growth, which includes the continuation of ACE, Cynch and National Accounts (through which multi-location propane users enter into a single AmeriGas Propane supply agreement rather than agreements with multiple suppliers), and its ability to acquire other retail distributors. The failure of AmeriGas Propane to retain and grow its customer base would have an adverse effect on its long-term results. The domestic propane retail distribution business is highly competitive. AmeriGas Propane competes in this business with other large propane marketers, including other full-service marketers, and thousands of small independent operators. Some farm cooperatives, rural electric cooperatives and fuel oil distributors include propane distribution in their businesses and AmeriGas Propane competes with them as well. The ability to compete effectively depends on providing high quality customer service, maintaining competitive retail prices and controlling operating expenses. AmeriGas Propane also offers customers various payment and service options, including guaranteed price programs, fixed price arrangements and pricing arrangements based on published propane prices at specified terminals. In Fiscal 2023, AmeriGas Propanes retail propane sales totaled approximately 820 million gallons. Based on the most recent annual survey by the Propane Education Research Council, 2022 domestic retail propane sales (annual sales for other than chemical uses) in the U.S. totaled approximately 9.8 billion gallons. Based on LP-GAS magazine rankings, 2022 sales volume of the ten largest propane distribution companies (including AmeriGas Propane) represented approximately 32%

of domestic retail propane sales. Properties As of September 30, 2023, AmeriGas Propane owned approximately 87% of its nearly 525 local offices throughout the country. The transportation of propane requires specialized equipment. The trucks and railroad tank cars utilized for this purpose carry specialized steel tanks that maintain the propane in a liquefied state. As of September 30, 2023, the Partnership operated a transportation fleet with the following assets: ##TABLE_START Approximate Quantity Equipment Type % Owned % Leased 850 Trailers 66% 34% 320 Tractors 1% 99% 650 Railroad tank cars 0% 100% 2,460 Bobtail trucks 4% 96% 285 Rack trucks 9% 91% 2,910 Service and delivery trucks 11% 89% ##TABLE_ENDOther assets owned at September 30, 2023 included approximately 909,000 stationary storage tanks with typical capacities of more than 120 gallons, approximately 4.7 million portable propane cylinders with typical capacities of 1 to 120 gallons, 21 terminals and 11 transflow units. Trade Names, Trade and Service Marks AmeriGas Propane markets propane and other services principally under the AmeriGas , Americas Propane Company , and Cynch trade names and related service marks. AmeriGas Propane owns, directly or indirectly, all the right, title and interest in the AmeriGas name and related trade and service marks. AmeriGas Polska Sp. z.o.o. has an exclusive, royalty-free license from AmeriGas Propane to use the AmeriGas name and related service marks in Poland and Germany and with respect thereto on the Internet. The term of the license is in perpetuity. Seasonality Because many customers use propane for heating purposes, AmeriGas Propanes retail sales volume is seasonal. During Fiscal 2023, approximately 63% of the Partnerships retail sales volume occurred, and substantially all of AmeriGas Propanes operating income was earned, during the peak heating season from October through March. As a result of this seasonality, revenues are typically higher in AmeriGas Propanes first and second fiscal quarters (October 1 through March 31). Cash receipts are generally greatest during the second and third fiscal quarters when customers pay for propane purchased during the winter heating season. For more information on the risks associated with the seasonality of our business, see Risk Factors - Our business is seasonal and decreases in the demand for our energy products and services because of warmer-than-normal heating season weather or unfavorable weather conditions may adversely affect our results of operations. Sales volume for AmeriGas Propane traditionally fluctuates from year-to-year in response to variations in weather, prices, competition, customer mix and other factors, such as conservation efforts and general economic conditions. For information on national weather statistics, see Managements Discussion and Analysis of Financial Condition and Results of Operations. Government Regulation AmeriGas Propane is subject to various federal, state and local environmental, health, data privacy, safety and transportation laws and regulations governing the storage, distribution and transportation of propane and the operation of bulk storage propane terminals. Environmental Generally, applicable environmental laws impose limitations on the discharge of pollutants, establish standards for the handling of solid and hazardous substances, and require the investigation and cleanup of environmental contamination.

These laws include, among others, the Resource Conservation and Recovery Act, CERCLA, the Clean Air Act, the Clean Water Act, the Homeland Security Act of 2002, the Emergency Planning and Community Right-to-Know Act, comparable state statutes and any applicable amendments. The Partnership incurs expenses associated with compliance with its obligations under federal and state environmental laws and regulations, and we believe that the Partnership is in material compliance with its obligations. The Partnership maintains various permits that are necessary to operate its facilities, some of which may be material to its operations. AmeriGas Propane continually monitors its operations with respect to potential environmental issues, including changes in legal requirements. AmeriGas Propane is investigating and remediating contamination at a number of present and former operating sites in the U.S., including sites where its predecessor entities operated MGPs. CERCLA and similar state laws impose joint and several liability on certain classes of persons considered to have contributed to the release or threatened release of a hazardous substance into the environment without regard to fault or the legality of the original conduct. Propane is not a hazardous substance within the meaning of CERCLA. Health and Safety AmeriGas Propane is subject to the requirements of OSHA and comparable state laws that regulate the protection of the health and safety of our workers. These laws require the Partnership, among other things, to maintain information about materials utilized, stored, transported, or sold, in accordance with OSHAs Hazard Communications Standard. Certain portions of this information must be provided to employees, federal and state and local governmental authorities, emergency responders, commercial and industrial customers and local citizens in accordance with the Environmental Protection Agencys Emergency Planning and Community Right-to-Know Act requirements. All states in which AmeriGas Propane operates have adopted fire and life safety codes that regulate the storage, distribution, and use of propane. In some states, these laws are administered by state agencies, and in others they are administered on a municipal level. AmeriGas Propane conducts training programs to help ensure that its operations comply with applicable governmental regulations. With respect to general operations, AmeriGas Propane is subject in all jurisdictions in which it operates to rules and procedures governing the safe handling of propane, including those established by National Fire Protection Association (NFPA) in the Liquefied Petroleum Gas Code (NFPA 58) and National Fuel Gas Code (NFPA 54), the International Code Councils International Fuel Gas Code and International Fire Code, as well as various state and local codes. Management believes that the policies and procedures currently in effect at all of its facilities for the handling, storage, distribution and use of propane are consistent with industry standards and are in compliance, in all material respects, with applicable laws and regulations. With respect to the transportation of propane, AmeriGas Propane is subject to regulations promulgated under federal legislation, including the Federal Motor Carrier Safety Regulations and Pipeline Hazardous Materials Regulations which fall under the enforcement and supervision of the DOT, Pipeline Hazardous Materials Safety

Administration, Federal Railroad Administration, Federal Motor Carrier Safety Administration, and the Federal Aviation Administration. AmeriGas Propane facilities and containers are equally regulated by these agencies regarding security standards as well as the Cybersecurity and Infrastructure Security Agencys Chemical Facility Anti-Terrorism Standards. AmeriGas Propanes programs related to the transportation and security of hazardous materials are regularly inspected and meet all applicable standards and regulations. AmeriGas Propane maintains jurisdictional pipeline systems as defined by the Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards as regulated by the Pipeline Hazardous Materials Safety Administration and multiple State Public Utility Commissions under the authority and authorization of the Pipeline Hazardous Materials Safety Administration. These pipeline safety regulations apply to, among other things, propane gas systems that supplies 10 or more residential customers or two or more commercial customers from a single source and to a propane gas system any portion of which is located in a public place. The DOTs pipeline safety regulations require operators of all gas systems to provide operator qualification standards and training and written instructions for employees and third-party contractors working on covered pipelines and facilities, establish written procedures to minimize the hazards resulting from gas pipeline emergencies, and conduct and keep records of inspections and testing. Operators are subject to the Pipeline Safety Improvement Act of 2002. Management believes that the procedures currently in effect at all of AmeriGas Propanes facilities for the handling, storage, transportation and distribution of propane are consistent with industry standards and are in compliance, in all material respects, with applicable laws and regulations. Climate Change There continues to be increased legislative and regulatory activity related to climate change and the contribution of GHG emissions, most notably carbon dioxide, to global warming. Because propane is considered a clean alternative fuel under the federal Clean Air Act Amendments of 1990, the Partnership believes this provides it with a competitive advantage over other sources of energy, such as fuel oil and coal. At the same time, however, increasing regulations of GHG emissions, especially in the transportation and building sectors, could restrict the use of fossil fuels and could impose significant additional costs on AmeriGas Propane, its suppliers, its vendors and its customers. There has been an increase in state initiatives aimed at regulating GHG emissions, including the California Low Carbon Fuel Standard, the Washington Cap and Invest Program and the New York Climate Leadership and Community Protection Act. Compliance with these types of regulations may increase our operating costs if we are unable to pass on these costs to our customers. Employees The Partnership does not directly employ any persons responsible for managing or operating the Partnership. The General Partner provides these services and is reimbursed for its direct and indirect costs and expenses, including all compensation and benefit costs. At September 30, 2023, the General Partner had approximately 5,160 employees, including more than 100 part-time, seasonal and temporary employees, working on behalf of the Partnership. UGI also performs, and is reimbursed for, certain financial and administrative services on behalf of the Partnership and AmeriGas OLP. UGI INTERNATIONAL UGI International, through its subsidiaries and affiliates, conducts an LPG distribution business in 17 countries throughout Europe (Austria, Belgium, the Czech Republic, Denmark, Finland, France, Hungary, Italy, Luxembourg, the Netherlands, Norway, Poland, Romania, Slovakia, Sweden, Switzerland and the United Kingdom). Based on reported market volumes for 2022, which is the most recent information available, UGI International believes that it is the largest distributor of LPG in France, Austria, Belgium, Denmark and Luxembourg and one of the largest distributors of LPG in Norway, Poland, the Czech Republic, Slovakia, the Netherlands, Sweden and Switzerland. During Fiscal 2023, we made significant progress on our strategic decision to exit the energy marketing business at UGI International. In Fiscal 2023, we divested of our energy marketing business in the United Kingdom and Belgium. On October 1, 2023, we divested substantially all of our energy marketing business in France. We also continue to make significant progress on the wind-down of our energy marketing business in the Netherlands. Products, Services and Marketing LPG Distribution Business During Fiscal 2023, UGI International sold approximately 900 million gallons of LPG throughout Europe. UGI International operates under six distinct LPG brands, and its customer base primarily consists of residential, commercial, industrial, agricultural, wholesale and automobile fuel (autogas) customers that use LPG for space heating, cooking, water heating, motor fuel, leisure activities, crop drying, irrigation, construction, power generation, manufacturing and as an aerosol propellant. For Fiscal 2023, approximately 50% of UGI Internationals LPG volume was sold to commercial and industrial customers, 15% was sold to residential, 9% was sold to agricultural and 26% was sold to wholesale and other customers (including autogas). UGI International supplies LPG to its customers in small, medium and large bulk tanks at their locations. In addition to bulk sales, UGI International sells LPG in cylinders through retail outlets, such as supermarkets, individually owned stores and gas stations and directly to businesses that operate LPG-powered forklifts. Sales of LPG are also made to service stations to fuel vehicles that run on LPG. UGI Internationals Fiscal 2023 LPG sales were attributed to bulk, cylinder, wholesale and autogas. For Fiscal 2023, no single customer represented more than 5% of UGI Internationals revenues. Bulk Approximately 62% of UGI Internationals Fiscal 2023 LPG sales (based on volumes) were attributed to bulk customers. UGI International classifies its bulk customers as small, medium or large bulk, depending upon volume consumed annually at the customer locations. Based on volumes consumed, small bulk customers are primarily residential and small business users, such as restaurants, that use LPG mainly for heating and cooking. Medium bulk customers consist mainly of large residential housing developments, hospitals, hotels, municipalities, medium-sized industrial enterprises and poultry brooders. Large bulk customers include agricultural customers (including crop drying) and companies that use LPG in their industrial processes. UGI International had approximately 492,000 bulk LPG customers and sold 557 million gallons of bulk LPG during Fiscal 2023. Cylinder Approximately 15% of UGI

Internationals Fiscal 2023 LPG sales (based on volumes) were attributed to cylinder customers. UGI International sells LPG in both steel and composite cylinders and typically owns the cylinders in which the LPG is sold. The principal end-users of cylinders are residential customers who use LPG for domestic applications, such as cooking and heating. Non-residential uses include fuel for forklift trucks, road construction and welding. At September 30, 2023, UGI International had more than 20 million cylinders in circulation and sold approximately 137 million gallons of LPG in cylinders during Fiscal 2023. UGI International also delivers LPG to wholesale and retail customers in cylinders, including through the use of vending machines. Wholesale, Autogas and Other Services Approximately 19% of UGI Internationals Fiscal 2023 LPG sales (based on volumes) were to wholesale customers (including small competitors and large industrial customers), and approximately 4% of Fiscal 2023 LPG sales (based on volumes) were to autogas customers. UGI International also provides logistics, storage and other services to third-party LPG distributors. Energy Marketing Business UGI sold its energy marketing business in the United Kingdom, France and Belgium and continues to make progress on the wind-down of its energy marketing business in the Netherlands . For further information, see Managements Discussion and Analysis of Financial Condition and Results of Operations - Executive Overview Recent Developments. LPG Supply, Storage and Transportation UGI International is typically party to term contracts, with approximately 45 different suppliers, including producers and international oil and gas trading companies, to meet LPG supply requirements throughout Europe. LPG supply is transported via rail and sea, and by road for shorter distances. Agreements are generally one-year terms with pricing based on internationally quoted market prices. Additionally, LPG is purchased on the European spot markets to manage supply needs. In certain geographic areas, such as the U.K. and Italy, a single supplier may provide nearly 50% or more of UGI Internationals requirements. Because UGI Internationals profitability is sensitive to changes in wholesale LPG costs, UGI International generally seeks to pass on increases in the cost of LPG to its customers. There can be no assurance, however, that UGI International will always be able to pass on product cost increases fully, or keep pace with such increases, particularly when product costs rise rapidly. Product cost increases can be triggered by periods of severe cold weather, supply interruptions, increases in the prices of base commodities such as crude oil and natural gas, or other unforeseen events. The significant increase in European natural gas prices have resulted in refineries substituting a portion of their natural gas refinery fuels with LPG, leading to a decrease in some areas in the availability of LPG. In addition, gas processing plants supplying the United Kingdom and Norway markets are injecting LPG into the natural gas grid, decreasing the overall supply of LPG from the gas processing plants. UGI International stores LPG at various storage facilities and terminals located across Europe and has interests in both primary storage facilities and secondary storage facilities. LPG stored in primary storage facilities is transported by rail and road to secondary storage facilities where LPG is loaded into cylinders or trucks equipped with tanks and then is delivered to customers. UGI International also manages an extensive logistics and transportation network and has access to seaborne import facilities. UGI International transports LPG to customers primarily through outsourced transportation providers to serve both bulk and cylinder markets. UGI International has long-term relationships with many providers of logistics and transportation services in most of its markets, and is not dependent on the services of any single transportation provider. Trade Names, Trade and Service Marks UGI International protects its intellectual property rights through tradenames, trade and service marks and foreign intellectual property laws. UGI International and its subsidiaries utilize a variety of tradenames, including, but not limited to, AmeriGas (Poland), Antargaz, AvantiGas, FLAGA, Kosan Gas and UniverGas, and related service marks to market its LPG products and services and energy marketing services. UGI International and its subsidiaries currently have tradenames, trade and service marks registered in various countries. UGI Internationals trademarks, tradenames and other proprietary rights are valuable assets and we believe that they have significant value in the marketing of our products and services. Competition and Seasonality The LPG markets in western and northern Europe are mature, with modest declines in total demand due to competition with other fossil fuels and other energy sources, conservation and macroeconomic conditions. Sales volumes are affected principally by the severity of the weather and customer migration to alternative energy forms, including natural gas, electricity, heating oil and wood. High LPG prices also may result in slower than expected growth due to customer conservation and customers seeking less expensive alternative energy sources. Conversely, high natural gas prices versus LPG prices over a period of time will result in customers seeking to migrate to LPG. In addition, government policies and incentives that favor alternative energy sources, such as heat pumps as well as wind and solar sources, can result in customers migrating to energy sources other than LPG. In addition to price, UGI International competes for customers in its various markets based on contract terms. UGI International competes locally as well as regionally in many of its service territories. Additionally, particularly in France, although UGI International supplies certain supermarket chains, it also competes with some of these supermarket chains that affiliate with LPG distributors to offer their own brands of cylinders. UGI International seeks to increase demand for its LPG cylinders through marketing and product innovations, such as the use of automatic vending machines. Because many of UGI Internationals customers use LPG for heating, sales volumes are affected principally by the severity of the temperatures during the heating season months and traditionally fluctuates from year-to-year in response to variations in weather, prices and other factors, such as conservation efforts and the economic environment. During Fiscal 2023, approximately 60% of UGI Internationals retail sales volumes occurred during the peak heating season from October through March. As a result of this seasonality, revenues are typically higher in UGI Internationals first and second fiscal quarters (October 1 through March 31). For historical information on weather statistics for UGI International, see Managements Discussion and Analysis of Financial Condition and Results of Operations. Government

Ticker: UGI, Sector: Utilities, Filed At: 2023-11-28T21:46:31-05:00

Regulation UGI Internationals business is subject to various laws and regulations at the country and local levels, as well as at the EU level, with respect to matters such as protection of the environment, the storage, transportation and handling of hazardous materials and flammable substances (including the Seveso II Directive), regulations specific to bulk tanks, cylinders and piped networks, competition, pricing, regulation of contract terms, anti-corruption (including the U.S. Foreign Corrupt Practices Act, Sapin II and the U.K. Bribery Act), data privacy and protection, and the safety of persons and property. Environmental Environmental laws and regulations may require expenditures over a long timeframe to control environmental effects. Estimates of liabilities for environmental response costs are difficult to determine with precision because of the various factors that can affect their ultimate level. These factors include, but are not limited to, the following: (i) the complexity of the site; (ii) changes in environmental laws and regulations; (iii) the number of regulatory agencies or other parties involved; (iv) new technology that renders previous technology obsolete or experience with existing technology that proves ineffective; (v) the level of remediation required; and (vi) variation between the estimated and actual period of time required to respond to an environmentally-contaminated site. EU Carbon Neutral Target In December 2019, EU leaders endorsed the objective of achieving a climate-neutral EU by 2050, with net-zero GHG emissions, and in July 2021, the European Commission adopted the European Climate Law to write this target into the law. The European Climate Law also includes a 2030 GHG reduction target of at least 55% below 1990 levels as an intermediate target. These targets are legally binding and based on an impact assessment conducted by the Commission. Data Privacy The EU adopted the GDPR, which became effective in May 2018. The GDPR expanded the EU data protection laws to all companies processing data of EU residents. It primarily focuses on unifying and strengthening the regulations dealing with the collection, processing, use and security of personal and sensitive data. Properties In addition to regional headquarter locations and sales offices throughout its service territory, UGI International has interests in ten primary storage facilities and more than 80 secondary storage facilities. Employees At September 30, 2023, UGI International had approximately 2,500 employees. MIDSTREAM MARKETING Retail Energy Marketing Our retail energy marketing business is conducted through Energy Services and its subsidiaries, and sells natural gas, RNG, liquid fuels and electricity to nearly 11,500 residential, commercial, and industrial customers at approximately 41,000 locations. In Fiscal 2023, we (i) served customers in all or portions of Pennsylvania, New Jersey, Delaware, New York, Ohio, Maryland, Virginia, North Carolina, South Carolina, Massachusetts, New Hampshire, Rhode Island, California, and the District of Columbia, (ii) distributed natural gas through the use of the distribution systems of 47 local gas utilities, and (iii) supplied power to customers through the use of the transmission and distribution lines of 20 utility systems. Historically, a majority of Energy Services commodity sales have been made under fixed-price agreements, which typically contain a take-or-pay arrangement that permits customers to purchase a fixed amount of product for a fixed price during a specified period, and requires payment even if the customer does not take delivery of the product. However, a growing number of Energy Services commodity sales are currently being made under requirements contracts, under which Energy Services is typically an exclusive supplier and will supply as much product at a fixed price as the customer requires. Energy Services manages supply cost volatility related to these agreements by (i) entering into fixed-price supply arrangements with a diverse group of suppliers, (ii) holding its own interstate pipeline transportation and storage contracts to efficiently utilize gas supplies, (iii) entering into exchange-traded futures contracts on NYMEX and ICE, (iv) entering into over-the-counter derivative arrangements with major international banks and major suppliers, (v) utilizing supply assets that it owns or manages, and (vi) utilizing financial transmission rights to hedge price risk against certain transmission costs. Energy Services also bears the risk for balancing and delivering natural gas and power to its customers under various gas pipeline and utility company tariffs. See Managements Discussion and Analysis of Financial Condition and Results of Operations - Market Risk Disclosures. Midstream Assets LNG Our midstream assets, which are owned by Energy Services and its subsidiaries, comprise a natural gas liquefaction, storage and vaporization facility in Temple, Pennsylvania, a natural gas liquefaction and storage facility in Mehoopany, Pennsylvania, liquefied natural gas vaporization and storage facilities in Steelton and Bethlehem, Pennsylvania, and three small mobile facilities located in Reading, Mount Carmel and Stroudsburg, Pennsylvania. In addition, Energy Services sells LNG to customers for use by trucks, drilling rigs, other motor vehicles and facilities located off the natural gas grid. In Fiscal 2023, Energy Services sold LNG to Mountaineer under a WVPSC-approved contract. Further, in Fiscal 2023, our Midstream Marketing segment also managed natural gas pipeline and storage contracts for utility company customers, including UGI Utilities. Natural Gas and Propane Storage Energy Services and its subsidiaries own propane storage and propane-air mixing stations in Bethlehem, Reading, Hunlock Creek and White Deer, Pennsylvania. Energy Services and its subsidiaries also operate propane storage, rail transshipment terminals and propane-air mixing stations in Steelton and Williamsport, Pennsylvania. These assets are used in Midstream Marketings energy peaking business that provides supplemental energy, primarily LNG and propane-air mixtures, to gas utilities at times of high demand (generally during periods of coldest winter weather). A wholly owned subsidiary of Energy Services owns and operates underground natural gas storage and related high pressure pipeline facilities, which have FERC approval to sell storage services at market-based rates. The storage facilities are located in the Marcellus Shale region of north-central Pennsylvania and have a total storage capacity of 15 million dekatherms and a maximum daily withdrawal quantity of 224,000 dekatherms. In Fiscal 2023, Energy Services leased approximately 82% of the firm capacity at its underground natural gas facilities to third parties. Gathering Systems and Pipelines Energy Services operates the Auburn gathering system in the Marcellus Shale region of northeastern Pennsylvania with a total pipeline system capacity of 635,000 dekatherms per day. The gathering system delivers into both the Tennessee Gas and Transcontinental Gas pipelines and receives gas from Tennessee Gas Pipeline as part of a capacity lease with UGI Utilities. Energy Services also operates a 6.5-mile pipeline, known as the Union Dale pipeline, that gathers gas in Susquehanna County and has a capacity of 100,000 dekatherms per day. In addition, Energy Services owns and operates approximately 90 miles of natural gas gathering lines, dehydration and compression facilities, known as Texas Creek, Marshlands, and Ponderosa, located in Bradford, Tioga, Lycoming, Potter and Clinton Counties, Pennsylvania. The combined capacity of these three systems is more than 250,000 dekatherms per day. Energy Services and its subsidiaries also own and operate a 35-mile, 20-inch pipeline, known as the Sunbury pipeline, with related facilities located in Snyder, Union, Northumberland, Montour, and Lycoming Counties, Pennsylvania, which has a design capacity of 200,000 dekatherms per day. In addition, Energy Services owns and operates the Mt. Bethel pipeline, which runs 12.5 miles in Northampton County, Pennsylvania and is designed to provide 72,000 dekatherms per day. Energy Services subsidiary, UGI Appalachia, consists of six natural gas gathering systems with approximately 305 miles of natural gas gathering pipelines and gas compressors and one processing plant in southwestern Pennsylvania, eastern Ohio, and the panhandle of West Virginia. In Fiscal 2022, Energy Services also acquired the remaining ownership interest in Pennant, a natural gas gathering system located in northeast Ohio and western Pennsylvania, and now has 100% ownership interest in Pennant. The UGI Appalachia assets provide natural gas gathering and processing services in the Appalachian Basin with gathering capacity of approximately 2,808,000 dekatherms per day and processing capacity of approximately 240,000 dekatherms per day. In Fiscal 2021, a subsidiary of Energy Services entered into a joint venture with Stonehenge to acquire Pine Run Midstream, LLC. Energy Services owns approximately 49% of the Pine Run Midstream joint venture with Stonehenge, and Stonehenge operates the system. The system is currently comprised of approximately 46 miles of pipeline, 40,830 HP of installed compression and dedicated production of 54,000 gross acres. The system is attached to another gathering system owned by Energy Services. In January 2022, Energy Services acquired Stonehenge Appalachia, LLC from Stonehenge Energy Holdings, LLC and subsequently renamed the system UGI Moraine East. The system consists of approximately 48 miles of pipeline and associated compression assets. Electric Generation Assets Midstream Marketing holds electric generation facilities conducted by Energy Services wholly owned subsidiary, UGID. UGID owns and operates the Hunlock Creek Energy Center located near Wilkes-Barre, Pennsylvania, a 174-megawatt natural gas-fueled electricity generating station. Additionally, UGID owns and operates 13.5 megawatts of solar-powered generation capacity in Pennsylvania, Maryland and New Jersey. Renewable Natural Gas GHI, a wholly owned subsidiary of Energy Services, purchases gas produced from landfills and biodigesters and resells the gas to fleet operators in California. Environmental credits are generated through this process, which are then sold to various third parties for an additional revenue stream. See Business Strategy Investment in Renewable Energy in this Item 1. and 2. Business and Properties for information on transactions Energy Services completed to further UGIs foundation for growth within the renewable energy space. Competition Our Midstream Marketing segment competes with other midstream operators to sell gathering, compression, storage and pipeline transportation services. Our Midstream Marketing segment competes in both the regulated and non-regulated environment against interstate and intrastate pipelines that gather, compress, process, transport and market natural gas. Our Midstream Marketing segment sells midstream services primarily to producers, marketers and utilities on the basis of price, customer service, flexibility, reliability and operational experience. The competition in the midstream segment is significant and has grown recently in the northeast U.S. as more competitors seek opportunities offered by the development of the Marcellus and Utica Shales. Our Midstream Marketing segment also competes with other marketers, consultants and local utilities to sell natural gas, liquid fuels, electric power and related services to customers in its service area principally on the basis of price, customer service and reliability. Midstream Marketings midstream asset business has faced an increase in competition in recent years with the consolidation of companies that have resulted in large, national competitors that can offer a suite of services across all customer segments. Our electricity generation assets compete with other generation stations on the interface of PJM, a regional transmission organization that coordinates the movement of wholesale electricity in certain states, including the states in which we operate, and bases sales on bid pricing. Through our wholly owned subsidiary, GHI, Energy Services has the capability to source and deliver RNG to customers throughout the U.S. GHI currently delivers RNG to transportation fleets for utilization in their compressed natural gas and LNG fueled vehicles, resulting in the creation and monetization of California Low Carbon Fuel Standard credits and Renewable Fuel Standard Renewable Identification Number credits. GHI competes with other RNG marketers and brokers on the basis of price, customer service and reliability. Further, our Midstream Marketing segment competes with other RNG project developers, which has recently become a more competitive environment. We compete to acquire the projects from the feedstock generators, which are typically farmers (for manure digesters) and landfill operators, including through offerings of joint venture ownership interests, feedstock payments and royalties. In addition, there has been significant consolidation over the past year with both agricultural and landfill RNG project owners/developers. Government Regulation FERC has jurisdiction over the rates and terms and conditions of service of wholesale sales of electric capacity and energy, as well as the sales for resale of natural gas and related storage and transportation services. Energy Services has a tariff on file with FERC, pursuant to which it may make power sales to wholesale customers at market-based rates, to the extent that Energy Services purchases power in excess of its retail customer needs. Two subsidiaries of Energy Services, UGI LNG, Inc. and UGI Storage Company, currently operate natural gas storage facilities under FERC certificate approvals and offer services to wholesale customers at FERC-approved market-based rates. Two other Energy Services subsidiaries operate natural gas pipelines that are subject to FERC regulation. UGI Mt. Bethel Pipeline Company, LLC operates a 12.5-mile, 12-inch pipeline located in Northampton County, Pennsylvania, and UGI Sunbury, LLC operates the Sunbury Pipeline, a 35-mile, 20-inch diameter pipeline located in central Pennsylvania. Both pipelines offer open-access transportation services at cost-based rates approved by FERC. Energy Services and its subsidiaries undertake various activities to maintain compliance with the FERC Standards of Conduct with respect to pipeline operations. Energy Services is also subject to FERC reporting requirements, market manipulation rules and other FERC enforcement and regulatory powers with respect to its wholesale commodity business. Midstream Marketings midstream assets include natural gas gathering pipelines and compression and processing in northeastern Pennsylvania, southwestern Pennsylvania, eastern Ohio and the panhandle of West Virginia that are regulated under federal pipeline safety laws and subject to operational oversight by both the Pipeline and Hazardous Materials Safety Administration and the state public utility commissions for the states in which the specific pipelines are located. Certain of our Midstream Marketing and RNG businesses are subject to various federal, state and local environmental, safety and transportation laws and regulations governing the storage, distribution and transportation of propane and the operation of bulk storage LPG terminals. These laws include, among others, the Resource Conservation and Recovery Act, CERCLA, the Clean Air Act, OSHA, the Homeland Security Act of 2002, the Emergency Planning and Community Right-to-Know Act, the Clean Water Act and comparable state statutes. CERCLA imposes joint and several liability on certain classes of persons considered to have contributed to the release or threatened release of a hazardous substance into the environment without regard to fault or the legality of the original conduct. With respect to the operation of natural gas gathering and transportation pipelines, Energy Services also is required to comply with the provisions of the Pipeline Safety Improvement Act of 2002 and the regulations of the DOT. Our Midstream Marketings electricity generation assets own electric generation facilities that are within the control area of PJM and are dispatched in accordance with a FERC-approved open access tariff and associated agreements administered by PJM. UGID is the entity designated for dispatching and financially settling all company owned generation and receives certain revenues collected by PJM, determined under an approved rate schedule. Like Energy Services, UGID has a tariff on file with FERC pursuant to which it may make power sales to wholesale customers at market-based rates, and FERC has approved UGIDs market-based rate authority through 2023, with approval pending through 2026. UGID is also subject to FERC reporting requirements, market manipulation rules and other FERC enforcement and regulatory powers. Employees At September 30, 2023, Midstream Marketing had approximately 380 employees. UTILITIES PA GAS UTILITY PA Gas Utility consists of the regulated natural gas distribution business of our subsidiary, UGI Utilities. PA Gas Utility serves customers in eastern and central Pennsylvania and in portions of one Maryland county, and therefore is regulated by the PAPUC and, with respect to its customers in Maryland, the MDPSC. Service Area; Revenue Analysis PA Gas Utility provides natural gas distribution services to approximately 684,000 customers in certificated portions of 46 eastern and central Pennsylvania counties through its distribution system. Contemporary materials, such as plastic or coated steel, comprise approximately 93% of PA Gas Utilitys more than 12,600 miles of gas mains, with bare steel pipe comprising approximately 6% and cast iron pipe comprising approximately 1% of PA Gas Utilitys gas mains. In accordance with PA Gas Utilitys agreement with the PAPUC, PA Gas Utility will replace the cast iron portion of its gas mains by March 2027 and the bare steel portion of its gas mains by September 2041. Located in PA Gas Utilitys service area are major production centers for basic industries such as specialty metals, aluminum, glass, paper product manufacturing and several power generation facilities. PA Gas Utility also distributes natural gas to more than 550 customers in portions of one Maryland county. System throughput (the total volume of gas sold to or transported for customers within PA Gas Utilitys distribution system) for Fiscal 2023 was approximately 324 Bcf. System sales of gas accounted for approximately 18% of system throughput, while gas transported for residential, commercial and industrial customers who bought their gas from others accounted for approximately 82% of system throughput. Sources of Supply and Pipeline Capacity PA Gas Utility is permitted to recover all prudently incurred costs of natural gas it sells to its customers. See Managements Discussion and Analysis of Financial Condition and Results of Operations - Market Risk Disclosures and Note 9 to Consolidated Financial Statements. PA Gas Utility meets its service requirements by utilizing a diverse mix of natural gas purchase contracts with marketers and producers, along with storage and transportation service contracts. These arrangements enable PA Gas Utility to purchase gas from Marcellus, Gulf Coast, Mid-Continent, and Appalachian sources. For its transportation and storage functions, PA Gas Utility has long-term agreements with a number of pipeline companies, including Texas Eastern Transmission, LP, Columbia Gas Transmission, LLC, Transcontinental Gas Pipeline Company, LLC, Eastern Gas Transmission and Storage, Inc., Tennessee Gas Pipeline Company, L.L.C., and Energy Services and its subsidiaries (including UGI Storage Company and UGI Sunbury, LLC). Gas Supply Contracts During Fiscal 2023, PA Gas Utility purchased approximately 78 Bcf of natural gas for sale to retail core-market customers (principally comprised of firm residential, commercial and industrial customers that purchase their gas from PA Gas Utility) and off-system sales customers. Approximately 96% of the volumes purchased were supplied under agreements with ten suppliers, with the remaining volumes supplied primarily by 30 producers and marketers. Gas supply contracts for PA Gas Utility vary in length by counterparty and type of supply. Typically, pipeline and storage contracts range from one to five years in length. PA Gas Utility also has long-term contracts with suppliers for natural gas peaking supply during the months of November through March. Seasonality Because many of its customers use natural gas for heating purposes, PA Gas Utilitys sales are seasonal. For Fiscal 2023, approximately 59% of PA Gas Utilitys sales volume was supplied, and approximately 90% of PA Gas Utilitys operating income was earned, during the peak heating season from October through March. Competition Natural gas is a fuel that competes with electricity and oil and, to a lesser extent, with propane and coal. Competition among these fuels is primarily a function of their comparative price and the relative cost and efficiency of the equipment. Natural gas generally benefits from a competitive price advantage over oil, electricity and propane. Fuel oil dealers compete for customers in all categories, including industrial customers. PA Gas Utility responds to this competition with marketing and sales efforts designed to retain, expand and grow its customer base. In substantially all of its service territories, PA Gas Utility is the only regulated gas distribution utility having the right, granted by the PAPUC or by law, to provide gas distribution services. All of PA Gas Utilitys customers, including core-market customers, have the right to purchase gas supplies from entities other than natural gas distribution utility companies. A number of PA Gas Utilitys commercial and industrial customers have the ability to switch to an alternate fuel at any time and, therefore, are served on an interruptible basis under rates that are competitively priced with respect to the alternate fuel. Margin from these customers, therefore, is affected by the difference or spread between the customers delivered cost of gas and the customers delivered cost of the alternate fuel, the frequency and duration of interruptions, and alternative firm service options. See Utilities Regulation - State Utility Regulation - PA Gas Utility. Approximately 74% of PA Gas Utilitys annual throughput volume for commercial and industrial customers includes customers at locations that afford them the opportunity of seeking transportation service directly from interstate pipelines, thereby bypassing PA Gas Utility. During Fiscal 2023, PA Gas Utility had 17 such customers, 15 of which have transportation contracts extending beyond Fiscal 2024. The majority of these customers are served under transportation contracts having three to 20-year terms and all are among the largest customers for PA Gas Utility in terms of annual volumes. No single customer represents, or is anticipated to represent, more than five percent of PA Gas Utilitys total revenues. Outlook for Gas Service and Supply PA Gas Utility anticipates having adequate pipeline capacity, peaking services and other sources of supply available to it to meet the full requirements of all firm customers on its system through Fiscal 2024. Supply mix is diversified, market priced and delivered pursuant to a number of long-term and short-term primary firm transportation and storage arrangements, including transportation contracts held by some of PA Gas Utilitys larger customers and natural gas suppliers serving customers on PA Gas Utilitys distribution system. During Fiscal 2023, PA Gas Utility supplied transportation service to 11 electric generation facilities and 29 major co-generation facilities. PA Gas Utility continues to seek new residential, commercial and industrial customers for both firm and interruptible service. In Fiscal 2023, PA Gas Utility connected more than 1,460 new commercial and industrial customers. In the residential market sector, PA Gas Utility added more than 11,100 residential heating customers during Fiscal 2023. Approximately 56% of these customers converted to natural gas heating from other energy sources, mainly oil and electricity. New home construction and existing non-heating gas customers who added gas heating systems to replace other energy sources primarily accounted for the other residential heating connections in Fiscal 2023. PA Gas Utility continues to monitor and participate, where appropriate, in rulemaking and individual rate and tariff proceedings before FERC affecting the rates and the terms and conditions under which PA Gas Utility transports and stores natural gas using interstate natural gas pipelines. Among these proceedings are those arising out of certain FERC orders and/or pipeline filings that relate to (i) the pricing of pipeline services in a competitive energy marketplace, (ii) the flexibility of the terms and conditions of pipeline service tariffs and contracts, and (iii) pipelines requests to increase their base rates, or change the terms and conditions of their storage and transportation services. PA Gas Utilitys objective in negotiations with providers of gas supply resources, and in proceedings before regulatory agencies, is to ensure availability of supply, transportation and storage alternatives to serve market requirements at the lowest cost possible, taking into account the need for safety, security and reliability of supply. Consistent with that objective, PA Gas Utility negotiates certain terms of firm transportation capacity on all pipelines serving it, arranges for appropriate storage and peak-shaving resources, negotiates with producers for competitively priced gas purchases and participates in regulatory proceedings related to transportation rights and costs of service. At September 30, 2023, PA Gas Utility had approximately 1,600 employees. MOUNTAINEER In September 2021, we completed the Mountaineer Acquisition, whereby Mountaineer Gas Company became an indirect, wholly owned subsidiary of UGI. Mountaineer provides a regulated natural gas distribution business to over 211,000 customers in 50 of West Virginias 55 counties. Mountaineers system is comprised of approximately 6,200 miles of distribution, transmission and gathering pipelines. Contemporary materials, such as plastic or coated steel, comprise approximately 76% of Mountaineers gas mains, with bare steel pipe comprising the remaining 24%. As of September 30, 2023, Mountaineers customer base was approximately 90% residential, and 10% commercial and industrial customers, with throughput volumes consisting of approximately 25% residential, 33% commercial and 42% industrial and other. Because many of its customers use gas for heating purposes, Mountaineers sales are seasonal. For Fiscal 2023, approximately 60% of Mountaineers sales volume (including transport volumes) was supplied, and 142% of Mountaineers operating income was earned, during the peak heating season from October through March. No single customer represents, or is anticipated to represent, more than five percent of Mountaineers total revenues. System throughput (the total volume of gas sold to or transported for customers within Mountaineers distribution system) for Fiscal 2023 was approximately 51 Bcf. Retail core-market sales of gas accounted for approximately 39% of system throughput, while gas transported for commercial and industrial customers who bought their gas from others accounted for approximately 61% of system throughput. Mountaineer anticipates having adequate pipeline capacity, peaking services and other sources of supply available to it to meet the full requirements of all firm customers on its system through Fiscal 2024. Approximately 53% of Mountaineers annual throughput volume for commercial and industrial customers represents customers who are served under interruptible rates and are also in a location near an interstate pipeline. As of September 30, 2023, Mountaineer had 19 such customers, one of which has a transportation contract extending beyond September 30, 2024. The majority of these customers, including 10 of Mountaineers largest customers in terms of annual volumes, are served under evergreen transportation contracts having a 30- to 180-day termination notice. Mountaineer meets its service requirements by utilizing a diverse mix of natural gas purchase contracts with marketers and producers, along with storage and transportation service contracts. During Fiscal 2023, Mountaineer purchased approximately 20 Bcf of natural gas for sale to retail core-market customers (principally comprised of firm-residential, commercial and industrial customers that purchase their gas from Mountaineer). Approximately 81% of the volume purchased was supplied under agreements with 10 suppliers, with the remaining volumes supplied by various producers and marketers. Gas supply contracts for Mountaineer are generally evergreen agreements with a 30-day termination notice. At September 30, 2023, Mountaineer had approximately 480 employees. ELECTRIC UTILITY Electric Utility supplies electric service to approximately 62,700 customers in portions of Luzerne and Wyoming counties in northeastern Pennsylvania through a system consisting of over 2,600 miles of transmission and distribution lines and 14 substations. For Fiscal 2023, approximately 57% of sales volume came from residential customers, 32% from commercial customers and 11% from industrial and other customers. During Fiscal 2023, 12 retail electric generation suppliers provided energy for customers representing approximately 23% of Electric Utilitys sales volume. At September 30, 2023, UGI Utilities electric utility operations had approximately 80 employees. UTILITIES REGULATION State Utility Regulation PA Gas Utility PA Gas Utility is subject to regulation by the PAPUC as to rates, terms and conditions of service, accounting matters, issuance of securities, contracts and other arrangements with affiliated entities, gas safety and various other matters. Rates that PA Gas Utility may charge for gas service come in two forms: (i) rates designed to recover PGCs; and (ii) rates designed to recover costs other than PGCs. Rates designed to recover PGCs are reviewed in PGC proceedings. Rates designed to recover costs other than PGCs are primarily established in general base rate proceedings. Act 11 of 2012 authorized the PAPUC to permit electric and gas distribution companies, between base rate cases and subject to certain conditions, to recover reasonable and prudent costs incurred to repair, improve or replace eligible property through a DSIC assessed to customers. Among other requirements, DSICs are subject to quarterly reconciliation of over-/under- collection and are capped at five percent of total customer charges absent a PAPUC-granted exception. In addition, Act 11 requires affected utilities to obtain approval of LTIIPs from the PAPUC. Act 11 also authorized electric and gas distribution companies to utilize a fully projected future test year when establishing rates in base rate cases before the PAPUC. On August 21, 2019, PA Gas Utility filed a consolidated LTIIP designed for the 2020-2024 calendar years, during which PA Gas Utility projects spending is $1.265

billion on DSIC-eligible property. PA Gas Utilitys filing was approved by the PAPUC in an order entered December 19, 2019. On September 15, 2022, the PAPUC issued a final order approving a settlement of a base rate proceeding by PA Gas Utility that permitted PA Gas Utility to implement a $49 million annual base distribution rate increase through a phased approach, with $38 million beginning October 29, 2022 and an additional $11 million beginning October 1, 2023. In accordance with the terms of the final order, PA Gas Utility will not be permitted to file a rate case prior to January 1, 2024. Also in accordance with the terms of the final order, PA Gas Utility implemented a weather normalization adjustment rider as a five-year pilot program beginning on November 1, 2022. Under this rider, customer billings for distribution services are adjusted monthly to reflect normal weather conditions where weather deviates more than three percent from normal. Additionally, under the terms of the final order, PA Gas Utility is authorized to implement a DSIC once its total property, plant and equipment less accumulated depreciation reached $3.368 billion. This threshold was achieved in September 2022 and PA Gas Utility implemented a new DSIC effective January 1, 2023. In addition to base distribution rates and various surcharges designed to recover specified types of costs, PA Gas Utilitys tariff also includes a uniform PGC rate applicable to firm retail rate schedules for customers who do not obtain natural gas supply service from an alternative supplier. The PGC rate permits recovery of all prudently incurred costs of natural gas that PA Gas Utility sells to its retail customers. PGC rates are reviewed and approved annually by the PAPUC. PA Gas Utility may request quarterly or, under certain conditions, monthly adjustments to reflect the actual cost of gas. Quarterly adjustments become effective on one days notice to the PAPUC and are subject to review during the next annual PGC filing. Each proposed annual PGC rate is required to be filed with the PAPUC six months prior to its effective date. During this period, the PAPUC investigates and may hold hearings to determine whether the proposed rate reflects a least-cost fuel procurement policy consistent with the obligation to provide safe, adequate and reliable service. After completion of these hearings, the PAPUC issues an order permitting the collection of gas costs at levels that meet such standard. The PGC mechanism also provides for an annual reconciliation and for the payment or collection of interest on over and under collections. PA Gas Utilitys gas service tariff also contains a state tax surcharge clause. The surcharge is recomputed whenever any of the tax rates included in their calculation are changed. These clauses protect PA Gas Utility from the effects of increases in certain of the Pennsylvania taxes to which it is subject. Mountaineer Mountaineer is subject to regulation of rates and other aspects of its business by the WVPSC. When necessary, Mountaineer seeks general base rate increases to recover increased operating costs and a fair return on rate base investments. Base rates are determined by the cost-of-service by rate class, and the rate design methodology allocates the majority of operating costs through volumetric charges. Mountaineer makes routine filings with the WVPSC to reflect changes in the costs of purchased gas. These purchased gas costs are subject to rate recovery through a mechanism that provides dollar-for-dollar recovery of prudently incurred costs. Costs in excess of revenues that are expected to be recovered in future rates are deferred as regulatory assets; conversely, revenues in excess of costs are deferred as a regulatory liability. The PGA filings generally cover a prospective 12-month period. The WVPSC entered a procedural order on September 9, 2022, directing all gas utilities and other parties to file proposals to reduce or levelize the impact of high natural gas costs on utilities customers in the near term. Further, WVPSC issued orders issued on November 28, 2022 and December 1, 2022 that established interim purchased gas rates. In addition, for Mountaineers residential customers only, the WVPSC created a new monthly fixed charge of $11.08 to levelize the collection of the pipeline demand charges. The WVPSC issued a final order and a further final order on April 12, 2023 and April 14, 2023, respectively, which established final purchased gas rates, keeping in place the residential pipeline demand charge of $11.08 and permitted partial recovery of interest on the unrecovered balance that was deferred. In July 2023, Mountaineer filed a PGA case, and on October 5, 2023, an interim rate order was issued that established new reduced interim rates effective November 1, 2023. All parties were directed to file further information in their final substantive recommendations regarding whether to continue the residential pipeline demand charge or return to volumetric rate recovery. The final PGA rate order is not expected until the first quarter of 2024. As permitted by West Virginia law, the WVPSC has also approved a standalone cost recovery rider to recover specified costs and a return on infrastructure projects between general base rate cases in accordance with its IREP. Mountaineer makes an annual IREP filing, which is subject to an over/under-recovery mechanism similar to purchased gas costs. In December 2022, the WVPSC issued a final order approving a settlement in Mountaineers 2023 IREP filing, resulting in an increase of $5.4 million effective January 1, 2023. In July 2023, Mountaineer submitted its annual IREP filing to the WVPSC requesting a revenue increase of $6.5 million effective January 1, 2024, based on the forecasted 2024 calendar year IREP-eligible capital investments of $67.0 million and recovery of eligible costs. An order from the WVPSC is expected in December 2023. Mountaineer filed a base rate proceeding on March 6, 2023. By statute, the WVPSC suspended the rate increase until December 31, 2023. On October 6, 2023, Mountaineer filed a joint stipulation and agreement for settlement of the base rate case, which included a net revenue increase of approximately $13.9 million, which is expected to result in an overall increase in total revenues of 4.16%. An order from the Commission is expected in December and new rates will take effect on January 1, 2024 . Electric Utility Electric Utility is permitted to recover prudently incurred electricity costs, including costs to obtain supply to meet its customers energy requirements, pursuant to a supply plan filed with and approved by the PAPUC. Electric Utility distributes electricity that it purchases from wholesale markets and electricity that customers purchase from other suppliers. On January 27, 2023, Electric Utility filed for a base rate increase with the PAPUC. On July 14, 2023, Electric Utility filed a joint petition for settlement of the rate case, which included a revenue increase of approximately $8.5 million. In an order dated September

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21, 2023, the PAPUC approved the settlement and authorized the increased rate to become effective October 1, 2023. Electric Utilitys tariff includes rates, applicable to so-called default service customers who do not obtain electric generation service from an alternative supplier, incurred pursuant to a PAPUC-approved supply plan. These default service rates are reconcilable, may be adjusted quarterly, and are designed to permit Electric Utility to recover the full costs of providing default service in a full and timely manner. Electric Utilitys default service rates include recovery of costs associated with compliance with the AEPS Act, which requires Electric Utility to directly or indirectly acquire certain percentages of its supplies from designated alternative energy sources. In an order dated January 14, 2021, the PAPUC authorized Electric Utility to implement its current Default Service plan for the period June 1, 2021 through May 31, 2025, subject to possible, prospectively applied interim modifications that parties to that proceeding may propose in accordance with a settlement filed in that proceeding on October 23, 2020. Electric Utilitys tariff also includes a DSIC surcharge mechanism that was authorized by the PAPUC in 2019. Electric Utilitys first LTIIP, approved in 2017, provided the basis for its current DSIC charges through September 30, 2022. That authority was extended by order of the PAPUC issued August 25, 2022, in which Electric Utilitys second LTIIP filing was approved, authorizing the expenditure of $50.6 million of DSIC-eligible plant over the five-year period ending September 30, 2027 . With the implementation of new base rates on October 1, 2023 pursuant to the PAPUCs September 21, 2023 order in the 2023 Electric Utility base rate case, Electric Utilitys DSIC-eligible plant associated revenue requirement was rolled into Electric Utilitys base rates. The final order issued by the PAPUC approved the settlement of the base rate proceeding and authorized Electric Utility to implement a new DSIC surcharge once Electric Utilitys total gross plant balance exceeds $275 million. Utility Franchises PA Gas Utility and Electric Utility hold certificates of public convenience issued by the PAPUC and certain grandfather rights predating the adoption of the Pennsylvania Public Utility Code and its predecessor statutes, which authorize it to carry on its business in the territories in which it renders gas service. Under applicable Pennsylvania law, PA Gas Utility and Electric Utility also have certain rights of eminent domain as well as the right to maintain their facilities in public streets and highways in their respective territories. Similarly, Mountaineer holds certificates of public convenience issued by the WVPSC, which authorize it to carry on its business in substantially all of the territories in which it now renders gas service. Under applicable West Virginia law, Mountaineer also has certain rights of eminent domain as well as the right to maintain its facilities in public streets and highways in its territories. Federal Energy Regulation With the acquisition of Mountaineer on September 1, 2021, UGI and its subsidiaries became subject to FERC regulation under PUHCA 2005 pertaining to record-keeping and affiliate service pricing requirements. UGI provided notice of its non-exempt status on September 17, 2021. Utilities is subject to Section 4A of the Natural Gas Act, which prohibits the use or employment of any manipulative or deceptive devices or contrivances in connection with the purchase or sale of natural gas or natural gas transportation subject to the jurisdiction of FERC, and FERC regulations that are designed to promote the transparency, efficiency, and integrity of gas markets. Similarly, UGI Utilities is also subject to Section 222 of the Federal Power Act, which prohibits the use or employment of any manipulative or deceptive devices or contrivances in connection with the purchase or sale of electric energy or transmission service subject to the jurisdiction of FERC, and FERC regulations that are designed to promote the transparency, efficiency, and integrity of electric markets. FERC has jurisdiction over the rates and terms and conditions of service of electric transmission facilities used for wholesale or retail choice transactions. Electric Utility owns electric transmission facilities that are within the control area of PJM and are dispatched in accordance with a FERC-approved open access tariff and associated agreements administered by PJM. PJM is a regional transmission organization that regulates and coordinates generation, supply and the wholesale delivery of electricity. Electric Utility receives certain revenues collected by PJM, determined under a formulary rate schedule that is adjusted in June of each year to reflect annual changes in Electric Utilitys electric transmission revenue requirements, when its transmission facilities are used by third parties. FERC has jurisdiction over the rates and terms and conditions of service of wholesale sales of electric capacity and energy. Electric Utility has a tariff on file with FERC pursuant to which it may make power sales to wholesale customers at market-based rates. Under provisions of EPACT 2005, Electric Utility is subject to certain electric reliability standards established by FERC and administered by an ERO. Electric Utility anticipates that substantially all the costs of complying with the ERO standards will be recoverable through its PJM formulary electric transmission rate schedule. EPACT 2005 also granted FERC authority to impose substantial civil penalties for the violation of any regulations, orders or provisions under the Federal Power Act and Natural Gas Act and clarified FERCs authority over certain utility or holding company mergers or acquisitions of electric utilities or electric transmitting utility property valued at $10 million or more. Other Government Regulation In addition to state and federal regulation discussed above, Utilities is subject to various federal, state and local laws governing environmental matters, occupational health and safety, pipeline safety and other matters. Each is subject to the requirements of the Resource Conservation and Recovery Act, CERCLA and comparable state statutes with respect to the release of hazardous substances. See Note 16 to Consolidated Financial Statements. BUSINESS SEGMENT INFORMATION The table stating the amounts of revenues, operating income and identifiable assets attributable to each of UGIs reportable business segments, and to information regarding the geographic areas in which we operate, for Fiscal 2023, Fiscal 2022 and Fiscal 2021 appears in Note 22 to Consolidated Financial Statements included in Item 15 of this Report and is incorporated herein by reference. EMPLOYEES At September 30, 2023, UGI and its subsidiaries had approximately 10,500 employees. HUMAN CAPITAL MANAGEMENT We are committed to the attraction, development, retention and safety of our employees. The following is an overview of some of our key human capital initiatives that are designed to ensure the overall well-being of our employees and other stakeholders as well as to promote workforce diversity. UGI publishes annual sustainability reports, which are available free of charge on its corporate website under ESG - Resources - Sustainability Reports. Information included in these sustainability reports is not intended to be incorporated into this Report. Workplace Safety We are committed to maintaining an effective safety culture and stressing the importance of our employees role in identifying, mitigating and reporting safety risks. We believe that the achievement of superior safety performance is both an important short- and long-term strategic initiative in managing our operations. In this regard, our policies and operational practices promote a culture where all levels of employees are responsible for safety. Safety is generally included as a component of the annual bonus calculation for executives and non-executives, reinforcing our commitment to safety across our organization. For more details as to how we integrate safety performance into our core business activities, please refer to our Health, Safety, Security and the Environment (HSSE) Policy, which is available on our website under Company - Company Policies - HSSE Policy. UGIs Board of Directors oversees safety efforts primarily through its Safety, Environmental, and Regulatory Compliance (SERC) Committee, which is responsible for the governance and oversight of health and safety matters at the Company, including compliance with applicable laws and regulations. The SERC Committee oversees the Companys practices and policies focused on protecting the health and safety of our employees, contractors, customers, the communities we serve, and the environment. Additionally, our senior management team is actively engaged in our safety programs and conducts regular reviews of safety performance metrics. These metrics are presented quarterly to the SERC Committee for review and consideration. In addition, each of our business units has a safety team that is responsible for overseeing the safety of our operations, reinforcing our values, and enhancing our safety culture within such business units. As part of our commitment to continuously improve our safety performance, UGI has implemented robust training programs that enable field employees to safely execute their job responsibilities. Our safety programs are required to comply with both OSHA and industry-specific regulations. Diversity Strategy Diversity as Part of Our Company Culture We believe that, by fostering an environment that exemplifies our core value of respect, we gain, as a Company, unique perspectives, backgrounds and varying experiences to ensure our continued long-term success. Belonging, inclusion, diversity and equity are essential to our success, and we respect and value all employees. In alignment with our efforts to promote diversity and inclusion, our Belonging, Inclusion, Diversity and Equity (BIDE) Initiative provides the organizational blueprint for achieving greater diversity and promoting respect for uniqueness of individuals and cultures and inclusion of the varied perspectives they provide. We believe the BIDE Initiative helps align our core values (safety, integrity, respect, sustainability, reliability, and excellence) with our leaderships actions and our employees work environment. The BIDE Initiative embodies and promotes internal policies with respect to setting expectations relating to our work environment, including our Code of Business Conduct and Ethics and our Anti-Harassment/Anti-Discrimination, and Human Rights policies. As part of the BIDE Initiative, we have partnerships with numerous organizations that support underrepresented populations. UGI also supports diverse segments of our workforce through employee resource groups. Employee resource groups are a key component of the BIDE Initiative. These groups are open to all employees and allow them to learn from a cultural perspective and support their colleagues through allyship. UGIs employee resource groups include the Black Organizational Leadership and Development (BOLD) resource group, the Womens Impact Network (WIN), and the Veteran Employee Team (VET). BOLD is focused on inclusion, equity, education, and empowerment for black employees and their allies, and assists leadership with communication, talent recruitment, retention and development opportunities. BOLD focuses on professional development by creating mentoring opportunities, increasing exposure through networking and career development events, broadening outreach to and recruitment of talent and sponsoring activities such as lectures featuring distinguished speakers. The group aims to support and promote UGIs BIDE Initiative by providing cultural insight from employee, customer and community partner perspectives. WIN is an organization that aims to foster an environment for women and their allies to be recruited, retained, developed and advanced as leaders throughout UGI. Membership in WIN offers exposure to various professional development opportunities, including speaker series events, group engagement activities, virtual group discussions, and partnerships with local organizations. VET focuses on recruiting and retaining veterans, as well as creating growth for and goodwill towards military veterans. VET members include Active Duty, Reserve, and National Guard veterans of the Army, Navy, Marines, Coast Guard, and Air Force, their families, and partners committed to supporting military veteran employees. Diversity in Our Leadership We believe that diversity in our Board of Directors is critical for effective governance. In assessing the Board of Directors composition, the Board of Directors and its Corporate Governance Committee ensure that our Board of Directors and its standing committees have the appropriate qualifications, skills, experience and characteristics, including diversity of perspectives, to support our business. In assessing director candidates, the Board of Directors and Corporate Governance Committee consider a number of qualifications, including independence, knowledge, judgment, character, leadership skills, education, experience, financial literacy, standing in the community and diversity of backgrounds and views, including, but not limited to, gender, race, ethnicity and national origin. The Board of Directors and Corporate Governance Committee look to complement the Board of Directors existing strengths, recognizing that diversity is a critical element to enhancing Board effectiveness. Our Board of Directors is currently comprised of 10 directors, of which three are female, two are racially diverse and one identifies as LGBTQ+. Similarly, we believe diversity of management is crucial to position our business for continued success. UGI ensures that diverse candidates are considered for all leadership positions and is committed to considering all qualified applicants in our hiring process. As part of our continued commitment to enhancing opportunities for diversity in our workforce, in Fiscal 2023 all executives had a diversity and inclusion component in their annual bonus plan. The executive team was evaluated on the effectiveness of the Companys development and implementation of a multi-dimensional strategy to deepen and improve the Companys commitment to diversity and inclusion, supporting the Companys BIDE Initiative and establishing a roadmap to achieve excellence in diversity and inclusion and branding UGI as an employer of choice for diverse candidates. Diversity in Our Workforce UGI strives for diverse representation at all levels of our business. We annually publish our workforce demographics (which reflects our EEO-1 reporting data) in our sustainability reports. We believe that by publicly disclosing our workforce demographics, we increase transparency in the composition of our workforce as well as facilitate accountability in ensuring that diverse candidates are actively considered for roles throughout the organization. Diversity as Part of Our Employee Development UGI has a global partnership with the Human Library Organization (the Human Library), a global not-for-profit learning platform that hosts personal conversations designed to challenge stigma and stereotypes and create a safe space for dialogue where topics are discussed openly between human books and their readers. The Human Library is a thought leader when it comes to diversity and inclusion in the workplace, partnering with companies that are committed to incorporating social understanding and cultural awareness as part of their business model in relation to their workforce, partnerships, clients and customers. UGI has committed to a sponsorship role with the Human Library for the creation of a digital learning platform that will expand the reach of the Human Librarys diversity experiences across the globe. UGI began working with the Human Library in Fiscal 2020 to provide diversity and inclusion education for its leadership development, supervisor training and new hire onboarding programs. Many of our employees participated in the Human Library reader sessions over the past few years. Talent Development and Support Maintaining a robust pipeline of talent is crucial to UGIs ongoing success and is a key aspect of succession planning efforts across the organization. Our leadership and human resources teams are responsible for attracting and retaining quality talent by supporting management in fostering an environment where employees feel supported and encouraged in their professional and personal development. Competition for attracting and retaining talent has increased in recent years. UGI understands this challenge and the importance of maintaining competitive compensation and benefits as well as providing appropriate training that enables growth, developmental opportunities and multiple career paths within our Company. We commit to investing in our employees through training and development programs, including mentorship, manager trainings, and leadership development programs, as well as through tuition reimbursement to promote continued professional growth. For example, UGI Global Leadership Summit is an enterprise leadership development program for high potential leaders identified for future executive roles. Rooted in research of what skills executives need most, our potential leaders learn and practice skills such as learning agility, strategic thinking, adaptability intelligence, advanced emotional intelligence and leadership presence. In addition, potential leaders engage directly with business unit leaders and executives, gaining a broader sense of UGI and the stakeholders it serves. In addition, in Fiscal 2023, UGI launched Lifecycle Leadership, which is an enterprise wide leadership development initiative providing development to all levels of leaders, including three programs: (1) People Leaders Program, for managers at all levels of the company, (2) Experienced Managers Program, for managers with three or more years of experience, and (3) Managers of Managers Program, for managers who manage two or more teams. Through our Lifecycle Leadership initiatives, our leaders complete a variety of assessments and practice strategic and tactical skills such as effective communication, time management, delegation, employee development, conflict resolution, budgeting and finance, and unconscious bias, among other skills needed for success as a leader. ITEM 1A. RISK FACTORS There are many factors that may affect our business, financial condition and results of operations, many of which are not within our control, including the following risks relating to: (1) the demand for our products and services and our ability to grow our customer base; (2) our business operations, including internal and external factors that may impact our operational continuity; (3) our international operations; (4) our supply chain and our ability to obtain and transport adequate quantities of LPG; (5) government regulation and oversight; and (6) general factors that may impact our business and our shareholders. Investors should carefully consider, together with the other information contained in this Report, the risks and uncertainties described below. Additional risks and uncertainties not currently known to us, or that we currently deem to be immaterial, also may materially affect our business, financial condition and results of operations. No priority or significance is intended by, nor should be attached to, the order in which the risk factors appear. Risks Relating to the Demand for Our Products and Services and Our Ability to Grow Our Customer Base Our business is seasonal and decreases in the demand for our energy products and services because of warmer-than-normal heating season weather or unfavorable weather conditions may adversely affect our results of operations. Because many of our customers rely on our energy products and services to heat their homes and businesses our results of operations are adversely affected by warmer-than-normal heating season weather. Weather conditions have a significant impact on the demand for our energy products and services for both heating and agricultural purposes. Accordingly, the volume of our energy products sold is at its highest during the peak heating season of October through March and is directly affected by the severity of the winter weather. For example, historically, approximately 60% to 70% of AmeriGas Propanes annual retail propane volume, 60% of UGI Internationals annual retail LPG volume, 55% to 65% of Energy Services retail natural gas volume and 60% of PA Gas Utilitys natural gas throughput (the total volume of gas sold to or transported for customers within our distribution system) has typically been sold during these months. There can be no assurance that normal winter weather in our market areas will occur in the future. In addition, our agricultural customers use LPG for purposes other than heating, including for crop drying, and unfavorable weather conditions, such as lack of precipitation, may impact the demand for LPG. Moreover, harsh weather conditions may at times impede the transportation and delivery of LPG or restrict our ability to obtain LPG from suppliers. Spikes in demand caused by weather or other factors can stress the supply chain and limit our ability to obtain additional quantities of LPG. Changes in LPG supply costs are normally passed through to customers, but time lags (between when we purchase the LPG and when the customer purchases the LPG) may result in significant gross margin fluctuations that could adversely affect our results of operations. The potential effects of climate change may affect our business, operations, supply chain and customers, which could adversely impact our financial condition and results of operations. Shifts and fluctuations in weather patterns and other environmental conditions, including temperature and precipitation levels, may affect consumer demand for our energy products and services. In addition, the potential physical effects of climate change, such as increased frequency and severity of storms, floods, fires and other climatic events, could disrupt our operations and supply chain, and cause us to incur significant costs in preparing for or responding to these effects. These or other meteorological changes could lead to increased operating costs, capital expenses or supply costs. Our commercial and residential customers may also experience the potential physical impacts of climate change and may incur significant costs in preparing for or responding to these efforts, including increasing the mix and resiliency of their energy solutions and supply, which may adversely impact their ability to pay for our products and services or decrease demand for our products and services. The impact of any one or all of the foregoing factors may adversely affect our financial condition and results of operations. In addition to the direct physical impact that climate change may have on our business, financial condition and results of operations, we may also be adversely impacted by other environmental factors, including: (i) technological advances designed to promote energy efficiency and limit environmental impact; (ii) increased competition from alternative energy sources; (iii) regulatory responses aimed at decreasing GHG emissions; and (iv) litigation or regulatory actions that address the environmental impact of our energy products and services. For more information on these risks, please refer to the following risk factors included elsewhere in this section: Energy efficiency and technology advances, as well as price induced customer conservation, may result in reduced demand for our energy products and services; Our operations may be adversely affected by competition from other energy sources; Our need to comply with, and respond to, industry-wide changes resulting from, comprehensive, complex, and sometimes unpredictable governmental regulations, including regulatory initiatives aimed at increasing competition within our industry, may increase our costs and limit our revenue growth, which may adversely affect our operating results; Our operations, financial results and cash flows may be adversely affected by existing and future global climate change laws and regulations, including with respect to GHG emission restrictions, as well as market responses thereto; and We are subject to operating and litigation risks that may not be covered by insurance. Our potential to increase revenues may be affected by the decline in retail volumes of LPG and our ability to retain and grow our customer base. The retail LPG distribution industry in the U.S. and many of the European countries in which we operate is mature and has experienced either no or modest growth (or decline) the past few years, and we do not expect significant changes to total demand in the near future. Accordingly, we expect that year-to-year industry volumes will be principally affected by weather patterns. Therefore, our ability to grow within the LPG industry is dependent on our ability to acquire other retail distributors and to achieve internal growth, which includes the continuation of the ACE, Cynch and National Accounts programs in the U.S. and expansion in Europe, as well as the success of our sales and marketing programs designed to attract and retain customers. Any failure to retain and grow our customer base and successfully acquire other distributors would have an adverse impact on our results. Our ability to successfully execute on strategic initiatives and achieve our long-term goals may be adversely affected if we are not successful in identifying and completing strategic transactions and investments, or if we are unable to realize the anticipated benefits from such strategic transactions and investments . As part of our business strategy, we have pursued, and may continue to pursue, acquisitions, joint ventures, partnerships, divestitures, dispositions, and other strategic transactions and relationships with third parties. We have grown the Company through investments in the U.S. and in international markets, and have expanded our presence in the renewable energy industry. We may choose to finance any future investments with debt, equity, cash or a combination of the three. We can give no assurances that we will find attractive investment opportunities in the future (including renewable energy opportunities), that we will be able to complete and finance these transactions on economically acceptable terms, that any investments and related transactions will not be dilutive to earnings or that any additional debt incurred to finance such investment will not affect our ability to pay dividends. Moreover, certain investments and acquisitions in the U.S. and Europe may require merger control filings with the Federal Trade Commission and the European Commission, as applicable, and commitments (such as agreements not to compete for certain businesses) or divestments of assets may be required to obtain clearance. Such commitments or divestments may adversely influence the overall economics and risk profile of the contemplated transaction. To the extent we are successful in executing these transactions, such transactions involve a number of risks. These risks include, but are not limited to, the assumption of material liabilities, including environmental liabilities, the diversion of managements attention from the management of daily operations to the integration of acquired operations, difficulties in the assimilation and retention of employees and difficulties in the assimilation of different cultures and practices and internal controls, challenges with consolidating the operations of acquired companies into our own, as well as in the assimilation of broad and geographically dispersed personnel and operations. We also may experience integration difficulties, including in implementing new systems and processes and with integrating systems and processes of companies with complex operations, which can result in inconsistencies in standards, controls, procedures and policies and may increase the risk that our internal controls are found to be ineffective. Future investments could also result in, among other things, the failure to identify material issues during due diligence, the risk of overpaying for assets, unanticipated capital expenditures, the failure to maintain effective internal control over financial reporting, recording goodwill and other intangible assets at values that ultimately may be subject to impairment charges and fluctuations in quarterly results. There can also be no assurance that our past and future investments, including our recent investments in renewable energy, will deliver the strategic, financial, operational and environmental benefits that we anticipate, nor can we be certain that strategic investments will remain available in the future. Similarly, any divestitures or dispositions of assets have inherent risks, including the inability to find potential buyers upon favorable terms, expenses associated with a divestiture, the possibility that any anticipated sale will be delayed or will not occur, the potential impact on our cash flows and results of operations, the potential delay or failure to realize the perceived strategic or financial benefits of the divestment or disposition, difficulties in the separation of operations, services, information technology, products and personnel, potential loss of customers or employees, exposure to unanticipated liabilities, unexpected costs associated with such separation, diversion of managements attention from other business concerns and potential post-closing claims for alleged breaches of related agreements, indemnification or other disputes. Further, any cost saving measures, restructurings and divestitures may result in workforce reduction and consolidation of our facilities. As a result of these actions, we may experience a loss of continuity, loss of accumulated knowledge, disruptions to our operations and inefficiency during transitional periods. These actions could also impact employee retention. In addition, we cannot be sure that these actions will be as successful in reducing our overall expenses as we expect or that we do not forego future business opportunities as a result of these actions. The failure to successfully identify, complete, implement and manage business combinations, acquisitions, divestitures and investments intended to advance our business strategy could have an adverse impact on our business, cash flows, financial condition and results of operations. Further, our long-term goal to grow our earnings per share is driven by disciplined investments and is impacted by, among other things, our ability to increase investments in our regulated utilities businesses and generate significant fee-based income in our Midstream and Marketing operations. Other factors, assumptions and beliefs of management and our Board regarding external factors, including the global economy and regulatory developments, on which our long-term goals were based may also prove to differ materially from actual future results. Accordingly, we may not achieve our stated long-term goals, or our stated long-term goals may be negatively revised, as a result of less than expected progress toward achieving these goals. Energy efficiency and technology advances, as well as price induced customer conservation, may result in reduced demand for our energy products and services. The trend toward increased energy efficiency and technological advances, including installation of improved insulation and the development of more efficient boilers and increased consumer preference for alternative heating equipment installations, such as electric heat pumps, alongside concerted conservation measures, which have been exacerbated particularly in Europe by the evolving energy crisis, may reduce the demand for our energy products. Prices for LPG and natural gas are subject to volatile fluctuations as a result of changes in supply and demand as well as other market conditions and external factors. During periods of high energy commodity costs, our prices generally increase, which may lead to customer conservation and attrition. A reduction in demand could lower our revenues and, therefore, lower our net income and adversely affect our cash flows. In addition, federal, European and/or local regulators may offer energy conservation incentives or otherwise enact laws and regulations that may require mandatory conservation measures, which would reduce the demand for our energy products. In Europe, measures are underway to decarbonize the electric generation grid, as well as residential and commercial heating, in order to achieve EU climate change objectives, including a net zero goal by 2050. For example, in 2018 the EU revised the Energy Performance of Buildings Directive (the EPBD) with the goal to create a clear path towards a low and zero-emission and decarbonized building stock in the EU by 2050. Updates to the EPBD continue to make their way through EU legislative approvals, which will establish stronger targets for management of new and existing building construction and integral heating systems that focus on low or zero carbon outcomes. For example, certain EU countries have adopted legislation mandating the replacement of existing fossil-fuel based heating systems with lower carbon solutions and requiring newly installed heating systems to operate with renewable energy sources. Over time, these various measures will impact fossil fuel consumption in Europe and the demand for our energy products. We cannot predict the materiality of the effect of future conservation measures or the effect that any technological advances in heating, conservation, energy generation or other devices might have on our operations. Our operations may be adversely affected by competition from other energy sources. Our energy products and services face competition from other energy sources, some of which are less costly for equivalent energy value. In addition, we cannot predict the effect that the development of alternative energy sources might have on our operations. Our LPG distribution businesses compete for customers against suppliers of electricity, fuel oil and natural gas. Electricity is a major competitor of LPG but is generally more expensive than LPG on a Btu equivalent basis for space heating, water heating and cooking. However, in Europe and elsewhere, climate change policies favoring electricity from renewable energy sources or the use of electric-powered equipment, such as heat pumps in heating applications, may cause changes in current relative price relationships. Moreover, notwithstanding cost or regulatory mandates or incentives, the convenience and efficiency of electricity make it an attractive energy source for consumers and developers of new homes. Fuel oil, which is a major competitor to propane, is a less environmentally attractive energy source. Furnaces and appliances that burn LPG must be upgraded to run on fuel oil and vice versa, and, therefore, a conversion from one fuel to the other requires the installation of new equipment. Our customers generally have an incentive to switch to fuel oil only if fuel oil becomes significantly less expensive than LPG, and in multiple countries, the risk of conversion to fuel oil is diminishing due to regulations that prevent or disfavor the installation and/or use of fuel oil boilers or fuel oil for heating applications. The gradual expansion of natural gas distribution systems in our service areas may continue to result in the availability of natural gas in some areas that previously depended upon LPG resulting in lower demand for LPG. Our natural gas businesses in the U.S. compete primarily with electricity and fuel oil, and, to a lesser extent, with LPG and coal. Competition among these fuels is primarily a function of their comparative price and the relative cost and efficiency of fuel utilization equipment. There can be no assurance that our natural gas revenues will not be adversely affected by this competition. The expansion, construction and development of our energy infrastructure assets subjects us to risks. We seek to grow our business through the expansion, construction and development of our energy infrastructure, including new pipelines, gathering systems, facilities and other assets. These projects are subject to state and federal regulatory oversight and require certain property rights, such as easements and rights-of-way from public and private owners, as well as regulatory approvals, including environmental and other permits and licenses. There is no assurance that we or our project partners, as applicable, will be able to obtain the necessary property rights, permits and licenses in a timely and cost-efficient manner, or at all, which may result in a delay or failure to complete a project. We may face opposition to the expansion, construction or development of new or existing pipelines, gathering systems, facilities or other assets from environmental groups, landowners, local groups and other advocates. This opposition could take many forms, including organized protests, attempts to block or sabotage our operations, intervention in regulatory or administrative proceedings involving our assets, or lawsuits or other actions designed to prevent, disrupt, or delay the development or operation of our assets and business. Failure to complete any pending or future infrastructure project may have a materially adverse impact on our financial condition and results of operations. Even if we are able to successfully complete any pending or future infrastructure project, our revenues may not increase immediately upon the expenditure of funds on a particular project or as anticipated during the lifespan of the project. As a result, there is the risk that new and expanded energy infrastructure may not achieve our expected investment returns, which could have a material adverse effect on our business, financial condition and results of operations. Risks Relating to Our Business Operations, Including Internal and External Factors that May Impact Our Operational Continuity Our review of potential strategic alternatives may not result in the approval or completion of any specific transaction or outcome, and the process of reviewing strategic alternatives or the outcome could adversely affect our business, financial condition, operations and stock price. In August 2023, we announced that our Board of Directors initiated a process to evaluate potential strategic alternatives, including cost optimization initiatives, with the intent to unlock and maximize shareholder value. Our Board has not yet established a timeline for completion of the strategic review process, and there is no assurance that the process will result in the approval or completion of any specific transaction or outcome. We are actively working with financial and legal advisors in connection with our review of potential strategic alternatives. Any potential transaction or other strategic alternative would be dependent on a number of factors that may be beyond our control, including, among other things, market conditions, industry trends, regulatory approvals, and the availability of financing for a potential transaction on reasonable terms. The process of reviewing potential strategic alternatives, including optimization of our cost structure, is time consuming, may divert the attention of our Board and management from core business operations, and may be distracting and disruptive to our business operations and long-term planning, which may cause concern to our current or potential customers, employees, investors, strategic partners and other stakeholders, and may have a material impact on our business and operating results or our internal controls and procedures, or result in increased volatility in our share price. We may incur substantial expenses associated with identifying, evaluating and negotiating potential strategic alternatives. There can be no assurance that any potential transaction or other strategic alternative, if consummated, will provide greater value to our shareholders than that reflected in the current price of our common stock. Additionally, the outcome of the strategic review may adversely impact our business, cash flows, operations, financial condition and stock price. Until the review process is concluded or developments on the progress of the strategic review are disclosed, perceived uncertainties related to our future may result in the loss of potential business opportunities, volatility in the market price of our common stock, and difficulty attracting and retaining qualified employees and business partners. Similarly, activist investors may engage in proxy solicitations or advance shareholder proposals, or otherwise attempt to affect changes and assert influence on our Board of Directors and management, which could negatively impact our business and operations and cause a distraction to our Board, management and employees. Our information technology systems and those of our third-party vendors have been the target of cybersecurity attacks in the past. If we are unable to protect our information technology systems against future service interruption, misappropriation of data, or breaches of security resulting from cybersecurity attacks or other events, or if we encounter other unforeseen difficulties in the design, implementation or operation of our information technology systems, or if our third-party vendors or service providers experience compromises to their information technology systems, our operations could be disrupted, our business and reputation may suffer, and our internal controls could be adversely affected. In the ordinary course of business, we rely on information technology systems, including the Internet and third-party hosted services, to support a variety of business processes and activities and to store sensitive data, including (i) intellectual property, (ii) our proprietary business information and that of our suppliers and business partners, (iii) personally identifiable information of our customers and employees, and (iv) data with respect to invoicing and the collection of payments, accounting, procurement, and supply chain activities. In addition, we rely on our information technology systems to process financial information and results of operations for internal reporting purposes and to comply with financial reporting, legal, and tax requirements. Cybersecurity incidents have recently increased in both frequency and magnitude and have involved malicious software and attempts to gain unauthorized access to data and systems, including ransomware attacks where a targets access to its information systems is blocked until a ransom has been paid. The White House and various regulators, including the SEC, have accordingly increased their focus on companies cybersecurity vulnerabilities and risks. Despite our security measures, our technologies, systems, and networks have been and may continue to be the target of cybersecurity attacks or information security breaches that could result in the unauthorized release, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. Due to increasingly sophisticated threat actors, we may be unable to detect, identify or prevent attacks, and even if detected, we may be unable to adequately stop, investigate or remediate our systems given the tools and techniques being used by threat actors to circumvent controls and to remove or obfuscate forensic evidence. Attacks and incidents may also occur due to malfeasance by employees or contractors, as well as human error as in the case of social engineering and phishing campaigns. A number of our employees currently work remotely full-time or on a hybrid basis; as a result, our cybersecurity program may be less effective and information technology security may be less robust for those employees. Similarly, our third-party vendors or service providers have been impacted by cybersecurity attacks and incidents and are subject to many, if not all, of the same risks and disruptions as described above. A loss of our information technology systems, or temporary interruptions in the operation of our information technology systems, or those of our third-party vendors or service providers, or any other misappropriation of data, or breaches of security could lead to investigations and fines or penalties, litigation, increased costs for compliance and for remediation or rebuilding of our systems, and could have a material adverse effect on our business, financial condition, results of operations, and reputation. In addition, an attack could provide an intruder with the ability to control or alter our pipeline operations. Such an act could result in critical pipeline failures. The efficient execution of our businesses is dependent upon the proper design, implementation and functioning of its current and future internal systems, such as the information technology systems that support our underlying business processes. Any significant failure or malfunction of such information technology systems may result in disruptions of our operations. In addition, the effectiveness of our internal controls could be adversely affected if we encounter unforeseen problems with respect to the operation of our information technology systems. Moreover, as cybersecurity incidents increase in frequency and magnitude, we may be unable to obtain cybersecurity insurance in amounts and on terms we view as adequate for our operations, including the agreement to certain indemnification provisions by our insurance providers. Our utility transmission and distribution systems, our non-utility midstream assets, and the assets of upstream interstate pipelines and other midstream providers may not operate as planned, which may increase our expenses or decrease our revenues and, thus, have an adverse impact on our financial results. Our ability to manage operational risk with respect to utility distribution and transmission and non-utility midstream assets, and the availability of natural gas delivered by interstate natural gas pipelines and midstream gathering assets is critical to our financial results. We obtain our supply from local Marcellus and Utica Shale sources, as well as other trading points in the U.S. If we experience physical capacity constraints on one or more of the interstate or intrastate natural gas pipelines that supply our businesses, we may not be able to supply our customers, which could have an adverse impact on our financial results. Our businesses also face several risks, including the breakdown or failure of, or damage to, equipment or processes (especially due to severe weather or natural disasters), accidents and other factors, including as a result of overpressurization of or damage to natural gas pipelines. Operation of our transmission and distribution systems or our midstream assets below our expectations may result in lost revenues or increased expenses, including higher maintenance costs, civil litigation and the risk of regulatory penalties. Risks Relating to Our International Operations Our international operations could be subject to increased risks, which may negatively affect our business results. We operate LPG distribution and energy marketing businesses in Europe through our subsidiaries. As a result, we face risks in conducting business abroad that we do not face domestically. Certain aspects inherent in transacting business internationally could negatively impact our operating results, including: costs and difficulties in staffing and managing international operations; disagreements and disputes with our employees represented by a works council or union; strikes and work stoppages by the employees of the Company or our suppliers and vendors; fluctuations in currency exchange rates, particularly the euro, which can affect demand for our products, increase our costs and adversely affect our profitability and reported results; new or revised regulatory requirements, including European competition and carbon emission reduction laws, that may adversely affect the terms of contracts with customers, including with respect to exclusive supply rights and usage restrictions, and stricter regulations applicable to the storage and handling of LPG; new and inconsistently enforced industry regulatory requirements, which can have an adverse effect on our competitive position; tariffs and other trade barriers; difficulties in enforcing contractual rights; local political and economic conditions as well as geopolitical conditions that could cause instability and adversely impact the global economy or specific markets, such as the war between Russia and Ukraine; and potential violations of federal regulatory requirements, including anti-bribery, anti-corruption, and anti-money laundering law, economic sanctions, the Foreign Corrupt Practices Act of 1977, as amended, and EU regulatory requirements, including the GDPR and Sapin II. In particular, certain legal and regulatory risks are associated with international business operations. We are subject to various anti-corruption, economic sanctions and trade compliance laws, rules and regulations. For example, the

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U.S. government imposes restrictions and prohibitions on transactions in certain foreign countries, including restrictions directed at oil and gas activities in Russia. U.S. laws also prohibit the improper offer, payment, promise to pay, or authorization of the payment of money or anything of value to any foreign official or political party, or to any person, knowing that all or a portion of it will be used to influence a foreign official in his or her official duties or to secure an improper advantage. Ensuring compliance with all relevant laws, rules and regulations is a complex task. Violation of one or more of these laws, rules or regulations could lead to loss of import or export privileges, civil or criminal penalties for us or our employees, or potential reputational harm, which could have a material adverse impact on earnings, cash flows and financial condition. The European energy crisis may create LPG commodity supply challenges and could negatively impact our business results. The geopolitical situation in Europe during 2022 led to a sharp decrease in natural gas imports from Russia to Europe. This decrease resulted in a significant increase in natural gas prices in Europe. Although the natural gas prices have declined from the unprecedented highs of 2022, in response to the significant price increases experienced, refineries still see an incentive to, and are substituting a portion of their natural gas refinery fuels with, LPG leading to a decrease in the availability of inland LPG as well as higher LPG costs. In addition, gas processing plants supplying the United Kingdom and Norway markets are injecting LPG into the natural gas grid, decreasing the overall supply of LPG from the gas processing plants. In this context, LPG supply patterns are substantially changing with increased reliance on sea-imports and land logistics. We anticipate that the European energy crisis and the corresponding response by refineries and gas processing plants will continue in Fiscal 2024, leading to continued commodity supply challenges in some markets, higher commodity costs that may not be able to be absorbed by our customers, particularly in the Nordic countries and our Eastern European markets, and lower consumption by our customers, among other impacts, which could have a material adverse impact on our earnings, cash flows and overall financial condition. Economic and geopolitical instability, including as a result of acts of war, have had, and could continue to have, an adverse effect on our operating results, financial condition, and cash flows. In late February 2022, Russian military forces launched significant military action against Ukraine, which has continued through the date of this Report. We do not have operations in Russia or Ukraine. Nevertheless, the outbreak of war between Russia and Ukraine and the resulting sanctions by U.S. and European governments, together with any additional future sanctions by them, could have a larger impact that expands into other geographies where we do business, including our supply chain, business partners and customers in those markets, which could result in lost sales, supply shortages, commodity price fluctuations, increased costs, transportation logistics challenges, customer credit and liquidity issues, and lost efficiencies. The acceleration of a global energy crisis, including as a result of restrictions on Russias energy exports, could similarly impact the geographies where we do business. In addition, the U.S. and Europe have commenced certain trade actions as a result of the war between Russia and Ukraine. While significant uncertainty exists with respect to this matter, the war between Russia and Ukraine and its broader impacts, including any increased trade barriers or restrictions on global trade imposed by the U.S. or Europe, or further trade measures taken by Russia or other countries in response, could have a material impact on our operating results, financial condition and cash flows. Our energy marketing business in Europe may continue to be disrupted by extreme prices and volatility in the natural gas and power markets in Europe, which have resulted in, and may continue to result in, a material negative impact on our financial results. Our natural gas and power marketing businesses have traditionally relied upon relative pricing and periods of market stability. Since the end of 2021, the European energy markets have been in an unprecedented state of volatility. The war between Russia and Ukraine and the resulting substantial reduction of natural gas imports from Russia to Europe have led to significant uncertainty in supply, including price volatility of both wholesale gas and power, and have created new risks that we have experienced and expect to continue to experience within our European energy marketing business. These risks include: (i) the ability to economically support the traditional fixed price and full requirement contracts of customers due to the significant increased cost to adjust for shifting volumes due to excess or shortage of consumption expectations; (ii) the ability to service typical portfolio needs with standard trading activities due to the limitations on purchasing cost effective services in the market; (iii) the ability to pass increased and volume deviation costs, including balancing costs, onto customers due, among other things, to timing, regulatory and contractual constraints, (iv) the ability to maintain sourcing services to customers due to the margining and liquidity constraints as well as maximum trading limits implemented by both clearing banks and wholesale counterparties on energy suppliers, and (v) the ability to economically support fixed and variable price products while offering competitive services in the market. As a result, UGI considered all scenarios with respect to the future of its energy marketing business in Europe and decided to exit this market. UGI sold its energy marketing businesses in the United Kingdom, France and Belgium and UGI continues to make progress on the wind-down of its energy marketing business in the Netherlands. The risks identified with respect to our energy marketing business in Europe have resulted in and may continue to have a material negative impact on our financial results. Risks Relating to Our Supply Chain and Our Ability to Obtain Adequate Quantities of LPG We are dependent on our principal LPG suppliers, which increases the risks from an interruption in supply and transportation. During Fiscal 2023, AmeriGas Propane purchased approximately 85% of its propane needs from 20 suppliers. If supplies from these sources were interrupted, the cost of procuring replacement supplies and transporting those supplies from alternative locations might be materially higher and, at least on a short-term basis, our earnings could be affected. Additionally, in certain geographic areas, a single supplier provides more than 50% of AmeriGas Propanes propane requirements. Disruptions in supply in these geographic areas could also have an adverse impact on our earnings. Our international businesses are similarly dependent upon their LPG suppliers. For example, during Fiscal 2023, UGI Internationals business in the United Kingdom purchased approximately 76% of its LPG needs from two suppliers and, in Italy, approximately 72% of its supply was sourced from two suppliers. If supplies from UGI Internationals principal LPG sources are interrupted, the cost of procuring replacement supplies and transporting those supplies from alternative locations might be materially higher and our earnings could be adversely affected. There is no assurance that our international businesses will be able to continue to acquire sufficient supplies of LPG to meet demand at prices or within time periods that would allow them to remain competitive. Our ability to obtain sufficient quantities of LPG is dependent on transportation facilities and providers. Spikes in demand caused by weather or other factors can limit our access to port terminals and other transportation and storage facilities, disrupt transportation and limit our ability to obtain sufficient quantities of LPG. A significant increase in port and similar fees and fuel prices may also adversely affect our transportation costs and business. Transportation providers (rail and truck) in some circumstances have limited ability to provide additional resources in times of peak demand. Moreover, the ability of our transportation providers to maintain a staff of qualified truck drivers is critical to the success of our business. Regulatory requirements and an improvement in the economy could reduce the number of eligible drivers or require us to pay higher transportation fees as our transportation providers seek to pass on additional labor costs associated with attracting and retaining drivers. Our profitability is subject to LPG pricing and inventory risk. The retail LPG business is a margin-based business in which gross profits are dependent upon the excess of the sales price over LPG supply costs. LPG is a commodity, and, as such, its unit price is subject to fluctuations in response to changes in supply or other market conditions. We have no control over supplies, commodity prices or market conditions. Consequently, the unit price of the LPG that our subsidiaries and other distributors and marketers purchase can change rapidly over a short period of time. Most of our domestic LPG product supply contracts permit suppliers to charge posted prices at the time of delivery or negotiated prices based on the current industry index prices established at major U.S. storage points such as Mont Belvieu, Texas or Conway, Kansas. Most of our international LPG supply contracts are based on internationally quoted market prices. We also purchase a portion of our supplies in the spot market. Because our subsidiaries profitability is sensitive to changes in wholesale LPG supply costs, we will be adversely affected if we cannot pass on increases in the cost of LPG to our customers, or if there is a delay in passing on such cost increases. Due to competitive pricing in the industry, our subsidiaries may not fully be able to pass on product cost increases to our customers when product costs rise, or when our competitors do not raise their product prices in a timely manner. Finally, market volatility may cause our subsidiaries to sell LPG at less than the price at which they purchased it, which would adversely affect our operating results. We offer our customers various fixed-price LPG programs, and a significant number of our customers utilize our fixed-price programs. In order to manage the price risk from offering these services, we utilize our physical inventory position, supplemented by forward commodity transactions with various third parties having terms and volumes substantially the same as our customers contracts, but there can be no assurance that such measures will be effective. In periods of high LPG price volatility, the fixed-price programs create exposure to over or under-supply positions as the demand from customers may significantly exceed or fall short of supply procured. In addition, if LPG prices decline significantly subsequent to customers signing up for a fixed-price program, there is a risk that customers will default on their commitments, adversely affecting our results of operations. Changes in commodity market prices may have a significant negative effect on our liquidity. Depending on the terms of our contracts with suppliers as well as our use of financial instruments to reduce volatility in the cost of LPG and natural gas, changes in the market price of LPG and natural gas can create margin payment obligations for us and expose us to increased liquidity risk. In addition, increased demand for domestically produced LPG and natural gas overseas may, depending on production volumes in the U.S., result in higher domestic prices and expose us to additional liquidity risks. Supplier and derivative counterparty defaults may have a negative effect on our operating results. When we enter into fixed-price sales contracts with customers, we typically enter into fixed-price purchase contracts with suppliers. Depending on changes in the market prices of products compared to the prices secured in our contracts with suppliers of LPG, natural gas and electricity, a default of or force majeure by one or more of our suppliers under such contracts could cause us to purchase those commodities at higher prices from alternate suppliers, which would have a negative impact on our operating results. Additionally, we economically hedge the market risk associated with a substantial portion of our supply purchases using certain derivative instruments. Such changes in market prices of the aforementioned commodities could result in material exposures or significant concentrations of balances with derivative counterparties. If certain counterparties were unable to meet the obligations set forth in these derivative contracts and we were unable to fully mitigate this exposure via collateral deposit requirements and master netting arrangements, such outcomes could result in a negative effect on our operating results. Our business is dependent on the domestic and global supply chain to ensure that equipment, materials and other resources are available to both expand and maintain services in a safe and reliable manner. Moreover, prices of equipment, materials and other resources have increased recently and may continue to increase in the future. Failure to secure equipment, materials and other resources on economically acceptable terms may adversely impact our financial condition and results of operations. Current domestic and global supply chain issues are delaying the delivery, and in some cases resulting in shortages of, materials, equipment and other resources that are critical to our business operations. Failure to eliminate or manage the constraints in the supply chain may impact the availability of items that are necessary to support normal operations as well as materials that are required for continued infrastructure growth, including the replacement of end-of-life assets. Moreover, inflation has been and continues to be an area of increasing economic concern, both domestically and internationally. Changes in the costs of providing our energy products and services, including price increases in equipment and materials as well as increases in labor and distribution costs, have negatively impacted, and may continue to negatively impact, our financial condition and results of operations and/or result in corresponding price increases for the energy products and services we offer our customers. Risks Relating to Government Regulation and Oversight Regulators may not approve the rates we request and existing rates may be challenged, which may adversely affect our results of operations. In our Utilities segment, our distribution operations are subject to regulation by the PAPUC, WVPSC and MDPSC, depending on the state in which the operations are located. These regulatory bodies, among other things, approve the rates that Utilities may charge utility customers, thus impacting the returns that Utilities may earn on the assets that are dedicated to its operations. Utilities periodically files, and we expect to continue to periodically file, requests with these regulatory bodies to increase base rates charged to customers in the respective states in which Utilities operates. If Utilities is required in a rate proceeding to reduce the rates it charges its utility customers, or is unable to obtain approval for timely rate increases from the appropriate regulatory body, particularly when necessary to cover increased costs, Utilities revenue growth will be limited and earnings may decrease. The enactment of proposed or future tax legislation may adversely impact our financial condition and results of operations. We continue to assess the impact of various U.S. federal, state, local and international legislative proposals that could result in a material increase to our U.S. federal, state, local and/or international taxes. We cannot predict what impact, if any, changes in federal policy, including tax policies, will have on our industry or whether any specific legislation will be enacted or the terms of any such legislation. However, if such proposals were to be enacted, or if modifications were to be made to certain existing regulations, the consequences could have a material adverse impact on us, including increasing our tax burden, increasing our cost of tax compliance or otherwise adversely affecting our financial position, results of operations, cash flows and liquidity. Changes in applicable U.S. or foreign tax laws and regulations, or their interpretation and application, including the possibility of retroactive effect, could affect our tax expense and profitability. Such impact may also be affected positively or negatively by subsequent potential judicial interpretation or related regulation or legislation which cannot be predicted with certainty. Our need to comply with, and respond to, industry-wide changes resulting from, comprehensive, complex, and sometimes unpredictable governmental regulations, including regulatory initiatives aimed at increasing competition within our industry, may increase our costs and limit our revenue growth, which may adversely affect our operating results. While we generally refer to our Utilities segment as our regulated segment, there are many governmental regulations that have an impact on all of our businesses. Currently, we are subject to extensive and changing international, federal, state, and local laws and regulations including, but not limited to, safety, health, transportation, tax, and environmental laws and regulations that govern the marketing, storage, distribution, and transportation of our energy products. Moreover, existing statutes and regulations may be revised or reinterpreted and new laws and regulations may be adopted or become applicable to us that may affect our businesses in ways that we cannot predict. New regulations, or a change in the interpretation of existing regulations, could result in increased expenditures. In addition, for many of our operations, we are required to obtain permits from regulatory authorities and, in some cases, such regulatory permits could subject our operations to additional regulations and standards of conduct. Failure to obtain or comply with these permits or applicable regulations and standards of conduct could result in civil and criminal fines or the cessation of the operations in violation. Governmental regulations and policies in the U.S. and Europe may provide for subsidies or incentives to customers who use alternative fuels instead of carbon fuels. The EU has committed to cut CO 2 emissions and EU member states are proposing and implementing a range of subsidies and incentives to achieve the EUs climate change goals. These subsidies and incentives may result in reduced demand for our energy products and services. We are investigating and remediating contamination at a number of present and former operating sites in the U.S., including former sites where we or our former subsidiaries operated MGPs. We have also received claims from third parties that allege that we are responsible for costs to clean up properties where we or our former subsidiaries operated a MGP or conducted other operations. Most of the costs we incur to remediate sites outside of Pennsylvania cannot currently be recovered in PAPUC rate proceedings, and insurance may not cover all or even part of these costs. Our actual costs to clean up these sites may exceed our current estimates due to factors beyond our control, such as: the discovery of presently unknown conditions; changes in environmental laws and regulations; judicial rejection of our legal defenses to third-party claims; or the insolvency of other responsible parties at the sites at which we are involved. Moreover, if we discover additional contaminated sites, we could be required to incur material costs, which would reduce our net income. We also may be unable to timely respond to changes within the energy and utility sectors that may result from regulatory initiatives to further increase competition within our industry. Such regulatory initiatives may create opportunities for additional competitors to grow their business or enter our markets and, as a result, we may be unable to maintain our revenues or continue to pursue our current business strategy. Our operations, financial results and cash flows may be adversely affected by existing and future global climate change laws and regulations, including with respect to GHG emission restrictions, as well as market responses thereto. Climate change continues to attract considerable public and scientific attention in the U.S. and in foreign countries. As a result, numerous proposals have been made, and could continue to be made, at the international, national, regional, state and local levels of government to monitor and limit GHG emissions and climate impact. These efforts have included consideration of, among other things, cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. Increased regulation of GHG emissions, or climate impact generally, could have significant additional adverse impacts on us as well as our suppliers, vendors, and customers. The adoption and implementation of any laws or regulations imposing obligations on, or limiting GHG emissions from, our equipment and operations could require us to incur significant costs to reduce GHG emissions associated with our operations or could adversely affect demand for our energy products. The potential increase in our operating costs could include, but are not limited to, new costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our GHG emissions, pay taxes related to our GHG emissions, administer and manage a GHG emissions reduction program, and adversely impact the value of certain assets. We may not be able to pass on resulting increases in costs to customers. In addition, changes in regulatory policies that result in a reduction in the demand for hydrocarbon products and carbon-emitting fuel sources that are deemed to contribute to climate change, or restrict the use of such products or fuel sources, may reduce volumes available to us for processing, transportation, marketing and storage and could cause increases in costs or production disruptions. These developments could have a material adverse effect on our results of operations, financial results, valuation and useful life of assets, and cash flows. Changes in data privacy and data protection laws and regulations or any failure to comply with such laws and regulations, could adversely affect our business and financial results. As part of our operations, we collect, use, store and transfer the personal information and data of our employees as well as customer, vendor and supplier data in and across various jurisdictions. There has been increased public attention regarding the use of personal information and data transfers, accompanied by legislation and regulations intended to strengthen data protection, information security and consumer and personal privacy. The laws in these areas continue to develop and the changing nature of data protection, information security and privacy laws in the U.S., the EU and elsewhere could impact our processing of the personal information and data of our employees, vendors, suppliers and customers, which could lead to increased operating costs. Existing and emerging laws and regulations are inconsistent across jurisdictions and are subject to evolving, differing, and sometimes conflicting interpretations. The EU adopted the GDPR, which expanded EU data protections, in certain circumstances, to companies outside of the EU processing data of EU residents, regardless of whether the processing occurs in the EU. Similarly, the State of California legislature passed the California Consumer Privacy Act of 2018 (the CCPA) and the California Privacy Rights Act (the CPRA), which, among other things, grant a number of rights to California residents with respect to their personal information, and require companies to make extensive disclosures to consumers about such companies data collection, use, and sharing practices and inform consumers of their personal information rights. In addition, the CPRA created a new state privacy regulator, which will likely result in greater regulatory activity and enforcement in the privacy area. Comprehensive privacy laws with some similarities to the CCPA and CPRA have been proposed or passed at the U.S. federal and state levels, such as the Virginia Consumer Data Protection Act (the VCDPA) and the

Colorado Privacy Act (the CPA). Additionally, the Federal Trade Commission and many state attorneys general are interpreting federal and state consumer protection laws to impose standards for the online collection, use, dissemination and security of data as well as requiring disclosures about these practices. We expect that there will continue to be new laws, regulations and industry standards concerning data privacy and data protection, including artificial intelligence, in the U.S., the EU and other jurisdictions, and we cannot yet determine the impact such laws, regulations, interpretations and standards may have on our business. While we have invested significant time and resources in our GDPR and U.S. privacy law compliance program, emerging and changing data privacy and data protection requirements as well as other new and upcoming European and U.S. federal and state privacy and cybersecurity laws and industry standards may cause us to incur substantial fines, additional significant costs or require us to change our business practices. Any failure or perceived failure to comply may result in proceedings or actions against us by government entities or individuals, including class actions. Moreover, any inquiries or investigations, any other government actions or any actions by individuals may be costly to comply with, result in negative publicity, increase our operating costs, require significant management time and attention and subject us to remedies that may harm our business, including fines, demands or orders that we modify or cease existing business practices. The provisions of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), related regulations, and the rules adopted thereunder and other regulations, including the European Market Infrastructure Regulation (the EMIR), may have an adverse effect on our ability to use derivative instruments to hedge risks associated with our business. Our derivative hedging activities are subject to Title VII of the Dodd-Frank Act, which regulates the over-the-counter derivatives market and entities that participate in that market. The Dodd-Frank Act requires the CFTC and the federal banking regulators to implement the Dodd-Frank Acts provisions through rulemaking, including rules regarding mandatory clearing, trade execution and margin requirements. We have and expect to continue to qualify for and rely upon an exception from mandatory clearing and trade execution requirements for swaps entered into by commercial end-users to hedge commercial risks. In addition to relief from the clearing mandate, we also expect to continue to qualify for an exception for non-financial end-users from the margin requirements on uncleared swaps. If we are not able to do so and have to post margin supporting our uncleared swaps in the future, our costs of entering into and maintaining swaps would be increased. Based on information available as of the date of this Report, the effect of such requirements will be likely to (directly or indirectly) increase our overall costs of entering into derivatives transactions. In particular, new margin requirements, position limits and significantly higher capital charges resulting from new global capital regulations, even if not directly applicable to us, may cause an increase in the pricing of derivatives transactions entered into by market participants to whom such requirements apply or affect our overall ability to enter into derivatives transactions with certain counterparties. While costs imposed directly on us due to regulatory requirements for derivatives under the Dodd-Frank Act, such as reporting, recordkeeping and electing the end-user exception from mandatory clearing, are relatively minor, costs imposed upon our counterparties may increase the cost of our doing business in the derivatives markets to the extent such costs are passed on to us. The EMIR may result in increased costs for over-the-counter derivative counterparties trading in the EU and may also lead to an increase in the costs of, and demand for, the liquid collateral that the EMIR requires central counterparties to accept. Although we expect to continue to qualify as a non-financial counterparty under the EMIR, and thus not be required to post margin, we are currently subject to limited derivatives reporting requirements that could expand in the future, and may also be subject to increased regulatory requirements, including recordkeeping, marking to market, timely confirmations, portfolio reconciliation and dispute resolution procedures. Provisions under the EMIR could significantly increase the cost of derivatives contracts, materially alter the terms of derivatives contracts and reduce the availability of derivatives to protect against risks that we encounter. The increased trading costs and collateral costs may have an adverse impact on our business, contracts, financial condition, operating results, cash flow, liquidity and prospects. General Risks that May Impact Our Business and Our Shareholders The inability to attract, develop, retain and engage key employees could adversely affect our ability to execute our strategic, operational and financial plans. We are dependent upon the continued service and contributions of our management and key technical and professional employees, as well as our ability to transfer the knowledge and expertise of our workforce to new employees as our employees retire or we otherwise experience employee turnover. In addition, the success of our operations depends on our ability to identify, attract and develop skilled and experienced key employees. There is increased competition for experienced management and technical and professional employees, which could increase the costs associated with identifying, attracting and retaining such individuals. We may not be able to attract, retain or engage key employees if our compensation and benefits program is not as robust as the compensation and benefits programs offered by other employers for similar roles. Further, a lack of employee engagement could lead to loss of productivity and increased employee burnout, turnover, absenteeism, safety incidents as well as decreased customer satisfaction. Additionally, uncertainty as a result of our ongoing review of strategic alternatives could negatively impact our ability to recruit and retain key employees. If we cannot identify, attract, develop, retain and engage management, technical and professional employees, along with other qualified employees, to support the various functions of our business, our operations and financial performance could be adversely impacted. We may not be able to collect on the accounts of our customers. We depend on the viability of our customers for collections of accounts receivable and notes receivable. Moreover, our businesses serve numerous retail customers, and as we grow our businesses organically and through acquisitions, our retail customer base is expected to expand. There can be no assurance that our customers will not experience financial difficulties in the future or that we will be able to collect all of our outstanding accounts receivable or notes receivable. Any such nonpayment by our customers could adversely affect our business. We are subject to operating and litigation risks that may not be covered by insurance. Our business operations are subject to all of the operating hazards and risks normally incidental to the handling, storage and distribution of combustible products, such as LPG and natural gas, and the generation of electricity. These risks could result in substantial losses due to personal injury and/or loss of life, and severe damage to and destruction of property and equipment arising from explosions and other catastrophic events, including acts of terrorism. As a result of these and other incidents, we are sometimes a defendant in legal proceedings and litigation arising in the ordinary course of business, including regulatory investigations, claims, lawsuits and other proceedings. Additionally, environmental contamination or other incidents resulting in an environmental impact have resulted in, and could continue to result in, legal or regulatory proceedings (see Our need to comply with, and respond to, industry-wide changes resulting from, comprehensive, complex, and sometimes unpredictable governmental regulations, including regulatory initiatives aimed at increasing competition within our industry, may increase our costs and limit our revenue growth, which may adversely affect our operating results for more information on such proceedings). There can be no assurance that our insurance coverage will be adequate to protect us from all material expenses related to pending and future claims or that such levels of insurance would be available in the future at economical prices. Moreover, defense and settlement costs may be substantial, even with respect to claims and investigations that have no merit. If we cannot resolve these matters favorably, our business, financial condition, results of operations and future prospects may be materially adversely affected. The risk of natural disasters, pandemics and catastrophic events, including acts of war and terrorism, may adversely affect the economy and the price and availability of LPG, other refined fuels and natural gas. Natural disasters, pandemics and catastrophic events, such as fires, earthquakes, explosions, floods, tornadoes, hurricanes, terrorist attacks, war (including conflict in the Middle East), political unrest and other similar occurrences, may adversely impact the demand for, price and availability of LPG (including propane), other refined fuels and natural gas, which could adversely impact our financial condition and results of operations, our ability to raise capital and our future growth. The impact that the foregoing may have on our industries in general, and on us in particular, is not known at this time. A natural disaster, pandemic or an act of war or terrorism could result in disruptions of crude oil or natural gas supplies and markets (the sources of LPG), cause price volatility in the cost of LPG, fuel oil and natural gas, and our infrastructure facilities could be directly or indirectly impacted. Additionally, if our means of supply transportation, such as rail, truck or pipeline, are delayed or temporarily unavailable due to a natural disaster, pandemic, war or terrorist activity, we may be unable to transport LPG and other refined fuels in a timely manner or at all. A lower level of economic activity could result in a decline in energy consumption, which could adversely affect our revenues or restrict our future growth. Instability in the financial markets as a result of a natural disaster, pandemic, war or terrorism could also affect our ability to raise capital. We have opted to purchase insurance coverage for natural disasters and terrorist acts within our property and casualty insurance programs, but we can give no assurance that our insurance coverage would be adequate to fully compensate us for any losses to our business or property resulting from natural disasters or terrorist acts. Our indebtedness may adversely affect our business, financial condition and operating results. Our debt agreements also contain covenants that restrict our operational flexibility. As of September 30, 2023, we had total indebtedness of approximately $7 billion. Our indebtedness could adversely affect our business, financial condition, operating results and operational flexibility by, among other things: impairing our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions or other purposes limiting operational flexibility and our ability to pursue business opportunities and implement certain business strategies; impairing our ability to respond to changing business and economic conditions; impairing our ability to repay our indebtedness at maturity, especially where our debt agreements contain significant maturities; exposing us to the risk of increased interest rates where our debt agreements have variable interest rates; and placing us at a competitive disadvantage compared to our competitors that have proportionately less debt and fewer guarantee obligations. The occurrence of any of such events could have a material adverse effect upon our business, financial condition and results of operations. Further, if our credit ratings were to be downgraded, or general market conditions were to ascribe higher risk to our rating levels, our industry, or us, our access to capital and the cost of any future debt financing could be negatively impacted. Additionally, our ability to make payments of principal and interest on our indebtedness depends upon our future performance, which is subject to economic and political conditions, seasonal cycles and financial, business and other factors, many of which are beyond our control. If we are unable to generate sufficient cash flow from operations to service our indebtedness, we may be required to, among other things, refinance or restructure all or a portion of our indebtedness, reduce or delay planned capital or operating expenditures or sell selected assets. Such measures might not be sufficient to enable us to service our indebtedness, and any such refinancing, restructuring or sale of assets might not be available on favorable terms or at all. In addition, our debt agreements generally contain customary affirmative covenants, including, among others, covenants pertaining to the delivery of financial statements; certain financial covenants; notices of default and certain other material events; payment of obligations; preservation of corporate existence, rights, privileges, permits, licenses, franchises and intellectual property; maintenance of property and insurance and compliance with laws, as well as customary negative covenants, including, among others, limitations on the incurrence of liens, investments and indebtedness; mergers, acquisitions and certain other fundamental changes; transfers, leases or dispositions of assets outside the ordinary course of business restricted payments; changes in our line of business transactions with affiliates and burdensome agreements. These covenants could affect our ability to operate our business, respond to changes in business and economic conditions, obtain additional financing (if needed), and may increase the amount of interest expense we ultimately pay pursuant to the debt agreements. Further, our ability to comply with the covenants and restrictions contained in our debt agreements may be affected by events beyond our control, including prevailing economic, financial and industry conditions or regulatory changes. A failure to comply with the covenants in our debt agreements could result in a default or an event of default. Upon an event of default, unless waived, the lenders could elect to terminate their commitments, cease making further loans, require cash collateralization of letters of credit, cause their loans to become due and payable in full, foreclose against any assets securing the debt under our debt agreements and force us and our subsidiaries into bankruptcy or liquidation. If the payment of our debt is accelerated, we cannot be certain that we will have sufficient funds available to pay down the indebtedness (together with accrued interest and fees), or that we will have the ability to refinance the accelerated indebtedness on terms favorable to us or at all. This could have a material adverse effect upon our business, financial condition and results of operations. Additionally, the terms of future debt agreements could include more restrictive covenants, or require incremental collateral, which may further restrict our business operations or conflict with covenant restrictions then in effect. As a result, there is no guarantee that financings will be available in the future to fund our obligations, or that they will be available on terms consistent with our expectations. See the liquidity section in Item 7. Management's Discussion and Analysis for additional information on our current debt agreements. An impairment of our assets could adversely affect our financial condition and results of operations . We test goodwill, intangible, and other long-lived assets for impairment annually or whenever events or circumstances indicate impairment may have occurred. To the extent the value of goodwill or long-lived assets becomes impaired, the Company may be required to incur impairment charges that could have a material impact on our results of operations. The testing of assets for impairment requires us to make significant estimates about our future events, including our performance and projected cash flows, as well as other assumptions. These estimates can be affected by numerous factors, including developments in the global economic environment, including the prospect of higher interest rates, developments in regulatory, industry and market conditions, changes in business operations, changes in competition or changes in technologies. Any changes in key assumptions, or actual performance compared with key assumptions, about our business and its future prospects could affect the fair value of one or more of our assets, which may result in an impairment charge. We have incurred and may continue to incur impairment charges on certain of our assets that could have a material impact on our results of operations. Our holding company structure could limit our ability to pay dividends or service debt. We are a holding company whose material assets are the stock of our subsidiaries. Our ability to pay dividends on our Common Stock and to pay principal and accrued interest on our debt, if any, depends on the payment of dividends to us by our principal subsidiaries. Payments to us by our subsidiaries, in turn, depend upon their consolidated results of operations and cash flows. The operations of our subsidiaries are affected by conditions beyond our control, including weather, regulations, competition in national and international markets we serve, the costs and availability of propane, butane, natural gas, electricity, and other energy sources, capital market conditions and interest rates and other business risks impacting liquidity levels. The ability of our subsidiaries to make payments to us is also affected by the level of indebtedness of our subsidiaries, which is substantial, and the restrictions on payments to us imposed under the terms of such indebtedness. Volatility in credit and capital markets may restrict our ability to grow, increase the likelihood of defaults by our suppliers and vendors, customers and counterparties and adversely affect our operating results. Volatility in credit and capital markets may create additional risks to our businesses in the future. We are exposed to financial market risk (including refinancing risk) resulting from factors beyond our control, including, among other things, commodity price volatility and changes in interest rates and conditions in the credit and capital markets. Adverse developments in the credit markets may increase our possible exposure to the liquidity, default and credit risks of our suppliers and vendors, counterparties associated with derivative financial instruments and our customers. We depend on our intellectual property and failure to protect that intellectual property could adversely affect us. We seek trademark protection for our brands in each of our businesses, and we invest significant resources in developing our business brands. Failure to maintain our trademarks and brands could adversely affect our customer-facing businesses and our operational results. Declines in the stock market or bond market, and a low interest rate environment, may negatively impact our pension liability. Declines in the stock market and a low interest rate environment historically have resulted in a significant impact on our pension liability and funded status. Declines in the stock or bond market and valuation of stocks or bonds, combined with low interest rates, could further impact our pension liability and funded status and increase the amount of required contributions to our pension plans. Unless we otherwise consent in writing, our Amended and Restated Bylaws designate a state court located in Montgomery County, Pennsylvania or, if no state court located within such county has jurisdiction over such action or proceeding, the federal United States District Court for the Eastern District of Pennsylvania, as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our shareholders, which could discourage lawsuits against us and our directors and officers. Our Amended and Restated Bylaws provide that, unless we otherwise consent in writing, a state court located in Montgomery County, Pennsylvania or, if no state court located within such county has jurisdiction over such action or proceeding, the federal United States District Court for the Eastern District of Pennsylvania, as the sole and exclusive forum for: (a) any derivative action or proceeding brought on behalf of us; (b) any action or proceeding asserting a claim of breach of duty owed to us or our shareholders by any director, officer, or other employee of ours; (c) any action or proceeding asserting a claim against us or against any of our directors, officers or other employees arising pursuant to, or involving any interpretation or enforcement of, any provision of the Pennsylvania Associations Code, Pennsylvania Business Corporation Law of 1988, or our Amended and Restated Articles of Incorporation or Amended and Restated Bylaws; and (d) any action or proceeding asserting a claim peculiar to the relationship between or among us and our officers, directors, and shareholders, or otherwise governed by or involving the internal affairs doctrine. This exclusive forum provision does not apply to suits brought to enforce a duty or liability created by the Exchange Act or the Securities Act. This exclusive forum provision may limit the ability of our shareholders to bring a claim in a judicial forum that such shareholders find favorable for disputes with us or our directors or officers, which may discourage such lawsuits against us and our directors and officers. Alternatively, if a court outside of Pennsylvania were to find this exclusive forum provision inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings described above, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, results of operations and financial condition.

Item 1. BUSINESS References in this report to "we," "our," "us" and "the Company" are to Vistra and/or its subsidiaries, as apparent in the context. See Glossary for defined terms. Business Vistra is a holding company operating an integrated retail and electric power generation business primarily in markets throughout the U.S. Through our subsidiaries, we are engaged in competitive energy market activities including electricity generation, wholesale energy sales and purchases, commodity risk management and retail sales of electricity and natural gas to end users. We incorporated under Delaware law in 2016. Effective July 2, 2020, we changed our name from Vistra Energy Corp. to Vistra Corp. to distinguish from companies that are involved in exploring for, producing, refining, or transporting fossil fuels (many of which use "energy" in their names) and to better reflect our integrated business model, which combines a retail electricity and natural gas business focused on serving its customers with new and innovative products and services and an electric power generation business leading the clean power transition through our Vistra Zero portfolio while powering the communities we serve with safe, reliable and affordable power. We serve approximately 3.5 million customers and operate in 20 states and the District of Columbia. Our generation fleet totals approximately 37,000 MW of generation capacity with a portfolio of natural gas, nuclear, coal, solar and battery energy storage facilities. Vistra has six reportable segments: (i) Retail, (ii) Texas, (iii) East, (iv) West, (v) Sunset and (vi) Asset Closure. See Market Discussion below and Note 19 to the Financial Statements for further information concerning our reportable segments. Business Strategy Vistra is a leader in the clean power transition. With a strong zero-carbon generation portfolio and a deliberate and responsible strategy to decarbonize, the company is focused on delivering healthy returns and value for all stakeholders. Our business strategy is focused on the following areas: Growth and transformation. Vistra's strategy is to responsibly and reliably grow our businesses through economically attractive investments, including in retail business and renewable, energy storage and other assets that assist in reducing our carbon footprint and create a more sustainable and resilient company well positioned to generate long-term value for all of our stakeholders. Since 2010, Vistra has retired more than 14,500 MW of coal and gas power plants resulting in a 45% reduction in carbon dioxide (CO_2) emissions, a 61% reduction in nitrogen oxide (NO_X) emissions, and a 81% reduction in sulfur dioxide (SO_2) emissions through year-end 2022, compared to a 2010 baseline. Now, we are transforming our generation portfolio through investments in zero-carbon resources and new carbon-reducing technologies, targeting net-zero carbon emissions by 2050. Additionally, we have announced the retirement of approximately 5,000 MW of coal-fueled power plants by 2027, with plans to repurpose feasible sites to solar and energy storage developments. Repurposed sites provide a strategic advantage in the development of greener power due to the interconnection infrastructure already available, but additionally, and importantly, they allow us to continue supporting the local communities and our employees in those areas. We believe our diversified asset mix will support the reliability of the electric system while providing customers with cost-effective energy that meets their sustainable preferences throughout the clean power transition. Our growth strategy leverages our core capabilities of multi-channel retail marketing in large and competitive markets, operating large-scale, environmentally sensitive, and diverse assets across a variety of fuel technologies, fuel logistics and management, commodity risk management, cost control, and energy infrastructure investing. To advance our sustainability and energy transition initiatives, in December 2021, we adopted our Green Finance Framework, pursuant to which we issued $1.0 billion of Series B Preferred Stock to finance or refinance, in whole or in part, new or existing eligible green projects. We intend to opportunistically evaluate the acquisition and development of high-quality generation and storage assets and power-related businesses, including retail businesses and renewable, energy storage and other assets, that complement our core capabilities and align with our operational, financial and sustainability goals. We pride ourselves on our deliberate and responsible approach to grow and transform, considering impacts on all stakeholders. We make disciplined investments that are consistent with our focus on maintaining both a strong balance sheet and strong liquidity profile and our commitment to ensuring grid reliability, affordable power, and pursuit of a just transition away from carbon-emitting generation assets for the communities in which we operate and serve. As a result, consistent with our disciplined capital allocation approval process, we endeavor to pursue growth opportunities that have compelling economic value and align with or enhance our purpose and core principles. Disciplined capital allocation. Vistra takes a disciplined approach to capital allocation in support of our commitment to maintain a strong balance sheet. We thoughtfully make capital allocation decisions that we believe will lead to attractive cash returns on investment, including returning capital to our stockholders through quarterly dividends and our share repurchase program as reflected in our current plans to return up to $7.75 billion in capital to common shareholders from November 2021 through 2026. In addition to our dedicated approach to returning value to all stakeholders, we invest prudently in the maintenance of our existing assets and potential growth acquisitions. A strong balance sheet ensures Vistra's interest expense is manageable in a variety of wholesale power price environments while giving Vistra access to flexible and diverse sources of liquidity needed to operate its business and make prudent capital investment decisions. We believe in cost discipline and strong commercial management of our assets and commodity positions to deliver long-term value to our stakeholders, to maintain the safety and reliability of our facilities, all while accelerating growth in our Vistra Zero portfolio pipeline with cost-efficient capital and investment in new technologies when economic, including solar assets and ESS projects, resulting in a continued modernization of Vistra's generation fleet. Integrated business model. Our integrated business model is an important component of our business strategy. This element of our business provides long-term sustainable solutions enabled by our diversified portfolio. This key factor distinguishes us from our electricity competitors by pairing our reliable and efficient mining, diversified generation fleet and wholesale commodity risk management capabilities with our retail platform. Coupling retail with generation is a core competitive advantage that reduces the effects of commodity price movements and contributes to the stability and predictability of our cash flows, a crucial feature of the strategy as Vistra responsibly grows its renewables portfolio and winds down its coal-fueled assets. Superior customer service. Through our retail brands, including TXU Energy, Ambit Energy, Value Based Brands, Dynegy Energy Services, Homefield Energy, TriEagle Energy, Public Power and U.S. Gas Electric, we serve the retail electricity and natural gas needs of end-use residential, small business and commercial and industrial electricity customers through multiple sales and marketing channels. In addition to benefitting from our integrated business model, we leverage our brands, our commitment to safe, reliable and affordable product offerings, our wholesale commodity risk management operations and our strong customer service to differentiate our products and solutions from our competitors. We strive to be at the forefront of innovation with new environmentally-conscious and sustainable-focused product offerings and customer experiences to reinforce our value proposition. We maintain a focus on solutions that provide our customers with choice, convenience and control over how and when they use electricity and related services, including TXU Energy's Free Nights and Solar Days SM residential plans, TXU Energy's Free EV Miles SM residential plans, MyEnergy Dashboard SM , the TXU Energy Green Up SM renewable energy credit program and a diverse set of solar options. Our focus on superior customer service guides our efforts in acquiring new residential and commercial customers, serving and retaining existing customers, and maintaining valuable sales channels for our electricity generation resources. We believe our dependable customer service, innovative products and trusted brands will result in high residential customer retention rates, particularly in Texas where our TXU Energy brand has maintained its residential customers in a highly competitive retail market. Excellence in operations while maintaining an efficient cost structure. We believe delivering long-term stakeholder value is increased as a result of making disciplined investments that enable our generation facilities to operate not only effectively and efficiently, but also safely, reliably and in an environmentally compliant manner as we lead in the clean power transition through the acceleration of our renewables portfolio. We believe that an ongoing focus on operational excellence and safety is a key component to success in a highly competitive environment and is part of the unique value proposition of our integrated model. Additionally, we are committed to optimizing our cost structure, reducing our debt levels, and implementing enterprise-wide process and operating improvements without compromising the safety of our communities, customers and employees. We believe we have a highly effective and efficient cost structure and that our cost structure supports excellence in our operations and is instrumental in our long-term value proposition. Integrated hedging and commercial management. Our commercial team is focused on effectively and efficiently managing risk, through opportunistic hedging, and optimizing our assets and business positions. We proactively manage our exposure to wholesale electricity prices and fuel costs in markets in which we operate, on an integrated basis, through contracts for physical delivery of electricity, exchange-traded and over-the-counter financial contracts, term, day-ahead and real-time market transactions, and bilateral contracts with other wholesale market participants, including other power generators and end-user electricity customers. We actively hedge near-term cash flows and optimize long-term value through hedging and forward sales contracts. We believe our integrated hedging and commercial management strategy, in combination with a strong balance sheet and attractive liquidity profile, will provide long-term advantages through cycles of higher and lower commodity prices. Corporate responsibility and ESG initiatives. It is our purpose to light up people's lives and power a better way forward. We strive to be a good corporate citizen by investing in our employees, putting customers and suppliers first, and improving communities where we live, work and serve as we accelerate toward a clean energy future. Vistra and its employees are actively engaged in programs intended to support our customers and strengthen the communities in which we conduct operations. Our foremost giving initiatives are through the United Way, TXU Energy Aid and Ambit Cares campaigns. TXU Energy Aid serves as an integral resource for social service agencies that assist those in need across Texas pay their electricity bills. Ambit Cares partners with Feeding America to assist those in need across the U.S. by fighting hunger through a network of food banks. Beyond these giving initiatives, Vistra endeavors to consider ESG and all of its stakeholderscustomers, suppliers, local communities, employees, contractors, investors and the environment, among others into our material decisions, processes and activities. The Board has ultimate oversight of our ESG initiatives. We know that prioritizing our stakeholders leads to higher customer satisfaction, more community involvement and support, and committed employees and suppliers, which in turn, leads to a more sustainable company. Our ESG initiatives complement our business strategy and strengthen our resiliency. For instance, our investment in and growth of Vistra Zero supports our long-term goal to achieve net-zero carbon emissions by 2050. We stay informed of evolving ESG standards and remain committed to provide specific and measurable ESG goals and initiatives in a transparent manner. Recent Developments Dividend Declarations In February 2023, the Board declared a quarterly dividend of $0.1975 per share of common stock that will be paid in March 2023 and a semi-annual dividend of $40.00 per share of Series A Preferred Stock that will be paid in April 2023. Market Discussion The operations of Vistra are aligned into six reportable business segments: (i) Retail, (ii) Texas, (iii) East, (iv) West, (v) Sunset and (vi) Asset Closure. The following is a summary of our segments: The Retail segment represents Vistra's retail sales of electricity and natural gas to residential, small business and commercial and industrial customers. The Texas segment represents Vistra's electricity generation operations in the ERCOT market, other than assets that are now part of the Sunset or Asset Closure segments, respectively. The East segment represents Vistra's electricity generation operations in the Eastern Interconnection of the U.S. electric grid, other than assets that are now part of the Sunset or Asset Closure segments, respectively, and includes operations in the PJM, ISO-NE and NYISO markets. The West segment represents Vistra's electricity generation operations in the CAISO market, including our development of battery ESS projects at our Moss Landing power plant site (see Note 2 to the Financial Statements). The Sunset segment represents generation plants with announced retirement dates after December 31, 2022. Separately reporting the Sunset segment differentiates operating plants with announced retirement plans from our other operating plants in the Texas, East and West segments. The Asset Closure segment is engaged in the decommissioning and reclamation of retired plants and mines. The Asset Closure segment also includes results from generation plants we retired in the year ended December 31, 2022. See Note 19 to the Financial Statements for further information concerning reportable segments. Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) Separately, ISOs/RTOs administer the transmission infrastructure and markets across a regional footprint in most of the markets in which we operate. They are responsible for dispatching all generation facilities in their respective footprints and are responsible for both maximum utilization and reliable and efficient operation of the transmission system. ISOs/RTOs administer energy and ancillary service markets in the short term, which usually consists of day-ahead and real-time markets. Several ISOs/RTOs also ensure long-term planning reserves through monthly, semiannual, annual and multi-year capacity markets. The ISOs/RTOs that oversee most of the wholesale power markets in which we operate currently impose, and will likely continue to impose, bid and price limits or other similar mechanisms. NERC regions and ISOs/RTOs often have different geographic footprints, and while there may be geographic overlap between NERC regions and ISOs/RTOs, their respective roles and responsibilities do not generally overlap. In ISO/RTO regions with centrally dispatched market structures (e.g., ERCOT, PJM, ISO-NE, NYISO, MISO, and CAISO), all generators selling into the centralized market receive the same price for energy sold based on the bid price associated with the production of the last MWh that is needed to balance supply with demand within a designated zone or at a given location. Different zones or locations within the same ISO/RTO may produce different prices respective to other zones or locations within the same ISO/RTO due to transmission losses and congestion. For example, a less efficient and/or less economical natural gas-fueled unit may be needed in some hours to meet demand. If this unit's production is required to meet demand on the margin, its offer price will set the market clearing price for all dispatched generation in the same market (although the price paid at other zones or locations may vary because of transmission losses and congestion), regardless of the price that any other unit may have offered into the market. Generators will receive the location-based marginal price for their output. Retail Segment The Retail segment is engaged in retail sales of electricity, natural gas and related services to approximately 3.5 million customers. Substantially all of these activities are conducted by TXU Energy, Ambit Energy, Value Based Brands, Dynegy Energy Services, Homefield Energy, TriEagle Energy, Public Power and U.S. Gas Electric across 19 U.S. states and the District of Columbia. The largest portion of our retail operations are in Texas, where we provide retail electricity to approximately 2.4 million customers in ERCOT. We are an active participant in the competitive ERCOT retail market and continue to be a market leader, which we believe is driven by, among other things, strong brands, innovative products and services and excellent customer service. As of December 31, 2022, we provided electricity to approximately 30% of the residential customers in ERCOT and for approximately 16% of business customers' demand. We believe that we have differentiated ourselves by providing a distinctive customer experience predicated on delivering reliable and innovative power products and solutions to our customers, which give our customers choice, convenience and control over how and when they use electricity and related services. Our retail business also offers a comprehensive suite of green products and services, including 100% wind and solar options, as well as thermostats, dashboards and other programs designed to encourage reduced consumption and increased energy efficiency. Our integrated power generation and wholesale operation allows us to efficiently obtain the electricity needed to serve our customers at the lowest cost. The integrated model enables us to structure products and contracts in a way that offers significant value compared to stand-alone retail electric providers. Additionally, our wholesale commodity risk management operations help increase the profitability of our retail business by allowing us to bypass bid-ask spread in the market (particularly for illiquid products and time periods) and achieve lower collateral costs as compared to other, non-integrated retail electric providers. Moreover, our retail business can reduce, to some extent, the exposure of our wholesale generation business to wholesale power price volatility. This is because the retail load requirements of our retail operations can provide a natural offtake to the length of Luminant's generation portfolio when economic, thereby reducing the exposure to wholesale power price volatility as compared to a non-integrated independent power producer. Outside of ERCOT, we also serve residential, municipal, commercial and industrial customers substantially through our Homefield Energy, Dynegy Energy Services, Public Power, U.S. Gas Electric and Ambit Energy retail businesses, through which we provide retail electricity, natural gas and related services to approximately 1.1 million customers in 18 states and the District of Columbia. Texas Segment Our Texas segment is comprised of 21 power generation facilities totaling 18,141 MW of generation capacity in ERCOT. ##TABLE_START ISO/RTO Technology Primary Fuel Number of Facilities Net Capacity (MW) ERCOT CCGT Natural Gas 7 7,838 ERCOT ST Coal 2 3,850 ERCOT CT or ST Natural Gas 7 3,455 ERCOT Nuclear Nuclear 1 2,400 ERCOT Solar/Battery Renewable 4 598 Total Texas Segment 21 18,141 ##TABLE_ENDWe have announced the potential for additional development of solar photovoltaic power generation facilities and battery ESS in Texas, with estimated commercial operation dates for these facilities beginning in 2024. See Note 2 to the Financial Statements for a summary of our solar and battery energy storage projects. ERCOT ERCOT is an ISO that manages the flow of electricity from approximately 98,000 MW of expected Summer 2023 peak generation capacity to approximately 26 million Texas customers, representing approximately 90% of the state's electric load. As an energy-only market, ERCOT's market design is distinct from other competitive electricity markets in the U.S. Other markets maintain a minimum planning reserve margin through regulated planning, resource adequacy requirements and/or capacity markets. In contrast, ERCOT's resource adequacy is currently predominately dependent on energy-market price signals. The PUCT recently voted to recommend a Performance Credit Mechanism (PCM) that would align a required reliability standard with resource availability during higher-risk system conditions in a centrally-cleared market. These changes are currently being evaluated by the PUCT and the Texas legislature and have not been implemented as of the date hereof. In 2014, ERCOT implemented the Operating Reserve Demand Curve (ORDC), pursuant to which wholesale electricity prices in the real-time electricity market increase automatically as available operating reserves decrease below defined threshold levels, creating a price adder. The slope of the ORDC curve is determined through a mathematical loss of load probability calculation using forecasted reserves and historical data. In both March 2019 and March 2020, ERCOT implemented 0.25 standard deviation shifts in the loss of load probability calculation and moved to using a single blended ORDC curve; these changes resulted in a more rapid escalation in power prices as operating reserves fall below defined thresholds. Effective January 1, 2022, when operating reserves drop to

3,000 MW or less, the ORDC automatically adjusts power prices to the established value of lost load (VOLL), which is set at $5,000/MWh which is equal to the high system-wide offer cap. ERCOT also calculates the "peaker net margin" based on revenues a hypothetical unhedged peaking unit would collect in the market. If the peaker net margin exceeds a certain threshold, the system-wide offer cap is reduced to the low system-wide offer cap of $2,000/MWh for the remainder of the calendar year. Historically, high demand due to elevated temperatures in the summer months or high demand due to reduced temperatures in the winter months, combined with underperformance of wind generation, has created the conditions during which the ORDC contributes meaningfully to power prices. Extreme weather conditions can also lead to scarcity conditions regardless of season. Other than during periods of "scarcity pricing," the price of power is typically set by natural gas-fueled generation facilities (see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Key Operational Risks and Challenges). Transactions in ERCOT take place in two key markets: the day-ahead market and the real-time market. The day-ahead market is a voluntary, financial electricity market conducted the day before each operating day in which generators and purchasers of electricity may bid for one or more hours of electricity supply or consumption. The real-time market is a physical market in which electricity is dispatched and priced in five-minute intervals. The day-ahead market provides market participants with visibility into where prices are expected to clear, and the prices are not impacted by subsequent events. Conversely, the real-time market exposes purchasers to the risk of transient operational events and price spikes. These two markets allow market participants to manage their risk profile by adjusting their participation in each market. In addition, ERCOT uses ancillary services to maintain system reliability, including regulation service, responsive reserve service and non-spinning reserve service. Ancillary services are provided by generators and qualified loads to help maintain the stable voltage and frequency requirements of the transmission system. Because ERCOT has one of the highest concentrations of wind and solar capacity generation among U.S. markets, the ERCOT market is more susceptible to fluctuations in wholesale electricity supply due to intermittent wind and solar production, making ERCOT more vulnerable to periods of generation scarcity. Beginning in July 2021, ERCOT has increased its ancillary service procurement volumes to maintain a more conservative level of operating reserves. East Segment Our East segment is comprised of 21 power generation facilities in 10 states totaling 12,093 MW of generating capacity in PJM, ISO-NE and NYISO. ##TABLE_START ISO/RTO Technology Primary Fuel Number of Facilities Net Capacity (MW) PJM CCGT Natural Gas 8 6,081 PJM CT Natural Gas 4 1,346 PJM CT Fuel Oil 2 93 ISO-NE CCGT Natural Gas 6 3,361 NYISO CCGT Natural Gas 1 1,212 Total East Segment 21 12,093 ##TABLE_ENDWe plan to develop up to 300 MW of solar photovoltaic power generation facilities and up to 150 MW of battery ESS at retired or to-be-retired plant sites in Illinois with estimated commercial operation dates for these facilities ranging from 2024 to 2025. See Note 2 to the Financial Statements for a summary of our solar and battery energy storage projects. PJM PJM is an RTO that manages the flow of electricity from approximately 185,000 MW of generation capacity to approximately 65 million customers in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. Like ERCOT, PJM administers markets for wholesale electricity and provides transmission planning for the region, utilizing a locational marginal pricing (LMP) methodology which calculates a price for every generator and load point within PJM. PJM operates day-ahead and real-time markets into which generators can bid to provide energy and ancillary services. PJM also administers a forward capacity auction, the Reliability Pricing Model (RPM), which establishes a long-term market for capacity. We have participated in RPM auctions for years up to and including PJM's planning year 2024-2025, which ends May 31, 2025. We also enter into bilateral capacity transactions. PJM's Capacity Performance (CP) rules were designed to improve system reliability and include penalties for under-performing units and reward for over-performing units during shortage events. Full transition of the capacity market to CP rules occurred in planning year 2020-2021. An independent market monitor continually monitors PJM markets to ensure a robust, competitive market and to identify improper behavior by any entity. ISO-NE ISO-NE is an ISO that manages the flow of electricity from approximately 32,600 MW of winter generation capacity to approximately 15 million customers in the states of Vermont, New Hampshire, Massachusetts, Connecticut, Rhode Island and Maine. ISO-NE dispatches power plants to meet system energy and reliability needs and settles physical power deliveries at LMPs. Its energy markets allow market participants to buy and sell energy and ancillary services at prices established through real-time and day-ahead auctions. Energy prices vary among the locations in ISO-NE and are largely influenced by transmission constraints and fuel supply. ISO-NE offers a forward capacity market where capacity prices are determined through auctions. Performance incentive rules have the potential to increase capacity payments for those resources that are providing excess energy or reserves during a shortage event, while penalizing those that produce less than the required level. NYISO NYISO is an ISO that manages the flow of electricity from approximately 37,500 MW of installed summer generation capacity to approximately 20 million New York customers. NYISO dispatches power plants to meet system energy and reliability needs and settles physical power deliveries at LMPs. Its energy markets allow market participants to buy and sell energy and ancillary services at prices established through real-time and day-ahead auctions. Energy prices vary among the regional zones and locations in the NYISO and are largely influenced by transmission constraints and fuel supply. NYISO offers a forward capacity market where capacity prices are determined through auctions. Strip auctions occur one to two months prior to the commencement of a six-month seasonal planning period. Subsequent auctions provide an opportunity to sell excess capacity for the balance of the seasonal planning period or the upcoming month. Due to the short-term nature of the NYISO-operated capacity auctions and a relatively liquid bilateral market for NYISO capacity products, our Independence facility sells a significant portion of its capacity through bilateral transactions. The balance is cleared through the seasonal and monthly capacity auctions. West Segment Our West segment is comprised of two power generation facilities totaling 1,130 MW of generation capacity and the first two phases of a battery ESS facility totaling 400 MW in CAISO, all of which are located in California. ##TABLE_START ISO/RTO Technology Primary Fuel Number of Facilities Net Capacity (MW) CAISO CCGT Natural Gas 1 1,020 CAISO Battery Renewable 1 400 CAISO CT Fuel Oil 1 110 Total West Segment 3 1,530 ##TABLE_ENDWe plan to develop an additional 350 MW in the third phase of our battery ESS at our Moss Landing Power Plant site with an estimated commercial operation date in the summer of 2023. CAISO CAISO is an ISO that manages the flow of electricity to approximately 32 million customers primarily in California, representing approximately 80% percent of the state's electric load. Energy is priced in CAISO utilizing an LMP methodology. The capacity market is comprised of Generic, Flexible and Local Resource Adequacy (RA) Capacity and is administered by the California Public Utilities Commission (CPUC). Unlike other centrally cleared capacity markets, the resource adequacy markets in California are primarily bilaterally traded markets. In 2020, the CPUC introduced a central procurement entity for Local RA Capacity effective for the 2023 compliance year. The central procurement entity runs a pay-as-bid auction for Local RA Capacity. In November 2016, CAISO implemented a voluntary capacity auction for annual, monthly, and intra-month procurement to cover for deficiencies in the market. The voluntary Competitive Solicitation Process, which FERC approved in October 2015, is a modification to the Capacity Procurement Mechanism (CPM) and provides another avenue to sell RA capacity. Sunset Segment Our Sunset segment is comprised of six power generation facilities totaling 5,163 MW of generating capacity in MISO, PJM and ERCOT. The Sunset segment represents plants with announced retirement plans between 2022 and 2027 that were previously reported in the ERCOT, PJM and MISO segments. See Note 3 to the Financial Statements for more information related to these planned generation retirements. ##TABLE_START ISO/RTO Technology Primary Fuel Number of Facilities Net Capacity (MW) ERCOT ST Coal 1 650 MISO (a) ST Coal 3 2,385 PJM ST Coal 2 2,128 Total Sunset Segment 6 5,163 ##TABLE_END____________ (a) Includes the 585 MW Edwards facility that was retired on January 1, 2023. See Texas Segment above for a discussion of the ERCOT ISO and East Segment above for a discussion of the PJM RTO. MISO MISO is an RTO that manages the flow of electricity from approximately 190,000 MW of installed generation capacity to approximately 45 million customers in all or parts of Iowa, Minnesota, North Dakota, Wisconsin, Michigan, Kentucky, Indiana, Illinois, Missouri, Arkansas, Mississippi, Texas, Louisiana, Montana, South Dakota and Manitoba, Canada. MISO dispatches power plants to meet system energy and reliability needs and settles physical power deliveries at LMPs. Its energy markets allow market participants to buy and sell energy and ancillary services at prices established through real-time and day-ahead auctions. Energy prices vary among the regional zones and locations in

MISO and are largely influenced by transmission constraints and fuel supply. An independent market monitor is responsible for evaluating the performance of the markets and identifying conduct by market participants or MISO that may compromise the efficiency or distort the outcome of the markets. MISO administers a one-year Planning Resource Auction for the next planning year from June 1st of the current year to May 31st of the following year. In 2022, FERC approved MISO's proposal to change the annual Planning Resource Auction into a seasonal auction, effective for the 2023-2024 planning year. We participate in these auctions with open capacity that has not been committed through bilateral or retail transactions. We also participate in the MISO annual and monthly financial transmission rights auctions to manage the cost of our transmission congestion, as measured by the congestion component of the LMP price differential between two points on the transmission grid across the market area. Wholesale Operations Our wholesale commodity risk management group is responsible for dispatching our generation fleet in response to market needs after implementing portfolio optimization strategies, thus linking and integrating the generation fleet production with our retail customer and wholesale sales opportunities. Market demand, also known as load, faced by electric power systems, such as those we operate in, varies from moment to moment as a result of changes in business and residential demand, which is often driven by weather. Unlike most other commodities, the production and consumption of electricity must remain balanced on an instantaneous basis. There is a certain baseline demand for electricity across an electric power system that occurs throughout the day, which is typically satisfied by baseload generating units with low variable operating costs. Baseload generating units can also increase output to satisfy certain incremental demand and reduce output when demand is unusually low. Intermediate/load-following generating units, which can more efficiently change their output to satisfy increases in demand, typically satisfy a large proportion of changes in intraday load as they respond to daily increases in demand or unexpected changes in supply created by reduced generation from renewable resources or other generator outages. Peak daily loads may be satisfied by peaking units. Peaking units are typically the most expensive to operate, but they can quickly start up and shut down to meet brief peaks in demand. In general, baseload units, intermediate/load following units and peaking units are dispatched into the ISO/RTO grid in order from lowest to highest variable cost. Price formation is typically based on the highest variable cost unit that clears the market to satisfy system demand at a given point in time. Our commodity risk management group also enters into electricity, gas and other commodity derivative contracts to reduce exposure to changes in prices primarily to hedge future revenues and fuel costs for our generation facilities and purchased power costs for our Retail segment. Seasonality The demand for and market prices of electricity and natural gas are affected by weather. As a result, our operating results are impacted by extreme or sustained weather conditions and may fluctuate on a seasonal basis. Typically, demand for and the price of electricity is higher in the summer and winter seasons, when the temperatures are more extreme, and the demand for and price of natural gas is also generally higher in the winter. More severe weather conditions such as heat waves or extreme winter weather have made, and may make, such fluctuations more pronounced. The pattern of this fluctuation may change depending on, among other things, the retail load served and the terms of contracts to purchase or sell electricity. Competition Competition in the markets in which we operate is impacted by electricity and fuel prices, congestion along the power grid, subsidies provided by state and federal governments for new and existing generation facilities, including renewables generation and battery ESS, new market entrants, construction of new generating assets, technological advances in power generation, the actions of environmental and other regulatory authorities, and other factors. We primarily compete with other electricity generators and retailers based on our ability to generate electric supply, market and sell electricity at competitive prices and to efficiently utilize transportation from third-party pipelines and transmission from electric utilities to deliver electricity to end-users. Competitors in the generation and retail power markets in which we participate include numerous regulated utilities, industrial companies, non-utility generators, competitive subsidiaries of regulated utilities, independent power producers, REPs and other energy marketers. See Item 1A. Risk Factors for additional information concerning the risks faced with respect to the markets in which we operate. Brand Value Our TXU Energy brand, which has been used to sell electricity to customers in the competitive retail electricity market in Texas for approximately 20 years, is registered and protected by trademark law and is the only material intellectual property asset that we own. We have also acquired the trade names for Ambit Energy, Dynegy Energy Services, Homefield Energy, TriEagle Energy, Public Power and U.S. Gas Electric through the Ambit Transaction, Crius Transaction and the Merger, as the case may be. As of December 31, 2022, we have reflected intangible assets on our balance sheet for our trade names of approximately $1.341 billion (see Note 5 to the Financial Statements). Human Capital Resources As a key component of our core principle that we work as a team , Vistra believes our most valuable asset is our talented, dedicated and diverse group of employees who work together to achieve our objectives, and our top priority is ensuring their safety. One of Vistra's core principles is that we care about our key stakeholders , including our employees. We invest in our people through numerous development and training opportunities, engaging employee programs and generous benefit and wellness offerings. As of December 31, 2022, we had approximately 4,910 full-time employees, including approximately 1,295 employees under collective bargaining agreements. Safety Vistra's mindset around safety is exemplified by our motto: Best Defense. Everyone wins. No one gets hurt. Our safety culture revolves around people and human performance. We place a high importance on continuous improvement, along with a keen focus on numerous learning and error-prevention tools. To facilitate a learning environment, our various operating plants share their investigations and learnings of all safety events with all operations employees on weekly calls. The information is presented by front-line employees and supported by management. The lessons from each event are shared across the fleet to prevent similar incidents at other locations. All personnel at Vistra locations are encouraged to be actively involved in the safety process. Managers are required to participate in safety engagements with staff to enable constant communication and sustained interaction. In 2022, the generation fleet conducted more than 52,000 leadership safety engagements across the fleet continuing our employee driven safety program focused on engagement of all employees. Our focus on reducing the severity of injuries for both our employees and contractors who work with us has shown positive results. In 2022, we did not have any serious injuries, as determined in accordance with industry standards, or fatalities to our Vistra employees or business partners working at our sites. Although we do not focus on recordable incidents, our Total Recordable Incident rate (TRIR) for the company was 0.85, in the second quartile as compared to the Edison Electric Institute (EEI) 2021 Total Company Injury Data. We encourage near-miss reporting and review of events to promote a learning environment. In 2022, safety learning calls were held every week where 128 near-miss and safety events were reviewed by our operating teams to promote learning across the fleet. All Vistra employees are covered by our safety program. Corporate and retail employees are required to complete periodic training on safety topics through our online learning management system. Employees who are located at a power plant are required to complete trainings based on job function, which is also tracked through our central learning management system. In addition, the Company engages an independent third-party conformity assessment and certification vendor to manage adherence to our safety standards for all vendors and contractors who work at our plants. In addition, we work closely with our suppliers and contractors to ensure our safety practices are upheld. All of our power plant facilities have effective health and safety programs and comply with OSHA regulations. In addition to compliance, our generation fleet has a total of 14 plants that have been awarded the Voluntary Protection Program (VPP) Star designation by the OSHA for superior demonstration of effective safety and health management systems and for maintaining injury and illness rates below the national averages for our industry. Two additional plants have submitted applications and are awaiting review by the OSHA. VPP Star status is the highest designation of OSHA's Voluntary Protection Programs. The achievement recognizes employers and workers who have implemented effective safety and health management systems and maintain injury and illness rates below national Bureau of Labor Statistics averages for their respective industries. These sites are self-sufficient in their ability to control workplace hazards and are reevaluated every three to five years. Additionally, 32 of our power plants and mine locations have adopted a proactive Behavior Based Safety approach to safety which focuses on identifying and providing feedback on at-risk behaviors observed. In 2022, we continued our COVID-19 protections and protocols helping to ensure the safety of all of our employees. Diversity, Equity and Inclusion We recognize the value of having a diverse and inclusive workforce. Our diversity includes all the ways we differ, such as age, gender, ethnicity and physical appearance, as well as underlying differences such as thoughts, styles, religions, nationality, education and numerous other traits. Creating and maintaining an environment where differences are valued and respected enhances our ability to recruit and retain the best talent in the marketplace and to provide a work environment that allows all employees to be their best. Vistra's diversity is evolving, and our Board and management are leading by example. Currently, four of the eleven Board members are women, and two of the eleven are ethnically diverse. Overall, 32% of the Company's workforce is ethnically diverse. Women currently hold 25% of the Company's senior management positions, and ethnically diverse employees represent 27% of senior management. During 2022, we continued our efforts to unlock the full potential of our people by launching multiple new initiatives within our diversity, equity, and inclusion efforts. Our Chief Diversity Officer continued to develop and lead Vistra's employee-led Diversity, Equity and Inclusion Advisory Council, established in 2020. In 2022, the council expanded its role and participated directly in the development of new diversity training modules, the launching of Vistra's 2022 Employee Engagement Survey and the launch of a new learning platform. We continued to utilize our thirteen Employee Resource Groups (ERGs) to promote the appreciation of and communicate awareness of diverse employee groups and communities and their contribution to the overall success of the organization, both internally and externally. ERGs represent not only diverse cultures, but also employees with disabilities, the LGBTQ+ community and employees engaged in innovation. Further initiatives were launched to support the education, recruitment and retention of current and future employees, with particular emphasis being placed on driving equal access to opportunities throughout the organization. The emphasis on skills based hiring continued in 2022. People managers across the organization also participated in one-day and two-day training sessions conducted by Basic Diversity, Inc. Vistra is active in our communities to promote inclusivity. Vistra's supply chain diversity initiative seeks to reflect our customer base and workforce compositions through creating a diverse supply chain. Vistra continued to expand its commitment to an inclusive economy by fostering mentorship of diverse businesses. Further, in the third year of Vistra's $10 million five-year commitment to support underserved communities, Vistra provided funding to educational and economic development nonprofits around the country working to transform underserved communities for the better. Training and Development We believe the development of employees at all levels is critical to Vistra's current and future success. We have launched key programs to develop leaders at all levels of the organization. Vistra's Essentials in Leadership provides first time managers with skills to lead organizations in situational leadership, business acumen, identification of communication styles and inclusive communication practices, and exposes them to best practices from across the company. We also reinstated in-person leadership development classes and continued to provide virtual opportunities. In 2022, Vistra added an emotional intelligence program that was well received by leaders across the organization. Vistra also provides many other training and development programs to help grow and develop employees at every level, including online learning platform courses, learning management system courses, recorded webinars and presentations, self-paced development and employee-specific skill training. The launch of the new and improved online learning platform in 2022 further supports employees in completing thousands of hours of professional training to support continuing education requirements for their respective professional licenses, including accounting, legal and nuclear. In 2022, Vistra continued its formal mentoring program available to all employees to focus on topics like organizational knowledge, career development, individual development, collaboration and leadership. Over 600 employees participated in 2022. In addition, all full-time employees, other than those in a collective bargaining unit, receive a formal performance review guiding development and improving results of the business. Employee Benefits Maintaining attractive benefits and pay are important for recruiting and retaining talent. We are committed to maintaining an equitable compensation structure, including performing annual salary reviews by employee category level within significant locations of operations. Eligible full- and part-time employees are provided access to medical, prescription drug, dental, vision, life insurance, accidental death and dismemberment, long-term disability coverage, accident coverage, critical illness coverage and hospital indemnity coverage. Regular full-time employees are eligible for short-term disability benefits, and all employees are eligible for the employee assistance program, parental leave, maternity leave and a 401(k) plan through which the Company matches employee contributions up to 6%. Wellness We believe a healthy workforce leads to greater well-being at work and at home. To help keep our workforce healthy, we offer access to on-site medical clinics at six locations. Our healthcare plans are also designed to reward employees for getting annual physicals, age and gender health screenings and immunizations. In addition, our employee medical plans promote mental health and emotional wellness and offer resources for employees seeking assistance. Fitness centers in multiple facilities offer cardio equipment, a selection of free weights and exercise mats. Our employee-led wellness team engages our people to get active and support causes that promote healthy living. With support from the company, the wellness team covers the registration costs for employees to participate in running and cycling events throughout the year. Environmental Regulations and Related Considerations We are subject to extensive environmental regulation by governmental authorities, including the EPA and the environmental regulatory bodies of states in which we operate. The EPA has finalized or proposed several regulatory actions establishing new requirements for control of certain emissions from sources, including electricity generation facilities. See Item 1A. Risk Factors for additional discussion of risks posed to us regarding regulatory requirements. See Note 12 to the Financial Statements for a discussion of litigation related to EPA reviews. Climate Change There is continuing attention and interest domestically and internationally about global climate change and how GHG emissions, such as CO_2 , contribute to global climate change. GHG emissions from the combustion of fossil fuels, primarily by our coal-fueled-generation plants as well as our natural gas-fueled generation plants represent the substantial majority of our total GHG emissions. CO_2 , methane and nitrous oxide are emitted in this combustion process, with CO_2

representing the largest portion of these GHG emissions. We estimate that our generation facilities produced approximately 104 million short tons of CO_2 in the year ended 2022. To manage our environmental impact from our business activities and reduce our emissions profile, Vistra set emissions reduction targets. Vistra is targeting to achieve a 60% reduction in Scope 1 and Scope 2 CO_2 equivalent emissions by 2030 as compared to a 2010 baseline with a long-term goal to achieve net-zero carbon emissions by 2050, assuming necessary advancements in technology and supportive market constructs and public policy. In furtherance of Vistra's efforts to meet its net-zero target, Vistra expects to deploy multiple levers to transition the company to operating with net-zero emissions, including decarbonization of existing business lines and further diversification into low-to-no emission businesses, primarily renewables and energy storage. We have already taken or announced significant steps to transform our generation portfolio and reduce the emissions intensity of our generation fleet, including: Solar Projects We operate solar generations facilities totaling 338 MW in Texas. We have announced our plans to develop: additional solar generation facilities in Texas, with expected commercial operation dates beginning in 2024, and 300 MW of solar generation facilities at retired or to-be retired plant sites in Illinois with expected commercial operation dates ranging from 2024 to 2025. Battery Energy Storage Projects We operate battery ESSs totaling 270 MW in Texas and 400 MW in California. We have announced our plans to develop: 150 MW of battery ESS at retired or to-be-retired plant sites in Illinois with expected commercial operation dates ranging from 2024 to 2025, and 350 MW of battery ESS in California with an expected commercial operation date in 2023. Acquisition of CCGTs In 2016 and 2017, we acquired 4,042 MW of CCGTs in Texas. In 2018, we acquired 15,448 MW of CCGTs across various ISOs/RTOs in connection with the Merger. Retirements of Fossil Fuel Generation Since 2018, lignite/coal-fueled generation facilities retired include 4,167 MW in Texas, 3,455 MW in Illinois (including the Edwards facility that was retired on January 1, 2023) and 1,300 MW in Ohio. We expect to retire an additional 4,578 MW of coal-fueled generation facilities in Illinois, Ohio and Texas no later than year-end 2027. See Note 2 to the Financial Statements for discussion of our solar and battery ESS projects and Note 3 to the Financial Statements for discussion of our retirement of generation facilities. GHG Emissions In July 2019, the EPA finalized a rule that repealed the Clean Power Plan (CPP) that had been finalized in 2015 and established new regulations addressing GHG emissions from existing coal-fueled electric generation units, referred to as the Affordable Clean Energy (ACE) rule. The ACE rule developed emission guidelines that states must use when developing plans to regulate GHG emissions from existing coal-fueled electric generating units. In response to challenges brought by environmental groups and certain states, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court) vacated the ACE rule, including the repeal of the CPP, in January 2021 and remanded the rule to the EPA for further action. In June 2022, the U.S. Supreme Court issued an opinion reversing the D.C. Circuit Court's decision, and finding that the EPA exceeded its authority under Section 111 of the Clean Air Act when the EPA set emission requirements in the CPP based on generation shifting. In October 2022, the D.C. Circuit Court issued an amended judgment, denying petitions for review of the ACE rule and challenges to the repeal of the CPP. In addition, the EPA has opened a docket seeking input on questions related to the regulation of GHGs under Section 111(d) and has indicated its intent to issue a new proposal in Spring 2023. State Regulation of GHGs Many states where we operate generation facilities have, are considering, or are in some stage of implementing, state-only regulatory programs intended to reduce emissions of GHGs from stationary sources as a means of addressing climate change. Regional Greenhouse Gas Initiative (RGGI) RGGI is a state-driven GHG emission control program that took effect in 2009 and was initially implemented by ten New England and Mid-Atlantic states to reduce CO_2 emissions from power plants. The participating RGGI states implemented a cap-and-trade program. Compliance with RGGI can be achieved by reducing emissions, purchasing or trading allowances, or securing offset allowances from an approved offset project. We are required to hold allowances equal to at least 50 percent of emissions in each of the first two years of the three-year control period. In December 2017, the RGGI states released an updated model rule with changes to the CO_2 budget trading program, including an additional 30 percent reduction in the CO_2 annual cap by the year 2030, relative to 2020 levels. RGGI is currently conducting its third program review to be completed by the end of 2023 which may include an updated model rule. Our generating facilities in Connecticut, Maine, Massachusetts, New Jersey, New York and Virginia emitted approximately 9 million tons of CO_2 during 2022. The spot market price of RGGI allowances required to operate these facilities as of December 31, 2022 was approximately $13.57 per allowance. The spot market price of RGGI allowances required to operate our affected facilities during 2023 was approximately $12.63 per allowance on February 23, 2023. While the cost of allowances required to operate our RGGI-affected facilities is expected to increase in future years, we expect that the cost of compliance would be reflected in the power market, and the actual impact to gross margin would be largely offset by an increase in revenue. Massachusetts In August 2017, the Massachusetts Department of Environmental Protection (MassDEP) adopted final rules establishing an annual declining limit on aggregate CO_2 emissions from 21 in-state fossil-fueled electricity generation units. The rules establish an allowance trading system under which the annual aggregate electricity generation unit sector cap on CO_2 emissions declines from 8.96 million metric tons in 2018 to 1.8 million metric tons in 2050. MassDEP allocated emission allowances to affected facilities for 2018. Beginning in 2019, the allocation process transitioned to a competitive auction process whereby allowances are partially distributed through a competitive auction process and partially distributed based on the process and schedule established by the rule. Beginning in 2021, all allowances were distributed through the auction. Limited banking of unused allowances is allowed. Virginia In May 2019, the Virginia Department of Environmental Quality issued a final rule to adopt a carbon cap-and trade program for fossil-fueled electricity generation units, including our Hopewell facility, beginning in

2020. The program is based on the RGGI proposed 2017 model rule and linked Virginia to RGGI in 2021. The Governor of Virginia issued an executive order in January 2022 to begin the process of removing the state from RGGI; however, the Virginia General Assembly would need to modify the law to exit the program. At this time, no new laws have passed and Virginia remains in RGGI. New Jersey In January 2018, the Governor of New Jersey signed an executive order directing the state's environmental agency and public utilities board to begin the process of rejoining RGGI, and New Jersey formally rejoined RGGI in June 2019. In June 2019, New Jersey adopted two rules that govern New Jersey's reentry into the RGGI auction and distribution of the RGGI auction proceeds. Pennsylvania In April 2022, the Pennsylvania Environmental Quality Board finalized regulations that would establish Pennsylvania's participation in RGGI. In July 2022, the Commonwealth Court took action to uphold a preliminary injunction over Pennsylvania's RGGI regulations. The Pennsylvania Supreme Court denied a request for emergency relief from the injunction in August 2022 and review of the legality of the injunction is now pending before the Pennsylvania Supreme Court. As a result, RGGI is not being implemented or enforced in Pennsylvania at this time. California Our assets in California are subject to the California Global Warming Solutions Act, which required the California Air Resources Board (CARB) to develop a GHG emission control program to reduce emissions of GHGs in the state to 1990 levels by 2020. In April 2015, the Governor of California issued an executive order establishing a new statewide GHG reduction target of 40 percent below 1990 levels by 2030 to ensure California meets its 2050 GHG reduction target of 80 percent below 1990 levels. We have participated in quarterly auctions or in secondary markets, as appropriate, to secure allowances for our affected assets. In July 2017, California enacted legislation extending its GHG cap-and-trade program through 2030 and the CARB adopted amendments to its cap-and-trade regulations that, among other things, established a framework for extending the program beyond 2020 and linking the program to the new cap-and-trade program in Ontario, Canada beginning in January 2018. Air Emissions The Clean Air Act (CAA) The CAA and comparable state laws and regulations relating to air emissions impose various responsibilities on owners and operators of sources of air emissions, which include requirements to obtain construction and operating permits, pay permit fees, monitor emissions, submit reports and compliance certifications, and keep records. The CAA requires that fossil-fueled electricity generation plants meet certain pollutant emission standards and have sufficient emission allowances to cover SO_2 emissions and in some regions NO_X emissions. In order to ensure continued compliance with the CAA and related rules and regulations, we utilize various emission reduction technologies. These technologies include flue gas desulfurization (FGD) systems, dry sorbent injection (DSI), baghouses and activated carbon injection or mercury oxidation systems on select units and electrostatic precipitators, selective catalytic reduction (SCR) systems, low-NO_X burners and/or overfire air systems on all units. Cross-State Air Pollution Rule (CSAPR) In 2016, the EPA finalized the Cross-State Air Pollution Rule Update (CSAPR Update) to address 22 states' obligations with respect to the 2008 ozone National Ambient Air Quality Standards (NAAQS). In 2019, following challenges by numerous parties, the D.C. Circuit Court found that the CSAPR Update did not fully address certain states' 2008 ozone NAAQS obligations. In October 2020, the EPA proposed an action to address the outstanding 2008 ozone NAAQS obligations in response to the D.C. Circuit Court's 2019 ruling. Vistra subsidiaries filed comments on that rulemaking in December 2020, and the EPA published a final rule in the Federal Register on April 30, 2021 that reduces ozone season NO X budgets in certain states. We do not believe that the final rule causes a material adverse impact on our future financial results. In October 2015, the EPA revised the primary and secondary ozone NAAQS to lower the 8-hour standard for ozone emissions during ozone season (May to September). As required under the CAA, in October 2018, the State of Texas submitted a State Implementation Plan (SIP) to the EPA demonstrating that emissions from Texas sources do not contribute significantly to nonattainment in, or interfere with maintenance by, any other state with respect to the revised ozone NAAQS. In February 2023, the EPA disapproved Texas's SIP. In April 2022, prior to the EPA's disapproval of Texas's SIP, the EPA proposed a Federal Implementation Plan (FIP) to address the 2015 ozone NAAQS. The proposed FIP would apply to 25 states beginning with the 2023 ozone seasons. States where Vistra operates generation units that would be subject to this proposed rule are Illinois, New Jersey, New York, Ohio, Pennsylvania, Texas, Virginia and West Virginia. The revised Group 3 trading program (previously established in the Revised CSAPR Update Rule) would include emission budgets for 2023 that the EPA says are achievable through existing controls installed at power plants. Starting in 2026, the budgets would be based on levels achieved through installation of SCR controls at the approximately 20% of large coal-fueled power plants that do not currently have such controls. Starting in 2025, the budgets would be updated annually to account for source retirements. Starting in 2024, the rule would also impose a daily emissions rate limit for coal-fueled units with existing controls and would impose such a limit for units installing new controls in 2027. We, along with many other companies, trade groups, states and ISOs, including ERCOT, PJM and MISO, filed responsive comments to the EPA's proposal in June 2022, expressing concerns about certain elements of the proposal, particularly those that may result in challenges to electric reliability under certain conditions. The EPA is expected to finalize the proposed FIP in March 2023. In February 2022, the State of Texas, Luminant, certain trade groups, and others filed legal challenges to the EPA's disapproval of Texas's SIP in the U.S. Court of Appeals for the Fifth Circuit (Fifth Circuit Court). If the EPA finalizes the FIP described above as expected in March 2023, it will impose reduced ozone season NO X budgets under the CSAPR program for our Texas power plants. We cannot predict the outcome of our legal challenges to the EPA's disapproval of the SIP, any legal action related to the EPA's FIP once finalized, or the effects of the final rule (after the conclusion of legal challenges) on operations of our generation fleet. Regional Haze Reasonable Progress and Best Available Retrofit Technology (BART) for Texas The Regional Haze Program of the CAA establishes "as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I federal areas which impairment results from man-made pollution." There are two components to the Regional Haze Program. First, states must establish goals for reasonable progress for Class I federal areas within the state and establish long-term strategies to reach those goals and to assist Class I federal areas in neighboring states to achieve reasonable progress set by those states towards a goal of natural visibility by 2064. Second, certain electricity generation units built between 1962 and 1977 are subject to BART standards designed to improve visibility if such units cause or contribute to impairment of visibility in a federal class I area. In October 2017, the EPA issued a final rule addressing BART for Texas electricity generation units, with the rule serving as a partial approval of Texas' 2009 SIP and a partial FIP. For SO_2 , the rule established an intrastate Texas emission allowance trading program as a "BART alternative" that operates in a similar fashion to a CSAPR trading program. The program includes 39 generating units (including the Martin Lake, Big Brown, Monticello, Sandow 4, Coleto Creek, Stryker 2 and Graham 2 plants). The compliance obligations in the program started on January 1, 2019. For NO_X , the rule adopted the CSAPR's ozone program as BART and for particulate matter, the rule approved Texas' SIP that determines that no electricity generation units are subject to BART for particulate matter. In August 2020, the EPA issued a final rule affirming the prior BART final rule but also included additional revisions that were proposed in November 2019. Challenges to both the 2017 rule and the 2020 rules have been consolidated in the D.C. Circuit Court, where we have intervened in support of the EPA. We are in compliance with the rule, and the retirements of our Monticello, Big Brown and Sandow 4 plants have enhanced our ability to comply. The EPA has stated it is starting a proceeding for reconsideration of the BART rule, which we expect in 2023. The challenges in the D.C. Circuit Court have been held in abeyance pending the EPA's action on reconsideration. National Ambient Air Quality Standards (NAAQS) The CAA requires the EPA to regulate emissions of pollutants considered harmful to public health and the environment. The EPA has established NAAQS for six such pollutants, including SO_2 and ozone. Each state is responsible for developing a SIP that will attain and maintain the NAAQS. These plans may result in the imposition of emission limits on our facilities. SO_2 Designations for Texas In November 2016, the EPA finalized its nonattainment designations for counties surrounding our Martin Lake generation plant and our now retired Big Brown and Monticello plants. The final designations require Texas to develop nonattainment plans for these areas. In February 2017, the State of Texas and Luminant filed challenges to the nonattainment designations in the Fifth Circuit Court. In August 2019, the EPA issued a proposed Error Correction Rule for all three areas, which, if finalized, would have revised its previous nonattainment designations and each area at issue would be designated unclassifiable. In May 2021, the EPA finalized a "Clean Data" determination for the areas surrounding the retired Big Brown and Monticello plants, redesignating those areas as attainment based on monitoring data supporting an attainment designation. In June 2021, the EPA published two notices; one that it was withdrawing the August 2019 Error Correction Rule and a second separate notice denying petitions from Luminant and the State of Texas to reconsider the original nonattainment designations. We, along with the State of Texas, challenged that EPA action and have consolidated it with the pending challenge in the Fifth Circuit Court, and this case was argued before the Fifth Circuit Court in July 2022. In September 2021, the TCEQ considered a proposal for its nonattainment SIP revision for the Martin Lake area and an agreed order to reduce SO 2 emissions from the plant. The proposed agreed order associated with the SIP proposal reduces emission limits as of January 2022. Emission reductions required are those necessary to demonstrate attainment with the NAAQS. The TCEQ's SIP action was finalized in February 2022 and has been submitted to the EPA for review and approval. Ozone Designations The EPA issued a final rule in October 2015 lowering the ozone NAAQS from 75 to 70 parts per billion. Areas surrounding our Dicks Creek, Miami Fort and Zimmer facilities in Ohio, our Calumet facility in Illinois and our Wise, Ennis and Midlothian facilities in Texas were designated marginal nonattainment areas in June 2018 by the EPA with an attainment deadline of August 2021. The EPA is required to take action on areas that did not attain by that date by bumping up the region to a "moderate" designation with an attainment deadline of August 2024. States will be required to develop SIPs to address emissions in areas with a higher (more stringent) classification. CCR/Groundwater The combustion of coal to generate electric power creates large quantities of ash and byproducts that are managed at power generation facilities in dry form in landfills and in wet form in surface impoundments. Each of our coal-fueled plants has at least one CCR surface impoundment. At present, CCR is regulated by the states as solid waste. Coal Combustion Residuals The EPA's CCR rule, which took effect in October 2015, establishes minimum federal requirements for the construction, retrofitting, operation and closure of, and corrective action with respect to, existing and new CCR landfills and surface impoundments, as well as inactive CCR surface impoundments. The requirements include location restrictions, structural integrity criteria, groundwater monitoring, operating criteria, liner design criteria, closure and post-closure care, recordkeeping and notification. The deadlines for beginning and completing closure vary depending on several factors. The Water Infrastructure Improvements for the Nation Act (the WIIN Act), which was enacted in December 2016, provides for EPA review and approval of state CCR permit programs. In August 2018, the D.C. Circuit Court issued a decision that vacates and remands certain provisions of the 2015 CCR rule, including an applicability exemption for legacy impoundments. In August 2020, the EPA issued a final rule establishing a deadline of April 11, 2021 to cease receipt of waste and initiate closure at unlined CCR impoundments. The final rule allows a generation plant to seek the EPA's approval to extend this deadline if no alternative disposal capacity is available and either a conversion to comply with the CCR rule is underway or retirement will occur by either 2023 or 2028 (depending on the size of the impoundment at issue). Prior to the November 2020 deadline, we submitted applications to the EPA requesting compliance extensions under both conversion and retirement scenarios. In November

2020, environmental groups petitioned for review of this rule in the D.C. Circuit Court, and Vistra subsidiaries filed a motion to intervene in support of the EPA in December 2020. Also, in November 2020, the EPA finalized a rule that would allow an alternative liner demonstration for certain qualifying facilities. In November 2020, we submitted an alternate liner demonstration for one CCR unit at Martin Lake. In August 2021, we submitted a request to transfer our conversion application for the Zimmer facility to a retirement application following announcement that Zimmer will close by May 31, 2022. In January 2022, the EPA determined that our conversion and retirement applications for our CCR facilities were complete but has not yet proposed action on any of those applications. In addition, in January 2022, the EPA also made a series of public statements, including in a press release, that purported to impose new, more onerous closure requirements for CCR units. The EPA issued these new purported requirements without prior notice and without following the legal requirements for adopting new rules. These new purported requirements announced by the EPA are contrary to existing regulations and the EPA's prior positions. In April 2022, we, along with the Utility Solid Waste Activities Group (USWAG), a trade association of over 130 utility operating companies, energy companies, and certain other industry associations, filed petitions for review with the D.C. Circuit Court and have asked the court to determine that the EPA cannot implement or enforce the new purported requirements because the EPA has not followed the required procedures. The State of Texas and the TCEQ have intervened in support of the petitions filed by the Vistra subsidiaries and USWAG, and various environmental groups have intervened on behalf of the EPA. Briefing on this petition will be complete by May 2023. MISO In 2012, the Illinois Environmental Protection Agency (IEPA) issued violation notices alleging violations of groundwater standards onsite at our Baldwin and Vermilion facilities' CCR surface impoundments. These violation notices remain unresolved; however, in 2016, the IEPA approved our closure and post-closure care plans for the Baldwin old east, east, and west fly ash CCR surface impoundments. We have completed closure activities at those ponds at our Baldwin facility. At our retired Vermilion facility, which was not potentially subject to the EPA's 2015 CCR rule until the aforementioned D.C. Circuit Court decision in August 2018, we submitted proposed corrective action plans involving closure of two CCR surface impoundments (i.e. , the old east and the north impoundments) to the IEPA in 2012, and we submitted revised plans in 2014. In May 2017, in response to a request from the IEPA for additional information regarding the closure of these Vermilion surface impoundments, we agreed to perform additional groundwater sampling and closure options and riverbank stabilizing options. In May 2018, Prairie Rivers Network (PRN) filed a citizen suit in federal court in Illinois against Dynegy Midwest Generation, LLC (DMG), alleging violations of the Clean Water Act for alleged unauthorized discharges. In August 2018, we filed a motion to dismiss the lawsuit. In November 2018, the district court granted our motion to dismiss and judgment was entered in our favor. In June 2021, the U.S. Court of Appeals for the Seventh Circuit affirmed the district court's dismissal of the lawsuit. In April 2019, PRN also filed a complaint against DMG before the Illinois Pollution Control Board (IPCB), alleging that groundwater flows allegedly associated with the ash impoundments at the Vermilion site have resulted in exceedances both of surface water standards and Illinois groundwater standards dating back to 1992. We answered that complaint in July 2021, and this matter is currently abated. In 2012, the IEPA issued violation notices alleging violations of groundwater standards at the Newton and Coffeen facilities' CCR surface impoundments. We are addressing these CCR surface impoundments in accordance with the federal CCR rule. In June 2018, the IEPA issued a violation notice for alleged seep discharges claimed to be coming from the surface impoundments at our retired Vermilion facility, which is owned by our subsidiary DMG, and that notice was referred to the Illinois Attorney General. In June 2021, the Illinois Attorney General and the Vermilion County State Attorney filed a complaint in Illinois state court with an agreed interim consent order which the court subsequently entered. Given the violation notices and the enforcement action, the unique characteristics of the site, and the proximity of the site to the only national scenic river in Illinois, we agreed to enter into the interim consent order to resolve this matter. Per the terms of the agreed interim consent order, DMG is required to evaluate the closure alternatives under the requirements of the newly implemented Illinois Coal Ash regulation (discussed below) and close the site by removal. In addition, the interim consent order requires that during the impoundment closure process, impacted groundwater will be collected before it leaves the site or enters the nearby Vermilion river and, if necessary, DMG will be required to install temporary riverbank protection if the river migrates within a certain distance of the impoundments. The interim order was modified in December 2022 to require certain amendments to the Safety Emergency Response Plan. These proposed closure costs are reflected in the ARO in our consolidated balance sheets (see Note 20 to the Financial Statements). In July 2019, coal ash disposal and storage legislation in Illinois was enacted. The legislation addresses state requirements for the proper closure of coal ash ponds in the state of Illinois. The law tasks the IEPA and the IPCB to set up a series of guidelines, rules and permit requirements for closure of ash ponds. Under the final rule, which was finalized and became effective in April 2021, coal ash impoundment owners would be required to submit a closure alternative analysis to the IEPA for the selection of the best method for coal ash remediation at a particular site. The rule does not mandate closure by removal at any site. In May 2021, we filed an appeal in the Illinois Fourth Judicial District over certain provisions of the final rule and that case remains pending. Other parties have also filed appeals of certain provisions of the final rule. In October 2021, we filed operating permit applications for 18 impoundments as required by the Illinois coal ash rule, and filed construction permit applications for three of our sites in January 2022 and five of our sites in July 2022. One additional closure construction application will be filed for our Baldwin facility in 2023. For all of the above matters, if certain corrective action measures, including groundwater treatment or removal of ash, are required at any of our coal-fueled facilities, we may incur significant costs that could have a material adverse effect on our financial condition, results of operations and cash flows. The Illinois coal ash rule was finalized in April 2021 and does not require removal. However, the rule required us to undertake further site specific evaluations required by each program. We will not know the full range of decommissioning costs, including groundwater remediation, if any, that ultimately may be required under the Illinois rule until permit applications have been approved by the IEPA. However, the currently anticipated CCR surface impoundment and landfill closure costs, as reflected in our existing ARO liabilities, reflect the costs of closure methods that our operations and environmental services teams believe are appropriate and protective of the environment for each location. Water The EPA and the environmental regulatory bodies of states in which we operate have jurisdiction over the diversion, impoundment and withdrawal of water for cooling and other purposes and the discharge of wastewater (including storm water) from our facilities. We believe our facilities are presently in material compliance with applicable federal and state requirements relating to these activities. We believe we hold all required permits relating to these activities for facilities in operation and have applied for or obtained necessary permits for facilities under construction. We also believe we can satisfy the requirements necessary to obtain any required permits or renewals. Effluent Limitation Guidelines (ELGs) In November 2015, the EPA revised the ELGs for steam electricity generation facilities, which will impose more stringent standards (as individual permits are renewed) for wastewater streams, such as FGD, fly ash, bottom ash and flue gas mercury control wastewaters. Various parties filed petitions for review of the ELG rule, and the petitions were consolidated in the Fifth Circuit Court. In April 2017, the EPA granted petitions requesting reconsideration of the ELG rule and administratively stayed the rule's compliance date deadlines. In April 2019, the Fifth Circuit Court vacated and remanded portions of the EPA's ELG rule pertaining to effluent limitations for legacy wastewater and leachate. The EPA published a final rule in October 2020 that extends the compliance date for both FGD and bottom ash transport water to no later than December 2025, as negotiated with the state permitting agency. Additionally, the final rule allows for a retirement exemption that exempts facilities certifying that units will retire by December 2028 provided certain effluent limitations are met. In November 2020, environmental groups petitioned for review of the new ELG revisions, and Vistra subsidiaries filed a motion to intervene in support of the EPA in December 2020. In July 2021, the EPA announced its intent to revise the ELG rule and moved to hold the 2020 ELG revision litigation in abeyance pending the EPA's completion of its reconsideration rulemaking. Notifications were made to Texas, Illinois and Ohio state agencies on the retirement exemption for applicable coal plants by the regulatory deadline of October 13, 2021. Radioactive Waste The nuclear industry has developed ways to store used nuclear fuel on site at nuclear generation facilities, primarily using dry cask storage, since there are no facilities for reprocessing or disposal of used nuclear fuel currently in operation in the U.S. Luminant stores its used nuclear fuel on-site in storage pools or dry cask storage facilities and believes its on-site used nuclear fuel storage capability is sufficient for the foreseeable future. Item 1A. RISK FACTORS Summary of Risk Factors The following summarizes the principal factors that make an investment in our company speculative or risky, all of which are more fully described in the Risk Factors section below. This summary should be read in conjunction with the Risk Factors section and should not be relied upon as an exhaustive summary of the material risks facing our business. The following factors could result in harm to our business, financial condition, results of operations, cash flows, and prospects, among other impacts: Market, Financial and Economic Risks Our revenues, results of operations and operating cash flows are affected by price fluctuations in the wholesale power market and other market factors beyond our control. We purchase natural gas, coal, fuel oil, and nuclear fuel for our generation facilities, and higher than expected fuel costs or disruptions in these fuel markets may have an adverse impact on, our costs, revenues, results of operations, financial condition and cash flows. We have retired, announced planned retirements of, and may be forced to retire or idle additional underperforming generation units which could result in significant costs and have an adverse effect on our operating results. Our assets or positions cannot be fully hedged against changes in commodity prices and market heat rates, and hedging transactions may not work as planned or hedge counterparties may default on their obligations. Competition, changes in market structure, and/or state or federal interference in the wholesale and retail power markets, together with subsidized generation, may have a material adverse effect on our financial condition, results of operations and cash flows. Our results of operations and financial condition could be materially and adversely affected by energy market participants continuing to construct new generation facilities or expanding or enhancing existing generation facilities despite relatively low power prices and such additional generation capacity results in a reduction in wholesale power prices. Our liquidity needs could be difficult to satisfy, particularly during times of uncertainty in the financial markets or during times of significant fluctuation in commodity prices, and we may be unable to access capital on favorable terms or at all in the future, which could have a material adverse effect on us. The agreements and instruments governing our debt, including the Vistra Operations Credit Facilities and indentures, contain restrictions and limitations that could affect our ability to operate our business, our liquidity, and our results of operations, and any failure to comply with these restrictions could have a material adverse effect on us. We may not be able to complete future acquisitions on favorable terms or at all, successfully integrate future acquisitions into our business, or effectively identify and invest in value-creating businesses, assets or projects, which could result in unanticipated expenses and losses or otherwise hinder or delay our growth strategy. Our ability to achieve the expected growth of our Vistra Zero portfolio, consisting of our solar generation, ESS, and other renewables development projects, is subject to substantial capital requirements and other significant uncertainties. Tax legislation initiatives or challenges to our tax positions, or potential future legislation or the imposition of new or increased taxes or fees, could have a material adverse effect on our financial condition, results of operations and cash flows. We are required to pay the holders of TRA Rights for certain tax benefits, which amounts are expected to be substantial. Regulatory and Legislative Risks Our businesses are subject to ongoing complex governmental regulations and legislation that have adversely impacted, and may in the future adversely impact, our businesses, results of operations, liquidity and financial condition. Our cost of compliance with existing and new environmental laws could have a material adverse effect on us. Pending or proposed laws or regulations, including those proposed or implemented under the Biden administration, could have a material adverse effect on our businesses, results of operations, liquidity and financial condition. Changes to laws, rules or regulations related to market structures in the markets in which we participate may have a material adverse effect on our businesses, results of operation, liquidity and financial condition. We could be materially and adversely affected if current regulations are implemented or if new federal or state legislation or regulations are adopted to address global climate change, or if we are subject to lawsuits for alleged damage to persons or property resulting from greenhouse gas emissions. Litigation, legal proceedings, regulatory investigations or other administrative proceedings could expose us to significant liabilities and reputational damage that could have a material adverse effect on us. Operational Risks Volatile power supply costs and demand for power have and could in the future adversely affect the financial performance of our retail businesses. Our retail operations are subject to significant competition from other REPs, which could result in a loss of existing customers and the inability to attract new customers. The operation of our businesses is subject to information security and operational technology risks, including cybersecurity breaches and failure of critical information and operations technology systems. Attacks on our infrastructure that breach cyber/data security measures could expose us to significant liabilities, reputational damage, regulatory action, and disrupt business operations, which could have a material adverse effect on us. We may suffer material losses, costs and liabilities due to operational risks, regulatory risks, and the risk of nuclear accidents arising from the ownership and operation of the Comanche Peak nuclear generation facility. The operation and maintenance of power generation facilities and related mining operations are capital intensive and involve significant risks that could adversely affect our results of operations, liquidity and financial condition. We may be materially and adversely affected by obligations to comply with federal and state regulations, laws, and other legal requirements that govern the operations, assessments, storage, closure, corrective action, disposal and monitoring relating to CCR. We have been and may in the future be materially and adversely affected by, the effects of extreme weather conditions and seasonality. Events outside of our control, including an epidemic or outbreak of an infectious disease, such as COVID-19, may materially adversely affect our business. Changes in technology, increased electricity conservation efforts, or energy sustainability efforts may reduce the value of our generation facilities and may otherwise have a material adverse effect on us. Risks Related to Our Structure and Ownership of our Common Stock Evolving expectations from stakeholders, including investors, on ESG issues, including climate change and sustainability matters, and erosion of stakeholder trust or confidence could influence actions or decisions about our company and our industry and could adversely affect our business, operations, financial results, or stock price. We may not pay any dividends on our common stock in the future, and we may not realize the anticipated benefits of our share repurchase program. Please carefully consider the following discussion of significant factors, events, and uncertainties that make an investment in our securities risky. These factors, in addition to others specifically addressed in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations (MDA) , provide important information for the understanding of our forward-looking statements in this annual report on Form 10-K. If one or more of the factors, events and uncertainties discussed below or in the MDA were to materialize, our business, results of operations, liquidity, financial condition, cash flows, reputation or prospects could be materially adversely affected. In addition, if one or more of such factors, events and uncertainties were to materialize, it could cause results or outcomes to differ materially from those contained in or implied by any forward-looking statement in this annual report on Form 10-K. There may be further risks and uncertainties that are not currently known or that are not currently believed to be material that may adversely affect our business, results of operations, liquidity, financial condition and prospects and the market price of our common stock in the future. The realization of any of these factors could cause investors in our securities (including our common stock) to lose all or a substantial portion of their investment. Market, Financial and Economic Risks Our revenues, results of operations and operating cash flows generally are affected by price fluctuations in the wholesale power market and other market factors beyond our control. We are not guaranteed any rate of return on capital investments in our businesses. We conduct integrated power generation and retail electricity activities, focusing on power generation, wholesale electricity sales and purchases, retail sales of electricity and natural gas to end users and commodity risk management. Our wholesale and retail businesses are to some extent countercyclical in nature, particularly for the wholesale power and ancillary services supplied to the retail business. However, we do have a wholesale power position that is subject to wholesale power price moves, which may be significant. As a result, our revenues, results of operations and operating cash flows depend in large part upon wholesale market prices for electricity, natural gas, uranium, lignite, coal, fuel, and transportation in our regional markets and other competitive markets in which we operate and upon prevailing retail electricity rates, which may be impacted by, among other things, actions of regulatory authorities. Market prices for power, capacity, ancillary services, natural gas, coal and fuel oil are unpredictable and may fluctuate substantially over relatively short periods of time. Unlike most other commodities, electric power can only be stored on a very limited basis and generally must be produced concurrently with its use. As a result, power prices are subject to significant volatility due to supply and demand imbalances, especially in the day-ahead and spot markets. Demand for electricity can fluctuate dramatically, creating periods of substantial under- or over-supply. Over-supply can occur as a result of the construction of new power generation sources, as we have observed in recent years. During periods of over-supply, electricity prices might be depressed. For example, the cost of electricity from renewable resources, such as solar, wind and battery ESS, has dropped substantially in recent years. In many instances, energy from these sources are bid into the relevant spot market at a price of zero or close to zero during certain times of the day, lowering the clearing price for all power wholesalers in such market. Also, at times there is political pressure, or pressure from regulatory authorities with jurisdiction over wholesale and retail energy commodity and transportation rates, to impose price limitations, bidding rules and other mechanisms to address volatility and other issues in these markets. Extreme weather events can also materially impact power prices or otherwise exacerbate conditions or circumstances that result in volatility of power prices. For example, in February 2021, the U.S. experienced Winter Storm Uri and extreme cold temperatures in the central U.S., including Texas. This severe weather event substantially increased the demand for natural gas used in our electric power generation business, and the cold further limited the availability of renewable generation across the region contributing to extremely high market prices for natural gas and electricity, which resulted in substantial increases in the costs to procure sufficient fuel supply and increased collateral posting requirements. Winter Storm Elliott, in December 2022, was another example of extreme weather across the U.S. that resulted in widespread wholesale power market volatility. The majority of our facilities operate as "merchant" facilities without long-term power sales agreements. As a result, we largely sell electric energy, capacity and ancillary services into the wholesale energy spot market or into other wholesale and retail power markets on a short-term basis and are not guaranteed any rate of return on our capital investments. Consequently, there can be no assurance that we will be able to sell any or all of the electric energy, capacity or ancillary services from those facilities at commercially attractive rates or that our facilities will be able to operate profitably. We depend, in large part, upon prevailing market prices for power, capacity and fuel. Given the volatility of commodity power prices, to the extent we are unable to hedge or otherwise secure long-term power sales agreements for the output of our power generation facilities, our revenues and profitability will be subject to volatility, and our financial condition, results of operations and cash flows could be materially adversely affected. We purchase natural gas, coal, fuel oil, and nuclear fuel for our generation facilities, and higher than expected fuel costs, volatility, or disruption in these fuel markets may have an adverse impact on our costs, revenues, results of operations, financial condition and cash flows. We rely on natural gas, coal, fuel oil, and nuclear fuel for the majority of our power generation facilities. Delivery of these fuels to the facilities is dependent upon the continuing availability of such fuels and financial viability of contractual counterparties as well as upon the infrastructure (including mines, rail lines, rail cars, barge facilities, roadways, riverways and natural gas pipelines) available and functioning to serve each generation facility, and geopolitical risk, including the current Russia and Ukraine conflict and the potential for additional U.S. sanctions against Russia. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Significant

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Activities and Events and Items Influencing Future Performance - Macroeconomic Conditions . As a result, we have experienced, and remain subject to the risks of disruptions or curtailments in the production of power at our generation facilities if no fuel is available at any price, if a counterparty fails to perform or if there is a disruption in the fuel delivery infrastructure. Certain of our generation facilities rely on a limited number of counterparties, such as natural gas suppliers and railcar companies, to provide the necessary fuel. Disputes relating to or non-performance of contractual arrangements, have resulted in, and may continue to result in adverse impacts to our costs, revenues, results of operations, financial condition, and cash flows. As part of our strategy to mitigate the potential negative effects of commodity price volatility, we have sold forward a substantial portion of our expected power sales in the next three years in order to lock in long-term prices. In order to hedge our obligations under these forward power sales contracts, we have entered into long-term and short-term contracts for the purchase and delivery of fuel. Many of the forward power sales contracts do not allow us to pass through changes in fuel costs or discharge the power sale obligations in the case of a disruption in fuel supply due to force majeure events or the default of a fuel supplier or transporter. Fuel costs (including diesel, natural gas, lignite, coal and nuclear fuel) are volatile, and the wholesale price for electricity does not always change at the same rate as changes in fuel costs, and disruptions in our fuel supplies may therefore require us to find alternative fuel sources at costs which may be higher than planned, to find other sources of power to deliver to counterparties at a higher cost, or to pay damages to counterparties for failure to deliver power as contracted. Long-term and short-term contracts are subject to risk of non-delivery or claims of force majeure, which may impact our ability to economically recover the value of the contract. In addition, we purchase and sell natural gas and other energy related commodities, and volatility in these markets may affect costs incurred in meeting our obligations. Further, any changes in the costs of natural gas, coal, fuel oil, nuclear fuel or transportation rates and changes in the relationship between such costs and the market prices of power will affect our financial results. If we are unable to procure fuel for physical delivery at prices we consider favorable, or if we are unable to procure these fuels at all, our financial condition, results of operations and cash flows could be materially adversely affected. For example, supply challenges were among the primary drivers of the significant loss experienced in 2021 as a result of Winter Storm Uri. We also buy significant quantities of fuel on a short-term or spot market basis. Prices for all of our fuels fluctuate, sometimes rising or falling significantly over a relatively short period of time. The price we can obtain for the sale of energy may not rise at the same rate, or may not rise at all, to match a rise in fuel or delivery costs. This may have a material adverse effect on our financial and operating performance. Volatility in market prices for fuel and electricity results from, among other factors: demand for energy commodities and general economic conditions, including impacts of inflation and the relative strength or weakness of U.S. dollar compared to other currencies; volatility in commodity prices and the supply of commodities, including but not limited to natural gas, coal and fuel oil;

volatility in market heat rates; volatility in coal and rail transportation prices; volatility in nuclear fuel and related enrichment and conversion services; transmission or transportation disruptions, constraints, congestion, inoperability or inefficiencies of electricity, natural gas or coal transmission or transportation, or other changes in power transmission infrastructure; severe, sustained or unexpected weather conditions, including extreme cold, drought and limitations on access to water; seasonality; changes in electricity and fuel usage resulting from conservation efforts, changes in technology or other factors; illiquidity in the wholesale electricity or other commodity markets; importation of liquified natural gas to certain markets; development and availability of new fuels, new technologies and new forms of competition for the production and storage of power, including competitively priced alternative energy sources or storage; changes in market structure and liquidity; changes in the way we operate our facilities, including curtailed operation due to market pricing, environmental regulations and legislation, safety or other factors; changes in generation capacity or efficiency; outages or otherwise reduced output from our generation facilities or those of our competitors; changes in electric capacity, including the addition of new supplies of power as a result of the development of new plants, expansion of existing plants, the continued operation of uneconomic power plants due to federal, state or local subsidies, or additional transmission capacity; local, regional, national, or global supply chain constraints or shortages; our creditworthiness and liquidity and the willingness of fuel suppliers and transporters to do business with us; changes in the credit risk, payment practices, or financial condition of market participants; changes in production and storage levels of natural gas, lignite, coal, uranium, diesel and other refined products; pandemics and epidemics (including the impacts thereto, or recovery therefrom), natural disasters, wars, sabotage, terrorist acts, embargoes and other catastrophic events; and changes in law, including judicial decisions, federal, state and local energy, environmental and other regulation and legislation. See " Economic downturns would likely have a material adverse effect on our businesses" for a discussion of potential risks arising from current U.S. and global economic and geopolitical conditions. We have retired, announced planned retirements of, and may be forced to retire or idle additional underperforming generation units which could result in significant costs and have an adverse effect on our operating results. A sustained decrease in the financial results from, or the value of, our generation units has resulted in the retirement or planned retirement of, and ultimately could result in additional retirements or idling of, generation units. We have operated certain of our lignite- and coal-fueled generation assets only during parts of the year that have higher electricity demand and, therefore, higher related wholesale electricity prices. In connection with the closure and remediation of retired generation units, we have spent, and may in the future spend, a significant amount of money, internal resources and time to complete the required closure and reclamation, which could have a material adverse effect on our financial and operating performance. Our assets or positions cannot be fully hedged against changes in commodity prices and market heat rates, and hedging transactions may not work as planned, or counterparties may default on their obligations, which could have a material adverse impact on our business, financial condition, results of operations and cash flows. Our hedging activities do not fully protect us against the risks associated with changes in commodity prices, most notably electricity and natural gas prices, because of the expected useful life of our generation assets and the size of our position relative to the duration of available markets for various hedging activities. Generally, commodity markets that we participate in to hedge our exposure to electricity prices and heat rates have limited liquidity after two to three years. Further, our ability to hedge our revenues by utilizing cross-commodity hedging strategies with natural gas hedging instruments is generally limited to a duration of four to five years. To the extent we have unhedged positions, fluctuating commodity prices and/or market heat rates can materially impact our results of operations, cash flows, liquidity and financial condition, either favorably or unfavorably. To manage our financial exposure related to commodity price fluctuations, we routinely enter into contracts to hedge portions of purchase and sale commitments, fuel requirements and inventories of natural gas, lignite, coal, diesel fuel, uranium and refined products, and other commodities, within established risk management guidelines. As part of this strategy, we routinely utilize fixed-price forward physical purchase and sale contracts, futures, financial swaps and option contracts traded in over-the-counter markets or on exchanges. Given our exposure to risks of commodity price movements, we devote a considerable amount of time and effort to the establishment of risk management policies and procedures, as well as the ongoing review of the implementation of these policies and procedures. Additionally, we have processes and controls in place that are designed to monitor and accurately report hedging activities and positions. The policies, procedures, processes and controls in place may not always function as planned and cannot eliminate all the risks associated with these activities, including unauthorized hedging activity, or improper reporting thereof, by our employees in violation of our existing risk management policies and procedures. For example, we hedge the expected needs of our wholesale and retail customers, but unexpected changes due to weather, natural disasters, consumer behavior, market constraints or other factors could cause us to purchase electricity to meet unexpected demand in periods of high wholesale market prices or resell excess electricity into the wholesale market in periods of low prices. As a result of these and other factors, the impacts of our commodity hedging activities and risk management decisions may have a material adverse effect on our business, financial condition, results of operations and cash flows. Based on economic and other considerations, including our available liquidity, we may not be able to, or we may decide not to, hedge the entire exposure of our operations to commodity price risk. To the extent we do not hedge against commodity price risk and applicable commodity prices change in ways adverse to us, we could be materially and adversely affected. To the extent we do hedge against commodity price risk, those hedges may ultimately prove to be ineffective. Additionally, there may be changes to existing laws or regulations that could significantly impact our ability to effectively hedge, which may have a material adverse effect on us. With the continued tightening of credit markets that began in 2008 and expansion of regulatory oversight through various financial reforms, there has been a decline in the number of market participants in the wholesale energy commodities markets, resulting in less liquidity. Notably, participation by financial institutions and other intermediaries (including investment banks) in such markets has declined. Extended declines in market liquidity could adversely affect our ability to hedge our financial exposure to desired levels. To the extent we engage in hedging and risk management, and power purchase agreement activities, we are exposed to the credit risk that counterparties that owe us money, energy or other commodities as a result of these activities will not perform their obligations to us. Should the counterparties to these arrangements fail to perform, we could be forced to enter into alternative hedging arrangements or honor the underlying commitment at then-current market prices. Additionally, our counterparties may seek bankruptcy protection under Chapter 11 or liquidation under Chapter 7 of the Bankruptcy Code. Our credit risk may be exacerbated to the extent collateral held by us cannot be realized or is liquidated at prices not sufficient to recover the full amount due to us. There can be no assurance that any such losses or impairments to the carrying value of our financial assets would not materially and adversely affect our financial condition, results of operations and cash flows. In such event, we could incur losses or forgo expected gains in addition to amounts, if any, already paid to the counterparties. Market participants in the ISOs/RTOs in which we operate are also exposed to risks that another market participant may default on its obligations to pay such ISO/RTO for electricity or services taken, in which case such costs, to the extent not offset by posted security and other protections available to such ISO/RTO, may be allocated to various non-defaulting ISO/RTO market participants, including us. We do not apply hedge accounting to our commodity derivative transactions, which may cause increased volatility in our quarterly and annual financial results. We engage in economic hedging activities to manage our exposure related to commodity price fluctuations through the use of financial and physical derivative contracts for commodities. These derivatives are accounted for in accordance with GAAP, which requires that we record all derivatives on the balance sheet at fair value with changes in fair value immediately recognized in earnings as unrealized gains or losses. GAAP permits an entity to designate qualifying derivative contracts as normal purchases and sales. If designated, those contracts are not recorded at fair value. GAAP also permits an entity to designate qualifying derivative contracts in a hedge accounting relationship. If a hedge accounting relationship is used, a significant portion of the changes in fair value is not immediately recognized in earnings. We have elected not to apply hedge accounting to our commodity contracts, and we have designated contracts as normal purchases and sales in only limited cases, such as certain retail sales contract portfolios. As a result, our quarterly and annual financial results in accordance with GAAP are subject to significant fluctuations caused by changes in forward commodity prices. Competition, changes in market structure, and/or state or federal interference in the wholesale and retail power markets, together with subsidized generation, may have a material adverse effect on our financial condition, results of operations and cash flows. Our generation and competitive retail businesses rely on a competitive wholesale marketplace. The competitive wholesale marketplace may be undermined by changes in market structure and out-of-market subsidies provided by federal or state entities, including bailouts of uneconomic plants, imports of power from Canada, renewable mandates or subsidies, as well as out-of-market payments to new generators. Multiple potential changes are currently being evaluated by the PUCT and the Texas legislature for the ERCOT market, including the PCM that would align a required reliability standard with resource availability during higher-risk system conditions, the ultimate resolution of which is unknown. Our power generation business competes with other non-utility generators, regulated utilities, unregulated subsidiaries of regulated utilities, other energy service companies and financial institutions in the sale of electric energy, capacity and ancillary services, as well as in the procurement of fuel, transmission and transportation services. Moreover, aggregate demand for power may be met by generation capacity based on several competing technologies, as well as power generating facilities fueled by alternative or renewable energy sources, including hydroelectric power, synthetic fuels, solar, wind, wood, geothermal, waste heat and solid waste sources. Regulatory initiatives designed to enhance and/or subsidize renewable generation increases competition from these types of facilities and out-of-market subsidies to existing or new generation can undermine the competitive wholesale marketplace, which can lead to premature retirement of existing facilities, including those owned by us. We also compete against other energy merchants on the basis of our relative operating skills, financial position and access to credit sources. Electric energy customers, wholesale energy suppliers and transporters often seek financial guarantees, credit support such as letters of credit and other assurances that their energy contracts will be satisfied. Companies with which we compete may have greater resources or experience in these areas. Over time, some of our plants may become unable to compete because of subsidized generation, including public utility commission supported power purchase agreements, and the construction of new plants. Such new plants could have a number of advantages including more efficient equipment and newer technology that could result in fewer emissions or more advantageous locations on the electric transmission system. Additionally, these competitors may be able to respond more quickly to new laws and regulations because of the newer technology utilized in their facilities or the additional resources derived from owning more efficient facilities. Other factors may contribute to increased competition in wholesale power markets. We expect that we will continue to face intense competition from numerous companies, including new entrants or consolidation of existing competitors, in the industry. Certain federal and state entities in jurisdictions in which we operate have either enacted or are considering regulations or legislation to subsidize otherwise uneconomic plants and attempt to incentivize, including through certain tax benefits, the construction and development of additional renewable resources as well as increases in energy efficiency investments. For example, the Inflation Reduction Act of

2022 contains a number of tax credits and incentives relating to renewable projects and clean energy technologies such as nuclear energy. New entrants or existing competitors may find it more economical to develop new renewable projects or invest in clean energy technologies in which we would like to invest. Subsidies (or increases thereto) to our competitors could result in increased competition for us, which could have a material adverse effect on our financial condition, results of operations and cash flows. In addition, our retail marketing efforts compete for customers in a competitive environment, which impacts the margins that we can earn on the volumes we are able to serve. Further, with retail competition, it is easier for residential customers where we serve load to switch to and from competitive electricity generation suppliers for their energy needs. The volatility and uncertainty that results from such mobility may have material adverse effects on our financial condition, results of operations and cash flows. For example, if fewer customers switch to another supplier than anticipated, the load we must serve will be greater than anticipated and, if market prices of fuel have increased, our costs will increase more than expected due to the need to go to the market to cover the incremental supply obligation. If more customers switch to another supplier than anticipated, the load we must serve will be lower than anticipated and, if market prices of electricity have decreased, our operating results could suffer. Our results of operations and financial condition could be materially and adversely affected by energy market participants continuing to construct new generation facilities or expanding or enhancing existing generation facilities despite relatively low power prices and such additional generation capacity results in a reduction in wholesale power prices. Given the overall attractiveness of certain of the markets in which we operate and certain tax benefits associated with renewable energy, among other matters, energy market participants have continued to construct new generation facilities or invest in enhancements or expansions of existing generation facilities despite relatively low wholesale power prices. Assuming this market dynamic continues, our results of operations and financial condition could be materially and adversely affected if such additional generation capacity results in an over-supply of electricity that causes a reduction in wholesale power prices. Additionally, new or existing market participants without, or with less, fossil fuel operations may gain additional market share, or reduce our market share, due to evolving expectations and sentiments of key stakeholders, government, and regulatory authorities regarding our operations and activities. Economic downturns would likely have a material adverse effect on our businesses. Our results of operations may be negatively affected by sustained downturns or sluggishness in the economy, including lower prices for power, generation capacity and natural gas, which can fluctuate substantially. Increased unemployment of residential customers and decreased demand for products and services by commercial and industrial customers resulting from an economic downturn could lead to declines in the demand for energy and an increase in the number of uncollectible customer balances, which would negatively impact our overall sales and cash flows. The convergence of current global conditions, including sustained inflation, rising interest rates, and the geopolitical climate, has and could lead to, or accelerate or exacerbate the occurrence of, a significant economic downturn, as well as changes in consumer and counterparty behavior, higher costs of capital, decreases in the value of our existing long-dated contracts, commodity price increases and volatility, supply chain shortages, and other adverse impacts to our business. Additionally, prolonged economic downturns that negatively impact our financial condition, results of operations and cash flows could result in future material impairment charges to write down the carrying value of certain assets to their respective fair values. Our liquidity needs could be difficult to satisfy, particularly during times of uncertainty in the financial markets or during times of significant fluctuation in commodity prices, and we may be unable to access capital on favorable terms or at all in the future, which could have a material adverse effect on us. We currently maintain non-investment grade credit ratings that could negatively affect our ability to access capital on favorable terms or result in higher collateral requirements, particularly if our credit ratings were to be downgraded in the future. Our businesses are capital intensive. In general, we rely on access to financial markets and credit facilities as a significant source of liquidity for our capital requirements, hedging transactions and other obligations not satisfied by cash-on-hand or operating cash flows. The inability to raise capital or to access credit facilities, particularly on favorable terms, could adversely impact our liquidity and our ability to meet our obligations or sustain and grow our businesses and could increase capital costs and collateral requirements, any of which could have a material adverse effect on us. Our access to capital and the cost and other terms of acquiring capital are dependent upon, and could be adversely impacted by, various factors, including: general economic and capital markets conditions, including changes in financial markets that reduce available liquidity or the ability to obtain or renew credit facilities on favorable terms or at all; conditions and economic weakness in the U.S. power markets; regulatory developments; changes in interest rates; a deterioration, or perceived deterioration, of our creditworthiness, enterprise value or financial or operating results; a downgrade of Vistra's or its applicable subsidiaries' credit ratings, or credit ratings of its issuances; our level of indebtedness and compliance with covenants in our debt agreements; our ability to meet our sustainability targets in our secured credit facilities; a deterioration of the creditworthiness or bankruptcy of one or more lenders or counterparties under our credit facilities that affects the ability of such lender(s) to make loans to us; credit, security, or collateral requirements, including those relating to volatility in commodity prices; general credit availability from banks or other lenders for us and our industry peers; investor and lender confidence in and sentiment of the industry, our business, and the wholesale electricity markets in which we operate; a material breakdown in or oversight in effectuating our risk management procedures; the occurrence of changes in our businesses; disruptions, constraints, or inefficiencies in the continued reliable operation of our generation facilities and ESSs; and changes in or the operation of provisions of tax and regulatory laws. There are also increasing financial risks for companies that own and operate fossil fuel generation as institutional lenders or other sources of capital have become more attentive to sustainable financing practices and some of them may seek commitments on emission reduction targets or expected use or proceeds when providing funding to, or decline to provide funding for companies who produce or utilize fossil fuel energy or that have higher levels of GHG emissions. We amended our Vistra Operations Credit Agreement to build in Sustainability Adjustments. These adjustments use baseline values from KPI Metrics and provide for decreases in the applicable credit spread adjustments and commitment fee rates if our reported metrics are a certain percentage below the baseline values, adjusted on a year to year basis. Conversely, if our reported metrics are a certain percentage above the baseline values, adjusted on a year to year basis, the applicable credit spread adjustments and fee rates are increased. Building in these adjustments to our credit agreement helps to show lenders we are committed to lowering our GHG emissions, but failing to meet the targets on a regular basis could be viewed negatively by such lenders. Additionally, the lending practices of institutional lenders have been the subject of intensive lobbying efforts in recent years, oftentimes public in nature, by environmental activists and others concerned about climate change not to provide funding for companies in the broader energy sector. Limitation on our access to, or increases in our cost of, capital could have a material adverse effect on us. In addition, we currently maintain non-investment grade credit ratings. As a result, we may not be able to access capital on terms (financial or otherwise) as favorable as companies that maintain investment-grade credit ratings or we may be unable to access capital at all at times when the credit markets tighten. In addition, due to our non-investment grade credit ratings, counterparties request collateral support (including cash or letters of credit) in order to enter into certain transactions with us. A downgrade in long-term debt ratings generally causes borrowing costs to increase and the potential pool of investors to shrink and could trigger liquidity demands pursuant to contractual arrangements. Future transactions by Vistra or any of its subsidiaries, including the issuance of additional debt, could result in a temporary or permanent downgrade in our credit ratings. Our indebtedness and the phaseout of LIBOR, or the replacement of LIBOR with a different reference rate, could adversely affect our ability in the future to raise additional capital to fund our operations. It could also expose us to the risk of increased interest rates and limit our ability to react to changes in the economy, or our industry, as well as impact our cash available for distribution. As of December 31, 2022, we had approximately $13.0 billion of total indebtedness and approximately $12.6 billion of indebtedness net of cash. Our debt could have negative consequences for our financial condition including: increasing our vulnerability to general economic and industry conditions; requiring a significant portion of our cash flows from operations to be dedicated to the payment of principal and interest on our indebtedness, therefore reducing our ability to pay dividends to holders of our common stock or to fund our operations, capital expenditures and future business opportunities; limiting our ability to enter into long-term power sales or fuel purchases which require credit support; limiting our ability to fund operations or future acquisitions; limiting our ability to repurchase shares under the share repurchase program; restricting our ability to make distributions or pay dividends with respect to our capital stock and the ability of our subsidiaries to make distributions to us, in light of restricted payment and other financial covenants in our credit facilities and other financing agreements; inhibiting the growth of our stock price; exposing us to the risk of increased interest rates because certain of our borrowings, including borrowings under the Vistra Operations Credit Facilities, are at variable rates of interest, only a portion of which are hedged; limiting our ability to obtain additional financing for working capital including collateral postings, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes; and limiting our ability to adjust to changing market conditions and placing us at a competitive disadvantage compared to our competitors who may have less debt. We may not be successful in obtaining additional capital for these or other reasons. Furthermore, we may be unable to refinance or replace our existing indebtedness on favorable terms or at all upon the expiration or termination thereof. Our failure to obtain additional capital or enter into new or replacement financing arrangements when due may constitute a default under such existing indebtedness and may have a material adverse effect on our business, financial condition, results of operations and cash flows. In July 2017, the United Kingdom's Financial Conduct Authority, which regulates LIBOR, announced that it intends to phase out LIBOR by the end of 2021. LIBOR is the interest rate benchmark used as a reference rate on a portion of our variable rate debt, including our revolving credit facility and interest rate swaps. In November 2020, ICE Benchmark Administration (IBA), the administrator of LIBOR, with the support of the U.S. Federal Reserve and the United Kingdom's Financial Conduct Authority, announced plans to consult on ceasing publication of USD LIBOR on December 31, 2021 for only the one-week and two-month USD LIBOR tenors, and on June 30, 2023 for all other USD LIBOR tenors. While this announcement extends the transition period to June 2023, the U.S. Federal Reserve concurrently issued a statement advising banks to stop new USD LIBOR issuances by the end of 2021. In light of these announcements, the future of LIBOR at this time is uncertain and any changes in the methods by which LIBOR is determined or regulatory activity related to LIBOR's phaseout could cause LIBOR to perform differently than in the past or cease to exist. Over the course of the last year, in anticipation of LIBOR ceasing to exist for affected tenors, we amended our revolving credit facilities to implement a change to SOFR as our primary reference rate. For our Vistra Operations Credit Agreement, we made this change in conjunction with an extension amendment. Certain lenders chose not to extend their commitments past the original maturity date. As a result, the commitments of those lenders remain subject to a LIBOR based rate. However, unless extended, those commitments, in the amount of $200 million, shall terminate on June 14, 2023 and, assuming no extension of such commitments, at such time all of our revolving credit facilities shall be SOFR based. However, our Term Loan B-3 Facility, with a December 31, 2025 maturity date, remains LIBOR-based and may be subject to the LIBOR transition risks set forth above. Further, certain of our agreements which utilize LIBOR as the referenced rate are governed by New York law, and certain of these contracts do not contain any fallback provisions or otherwise contain fallback provisions that lead to replacement rate based on LIBOR or require polling for interbank rates. To the extent that we are unsuccessful in our efforts to amend such contracts prior to the LIBOR transition, we anticipate that the applicable New York legislation would apply to such contracts and would provide a replacement rate for inclusion in such contracts. Notwithstanding our efforts, these changes may result in interest rates and/or payments that do not correlate over time with the interest rates and/or payments that would have been made on our obligations if LIBOR was available in its current form. Any new contracts would need to reference an alternative benchmark rate or include suggested fallback language. Accordingly, we could be exposed to increased costs with respect to our variable rate debt, which could have an adverse impact on extensions of our credit and/or we might not be fully hedged on the variable rate exposure on our swapped indebtedness. Any such increased costs or exposure could increase our cost of capital and have a material adverse effect on us. The agreements and instruments governing our debt, including the Vistra Operations Credit Facilities and indentures, contain restrictions and limitations that could affect our ability to operate our business, or liquidity, and results of operations, and any failure to comply with these restrictions could have a material adverse effect on us. The agreements and instruments governing our debt, including the Vistra Operations Credit Facilities and indentures, contain restrictions that could adversely affect us by limiting our ability to operate our businesses and plan for, or react to, market conditions or to meet our capital needs and could result in an event of default under the Vistra Operations Credit Facilities and/or indentures. The Vistra Operations Credit Facilities and indentures contain events of default customary for financings of this type. If we fail to comply with the covenants in the Vistra Operations Credit Facilities and/or indentures and are unable to obtain a waiver or amendment, or a default exists and is continuing, the lenders under such agreements or notes, as the case may be, could give notice and declare outstanding borrowings thereunder immediately due and payable. The breach of any covenants or obligations in certain agreements and instruments governing our debt, including the Vistra Operations Credit Facilities and indentures, not otherwise waived or amended, could result in a default under the applicable debt obligations and could trigger acceleration of those obligations, which in turn could trigger cross defaults under other agreements governing our debt, and any such acceleration of outstanding borrowings could have a material adverse effect on us. Certain of our obligations are required to be secured by letters of credit, surety bonds or cash, which increase our costs. If we are unable to provide such security, it may restrict our ability to conduct our business, which could have a material adverse effect on us. We undertake certain hedging and commodity activities and enter into certain financing arrangements with various counterparties that require cash collateral or the posting of letters of credit which are at risk of being drawn down in the event we default on our obligations. We currently use margin deposits, prepayments, surety bonds and letters of credit as credit support for commodity procurement and risk management activities. Future cash collateral requirements may increase based on the extent of our involvement in standard contracts and movements in commodity prices, and also based on our credit ratings and the general perception of creditworthiness in the markets in which we operate. In the case of commodity arrangements, the amount of such credit support that must be provided typically is based on the difference between the price of the commodity in a given contract and the market price of the commodity. Significant movements in market prices can result in our being required to provide cash collateral and letters of credit in very large amounts. The effectiveness of our strategy may be dependent on the amount of collateral available to enter into or maintain these contracts, and liquidity requirements may be greater than we anticipate or will be able to meet. Without a sufficient amount of working capital or other sources of available liquidity to post as collateral, we may not be able to manage price volatility effectively or to implement our strategy. A material increase in the amount of letters of credit or cash collateral required to be provided to our counterparties may have a material adverse effect on us. We may not be able to complete future acquisitions on favorable terms or at all, successfully integrate future acquisitions into our business, or effectively identify and invest in value-creating businesses, assets or projects, which could result in unanticipated expenses and losses or otherwise hinder or delay our growth strategy. As part of our growth strategy, including our desire to grow our retail platform, we may pursue acquisitions of assets or operating entities. This strategy depends on the Company's ability to successfully identify and evaluate acquisition opportunities and consummate acquisitions on favorable terms. Our ability to continue to implement this component of our growth strategy will be limited by our ability to identify appropriate acquisition or joint venture candidates and our financial resources, including available cash and access to capital. In addition, the Company will compete with other companies for these limited acquisition opportunities, which may increase the Company's cost of making acquisitions or limit the Companys ability to make acquisitions at all. Any expense incurred in completing acquisitions or entering into joint ventures, the time it takes to integrate an acquisition or our failure to integrate acquired businesses successfully could result in unanticipated expenses and losses. Furthermore, we may not be able to fully realize the anticipated benefits from any future acquisitions or joint ventures we may pursue. In addition, the process of integrating acquired operations into our existing operations may involve unknown risks, result in unforeseen operating difficulties and expenses, and may require significant financial resources that would otherwise be available for the execution of our business strategy. If the Company is unable to identify and consummate future acquisitions, it may impede the Company's ability to execute its growth strategy. Our ability to achieve the expected growth of our Vistra Zero portfolio, consisting of our solar generation, ESS, and other renewables development projects, is subject to substantial capital requirements and other significant uncertainties. We have a substantial capital allocation plan intended for investments in renewable assets, including solar development projects and ESSs. As part of our business strategy, we plan to continually assess potential strategic acquisitions or investments in renewable

assets, emerging technologies and related projects. Notably, the Company's ability to successfully develop our current renewables projects, or in the future acquire additional renewable assets, may be impacted by the demand for and viability of renewable assets generally, which may vary depending on availability of projects and financing, as well as public policy, financial and tax mechanisms implemented at the state and federal levels to support the development of renewable assets. Various factors could result in increased costs or result in delays or cancellation of our current or future renewable projects, or the loss of, or declines in the value of, our investments in projects including, but not limited to, risks relating to siting, financing, engineering and construction, permitting, interconnection requests, federal and state regulatory approvals, new legislation or regulatory changes impacting the industry, commissioning delays, import tariffs, changes to federal income tax laws, economic events or factors, environmental and community concerns, availability of or requirements for additional funding, enhanced competition, or the potential for termination of the power sales contract as a result of a failure to meet certain milestones. Further, the recent proliferation of renewable projects has resulted in a large volume of interconnection requests submitted to grid operators, including the markets in which we operate, resulting in significant delays to the approval process and estimated completion dates for our projects and others. Additionally, the increased demand for construction of renewables projects, such as ESSs and solar projects, and other labor market and supply chain constraints have resulted, and may continue to result, in limited availability of qualified specialists, contractors, and necessary services or materials, leading to delays in and higher costs for the development and construction of our current and future planned projects. Should any of these factors occur, our financial position, results of operations, and cash flows could be adversely affected, or our future growth opportunities may not be realized as anticipated. While certain of our subsidiaries are in various stages of developing and constructing solar generation facilities and ESSs and certain of these projects have signed long-term contracts or made similar arrangements for the sale of electricity, in other cases, our subsidiaries may enter into obligations in the development process even though the subsidiaries have not yet secured power purchase arrangements or other important elements for a successful project. If the project does not proceed as planned, our subsidiaries may remain obligated for certain liabilities even though the project will not be completed. Development is inherently uncertain and we may forgo certain development opportunities and we may undertake significant development costs before determining that we will not proceed with a particular project. We believe that capitalized costs for projects under development are recoverable; however, there can be no assurance that any individual project will be completed and reach commercial operation. If these development efforts are not successful, we may abandon a project under development and write off the costs incurred in connection with such project and could incur additional losses associated with any related contingent liabilities.
Circumstances associated with potential divestitures could adversely affect our results of operations and financial condition. In evaluating our business and the strategic fit of

our various assets, we may determine to sell one or more of such assets. Despite a decision to divest an asset, we may encounter difficulty in finding a buyer willing to purchase the asset at an acceptable price and on acceptable terms and in a timely manner. In addition, a prospective buyer may have difficulty obtaining financing. Divestitures could involve additional risks, including: difficulties in the separation of operations and personnel; the need to provide significant ongoing post-closing transition support to a buyer; management's attention may be temporarily diverted; the retention of certain current or future liabilities in order to induce a buyer to complete a divestiture; the obligation to indemnify or reimburse a buyer for certain past liabilities of a divested asset; the disruption of our business; and potential loss of key employees. We may not be successful in managing these or any other significant risks that we may encounter in divesting any asset, which could adversely affect our results of operations and financial condition. If our goodwill, intangible assets, or long-lived assets become impaired, we may be required to record a significant charge to earnings. We have significant goodwill, intangible assets and long-lived assets recorded on our balance sheet. In accordance with U.S. GAAP, goodwill and non-amortizing intangible assets are required to be tested for impairment at least annually. Additionally, we review goodwill, our intangible assets and long-lived assets for impairment when events or changes in circumstances indicate the carrying value of the asset may not be recoverable. Factors that may be considered include a decline in future cash flows, slower growth rates in the energy industry, and a sustained decrease in the price of our common stock. We performed our annual assessment of goodwill and non-amortizing intangibles in the fourth quarter of 2022 and determined that no material impairment was required. However, impairment assessments will be performed in future periods and may result in an impairment loss, which could be material. Issuances or acquisitions of our common stock, or sales or dispositions of our common stock by stockholders, that result in an ownership change as defined in Internal Revenue Code (IRC) 382 could further limit our ability to use certain tax attributes and our federal net operating losses to offset our future taxable income. If an "ownership change," as defined in Section 382 of the IRC (IRC 382) occurs, the amount of NOLs that could be used in any one year following such ownership change could be substantially limited. In general, an "ownership change" would occur when there is a greater than 50 percentage point increase in ownership of a company's stock by stockholders, each of which owns (or is deemed to own under IRC 382) 5 percent or more of such company's stock. Given IRC 382's broad definition, an ownership change could be the unintended consequence of otherwise normal market trading in our stock that is outside our control. Vistra acquired NOLs from its merger with Dynegy; however, Vistra's use of such attributes is limited under IRC 382 because the merger constituted an "ownership change" with respect to Dynegy. If there is an "ownership change" with respect to Vistra (including by the normal trading activity of greater than 5% stockholders), the utilization of all NOLs existing at that time would be subject to additional annual limitations based upon a formula provided under IRC 382 that is based on the fair market value of the Company and prevailing interest rates at the time of the ownership change. In addition, any ownership change with respect to Vistra could result in additional limitations on our ability to use certain tax attributes, including depreciation, existing at the time of any such ownership change and have an impact on our tax liabilities and on our obligations under the TRA. Tax legislation initiatives or challenges to our tax positions, or potential future legislation or the imposition of new or increased taxes or fees, could have a material adverse effect on our financial condition, results of operations and cash flows. We are subject to the tax laws and regulations of the U.S. federal, state and local governments. From time to time, legislative measures may be enacted that could adversely affect our overall tax positions regarding income or other taxes. There can be no assurance that our effective tax rate or tax payments will not be adversely affected by these legislative measures. The Tax Cuts and Jobs Act of 2017 (TCJA), enacted December 22, 2017, and the Inflation Reduction Act (IRA), enacted August 16, 2022, both introduced significant changes to current U.S. federal tax law. For example, the IRA includes the enactment of several new proposals, including, but not limited to (i) a corporate alternative minimum tax based on book income and (ii) additional requirements to qualify for enhanced renewable energy tax credits. These changes are complex and continue to be the subject of additional guidance issued by the U.S. Treasury and the Internal Revenue Service. In addition, the reaction to the federal tax changes by the individual states continues to evolve. Our interpretations and assumptions around U.S. tax reform may evolve in future periods as further administrative guidance and regulations are issued, which may materially affect our effective tax rate or tax payments. U.S. federal, state and local tax laws and regulations are extremely complex and subject to varying interpretations. There can be no assurance that our tax positions will be sustained if challenged by relevant tax authorities and if not sustained, there could be a material impact on our results of operations and financial condition. U.S. federal income tax reform and changes in other tax laws could adversely affect us. Additionally, states in which we operate or own assets may impose new or increased taxes or fees on various aspects of our operations. The passage of any legislation as a result of these proposals and other similar changes in U.S. federal income tax laws or the imposition of new or increased taxes or fees could have a material adverse effect on our financial condition, results of operations and cash flows. We are required to pay the holders of TRA Rights for certain tax benefits, which amounts could be substantial. On the Effective Date, we entered into the TRA with American Stock Transfer Trust Company, LLC, as the transfer agent. Pursuant to the TRA, we issued beneficial interests in the rights to receive payments under the TRA (TRA Rights) to the first lien creditors of our Predecessor to be held in escrow for the benefit of the first lien creditors of our Predecessor entitled to receive such TRA Rights under the Plan of Reorganization. Our financial statements reflect a liability of $522 million as of December 31, 2022 related to these future payment obligations (see Note 7 to the Financial Statements). This amount is based on certain assumptions as described more fully in the notes to the financial statements and the actual payments made under the TRA could be materially different than this estimate. The TRA generally provides for the payment by us to the holders of TRA Rights of 85% of the amount of cash savings, if any, in U.S. federal, state and local income tax that we and our subsidiaries actually realize as a result of our use of (a) the tax basis step up attributable to the PrefCo Preferred Stock Sale, (b) the entire tax basis of the assets acquired as a result of the purchase and sale agreement, dated as of November 25, 2015 by and between La Frontera Ventures, LLC and Luminant, and (c) tax benefits related to imputed interest deemed to be paid by us as a result of payments under the TRA, plus interest accruing from the due date of the applicable tax return. The amount and timing of any payments under the TRA will vary depending upon a number of factors, including the amount and timing of the taxable income we generate in the future and the tax rate then applicable, our use of loss carryovers and the portion of our payments under the TRA constituting imputed interest. Although we are not aware of any issue that would cause the IRS to challenge the tax benefits that are the subject of the TRA, recipients of the payments under the TRA will not be required to reimburse us for any payments previously made if such tax benefits are subsequently disallowed. As a result, in such circumstances, Vistra could make payments under the TRA that are greater than its actual cash tax savings. Any amount of excess payment can be used to reduce future TRA payments, but cannot be immediately recouped, which could adversely affect our liquidity. Because Vistra is a holding company with no operations of its own, its ability to make payments under the TRA is dependent on the ability of its subsidiaries to make distributions to it. To the extent that Vistra is unable to make payments under the TRA because of the inability of its subsidiaries to make distributions to us for any reason, such payments will be deferred and will accrue interest until paid, which could adversely affect our results of operations and could also affect our liquidity in periods in which such payments are made. The payments we will be required to make under the TRA could be substantial. We may be required to make an early termination payment to the holders of TRA Rights under the TRA. The TRA provides that, in the event that Vistra breaches any of its material obligations under the TRA, or upon certain mergers, asset sales, or other forms of business combination or certain other changes of control, the transfer agent under the TRA may treat such event as an early termination of the TRA, in which case Vistra would be required to make an immediate payment to the holders of the TRA Rights equal to the present value (at a discount rate equal to LIBOR plus 100 basis points) of the anticipated future tax benefits based on certain valuation assumptions. As a result, upon any such breach or change of control, we could be required to make a lump sum payment under the TRA before we realize any actual cash tax savings and such lump sum payment could be greater than our future actual cash tax savings. The aggregate amount of these accelerated payments could be materially more than our estimated liability for payments made under the TRA set forth in our financial statements, which could have a substantial negative impact on our liquidity. Regulatory and Legislative Risks Our businesses are subject to ongoing complex governmental regulations and legislation that have adversely impacted, and may in the future adversely impact, our businesses, results of operations, liquidity, financial condition and cash flows. Our businesses operate in changing market environments influenced by various state and federal legislative and regulatory initiatives regarding the restructuring of the energy industry, including competition in power generation and sale of electricity, natural gas, carbon offsets and renewable energy certificates, and other commodities. Although we attempt to comply with changing legislative and regulatory requirements, there is a risk that we will fail to adapt to any such changes successfully or on a timely basis. Compliance with, or changes to, the requirements under these legal and regulatory regimes, including those proposed or implemented under the Biden administration, may adversely impact our businesses, results of operations, liquidity, financial condition and cash flows. Our businesses are subject to numerous state and federal laws (including, but not limited to, PURA, the Federal Power Act, the Natural Gas Policy Act, the Atomic Energy Act, the Public Utility Regulatory Policies Act of 1978, the Clean Air Act (CAA), the Clean Water Act (CWA), the Resource Conservation and Recovery Act (RCRA), the Energy Policy Act of 2005, the Dodd-Frank Wall Street Reform and the Consumer Protection Act and the Telephone Consumer Protection Act), changing governmental policy and regulatory actions (including those of the FERC, the NERC, the RCT, the MSHA, the EPA, the NRC, the DOJ, the FTC, the CFTC, state public utility commissions and state environmental regulatory agencies), and the rules, guidelines and protocols of ERCOT, CAISO, ISO-NE, MISO, NYISO and PJM with respect to various matters, including, but not limited to, market structure and design, operation of nuclear generation facilities, construction and operation of other generation facilities, development, operation and reclamation of lignite mines, recovery of costs and investments, decommissioning costs, market behavior rules, present or prospective wholesale and retail competition, administrative pricing mechanisms (and adjustments thereto), rates for wholesale sales of electricity, mandatory reliability standards and environmental matters. We, along with other market participants, are subject to electricity pricing constraints and market behavior and other competition-related rules and regulations. Additionally, Ambits direct selling business (i) could be found by federal, state or foreign regulators not to be in compliance with applicable law or regulations, which may lead to our inability to obtain or maintain a license, permit, or similar certification and (ii) may be required to alter its compensation practices in order to comply with applicable federal or state law or regulations. Changes in, revisions to, or reinterpretations of, existing laws and regulations may have a material adverse effect on our businesses, results of operations, liquidity, financial condition and cash flows. Extreme weather events have resulted, and in the future may result, in efforts by both federal and state government and regulatory agencies to investigate and determine the causes of such events. For example, as a result of Winter Storm Uri, we received a civil investigative demand from the Attorney General of Texas as well as a request for information from ERCOT, NERC, and other regulatory bodies related to this event. The recent Winter Storm Elliott has also led to regulatory requests for information and notices of investigation by NERC, FERC, regional reliability entities, and independent market monitors for regions across the country. Such efforts have resulted, and in the future may result, in changes in laws or regulations that impact our industry and businesses including, but not limited to, additional requirements for winterization of various facets of the electricity supply chain including generation, transmission, and fuel supply; improvements in coordination among the various participants in the electricity supply chain during any future event; restrictions or limitations on the types of plans permitted to be offered to customers; potential revisions to the method or calculation of market compensation and incentives relating to the continued operation of assets that only run periodically, including during extreme weather events or other times of scarcity; and other potential legislative and regulatory corrective actions that may be taken. Previously announced or future legal proceedings, regulatory actions, investigations, or other administrative proceedings involving market participants may lead to adverse determinations or other findings of violations of laws, rules or regulations, any of which may impact the ability of market participants to satisfy, in whole or in part, their respective obligations. The Texas Legislature, the PUCT, and ERCOT have implemented new requirements and continue to consider future market design and other rule changes in response to Winter Storm Uri and other extreme weather events. Finally, the regulatory environment has undergone significant changes in the last several years due to state and federal policies affecting wholesale and retail competition and the creation of incentives for the addition of large amounts of new renewable generation. For example, changes to, or development of, legislation that requires the use of clean renewable and alternate fuel sources or mandate the implementation of energy conservation programs that require the implementation of new technologies, could increase our capital expenditures and/or impact our financial condition. Additionally, in some retail energy markets, state legislators, government agencies and other interested parties have made proposals to change the use of market-based pricing, re-regulate areas of these markets that have previously been competitive, or permit electricity delivery companies to construct or acquire generating facilities. Other proposals to re-regulate the retail energy industry may be made, and legislative or other actions affecting electricity and natural gas deregulation or restructuring process may be delayed, discontinued or reversed in states in which we currently operate or may in the future operate. If such changes were to be enacted by a regulatory body, we may lose customers, incur higher costs and/or find it more difficult to acquire new customers. These changes are ongoing, and we cannot predict the future design of the wholesale power markets or the ultimate effect that the changing regulatory environment will have on our business. We are required to obtain, and to comply with, government permits and approvals. We are required to obtain, and to comply with, numerous permits and licenses from federal, state and local governmental agencies. The process of obtaining and renewing necessary permits and licenses can be lengthy and complex and can sometimes result in the establishment of conditions that make the project or activity for which the permit or license was sought unprofitable or otherwise unattractive. In addition, such permits or licenses may be subject to denial, revocation or modification under various circumstances. Failure to obtain or comply with the conditions of permits or licenses, or failure to comply with applicable laws or regulations, may result in the delay or temporary suspension of our operations and electricity sales or the curtailment of our delivery of electricity to our customers and may subject us to penalties and other sanctions. Although various regulators routinely renew existing permits and licenses, renewal of our existing permits or licenses could be denied or jeopardized by various factors, including (a) failure to provide adequate financial assurance for closure, (b) failure to comply with environmental, health and safety laws and regulations or permit conditions, (c) local community, political or other opposition and (d) executive, legislative or regulatory action. Our inability to procure and comply with the permits and licenses required for our operations, or the cost to us of such procurement or compliance, could have a material adverse effect on us. In addition, new environmental legislation or regulations, if enacted, or changed interpretations of existing laws, may cause activities at our facilities to need to be changed to avoid violating applicable laws and regulations or elicit claims that historical activities at our facilities violated applicable laws and regulations. In addition to the possible imposition of fines in the case of any such violations, we may be required to undertake significant capital investments and obtain additional operating permits or licenses, which could have a material adverse effect on us. Our cost of compliance with existing and new environmental laws could have a material adverse effect on us. We are subject to extensive environmental regulation by governmental authorities, including federal and state environmental agencies and/or attorneys general. We may incur significant additional costs beyond those currently contemplated to comply with these regulatory requirements. If we fail to comply with these regulatory requirements, we could be subject to administrative, civil or criminal liabilities and fines. Existing environmental regulations could be revised or reinterpreted, new laws and regulations could be adopted or become applicable to us or our facilities, and future changes in environmental laws and regulations could occur, including potential regulatory and enforcement developments related to air emissions and CCR, all of which could result in significant additional costs beyond those currently contemplated to comply with existing requirements. Any of the foregoing could have a material adverse effect on us. The EPA has recently finalized or proposed several regulatory actions establishing new requirements for control of certain emissions from sources, including electricity generation facilities. In the future, the EPA may also propose and finalize additional regulatory actions that may adversely affect our existing generation facilities or our ability to cost-effectively develop new generation facilities. There is no assurance that the currently installed emissions control equipment at our lignite, coal and/or natural gas-fueled generation facilities will satisfy the requirements under any future EPA or state environmental regulations. Some of the recent regulatory actions, such as the EPA's proposed Cross-State Air Pollution Rule Update, the ACE rule and any proposed or future actions to replace the ACE rule, and actions under the Regional Haze program, could require us to install significant additional control equipment, resulting in potentially material costs of compliance for our generation units, including capital expenditures, higher operating and fuel costs and potential production curtailments or plant retirements. These costs or operation impacts could have a material adverse effect on us. We may not be able to obtain or maintain all required environmental regulatory approvals. If there is a delay in obtaining any required environmental regulatory approvals, if we fail to obtain, maintain or comply with any such approval or if an approval is retroactively disallowed or adversely modified, the operation of our generation facilities could be stopped, disrupted, curtailed or modified or become subject to additional costs. Any such stoppage, disruption, curtailment, modification or additional costs could have a material adverse effect on us. In addition, we may be responsible for any on-site liabilities associated with the environmental condition of facilities that we have acquired, leased, developed or sold, regardless of when the liabilities arose and whether they are now known or unknown. In connection with certain acquisitions and sales of assets, we may obtain, or be required to provide, indemnification against certain environmental liabilities. Another party could, depending on the circumstances, assert an environmental claim against us or fail to meet its indemnification obligations to us, which could have a material adverse effect on us. We could be materially and adversely affected if new federal or state legislation or regulations are adopted to address global climate change that could require efforts that exceed or are more expensive than our currently planned initiatives or if we are subject to lawsuits for alleged damage to persons or property resulting from greenhouse gas emissions. There is attention and interest nationally and internationally about global climate change and how GHG emissions, such as CO_2, contribute to global climate change. Over the last several years, the U.S. Congress has considered and debated several proposals intended to address climate change using different approaches, including a cap on carbon emissions with emitters allowed to trade unused emission allowances (cap-and-trade), a tax on carbon or GHG emissions, incentives for the development of low-carbon technology and federal renewable portfolio standards. In July 2019, the EPA finalized the ACE rule that developed emissions guidelines that states must use when developing plans to regulate GHG emissions from existing coal-fueled electric generating units. In January 2021, the ACE rule was vacated by the D.C. Circuit Court and remanded to the EPA for further consideration in accordance with the court's ruling. The D.C. Circuit Court's decision was appealed to the U.S. Supreme Court. In June 2022, the U.S. Supreme Court issued its decision in West Virginia v. EPA , in which it held that the EPA does not have the authority to apply generation shifting in the regulation of GHG emissions. The judgment reversed the D.C. Circuit Court's decision and remanded the case for further proceedings consistent with the U.S. Supreme Court's opinion. The EPA may develop a more stringent and more encompassing rule to replace the ACE rule in its remand proceeding and has been directed by the Biden Administration to review this rule and others promulgated by the EPA during the Trump Administration. Prior to the vacatur and remand by the D.C. Circuit Court, states where we operate coal plants (Texas, Illinois and Ohio) had begun the development of their state plans to comply with the ACE rule. In addition, a number of federal court cases have been filed in recent years asserting damage claims related to GHG emissions, and the results in those proceedings could establish adverse precedent that might apply to companies (including us) that produce GHG emissions. We could be materially and adversely affected if new federal and/or state legislation or regulations are adopted to address global climate change that could require efforts that exceed or are more expensive than our currently planned initiatives or if we are subject to lawsuits for alleged damage to persons or property resulting from GHG emissions. Additionally, in January 2021, President Biden issued written notification to the United Nations of the U.S.'s intention to rejoin the Paris Agreement, effective in February 2021. Although the Paris Agreement does not create any binding obligations for nations to limit their GHG emissions, it does include pledges to voluntarily limit or reduce future emissions, and various corporations, investors and U.S. states and local governments have previously pledged to further the goals of the Paris Agreement. Additionally, the Biden Administration has directed certain agencies to submit a plan to the National Climate Task Force to achieve a carbon-pollution-free electricity sector by 2035. The Company's plan to transition to clean power generation sources and reduce its GHG emissions may not be completed in this timeframe and we may not otherwise achieve our sustainability and emissions reduction targets as expected. Accordingly, we may be required to accelerate or change our targets, incur additional expenses, and/or adjust or cease certain operations as a result of newly implemented federal and/or state regulations to reduce future carbon emissions. Luminant's mining operations are subject to RCT oversight. We currently own and operate, or are in the process of reclaiming, various surface lignite coal mines in Texas to provide fuel for our electricity generation facilities. We also own or lease, and are in the process of reclaiming, multiple waste-to-energy surface facilities in Pennsylvania. The RCT, which exercises broad authority to regulate reclamation activity, reviews on an ongoing basis whether Luminant is compliant with RCT rules and regulations and whether it has met all the requirements of its mining permits in Texas. Any new rules and regulations adopted by the RCT or the Department of Interior Office of Surface Mining, which also regulates mining activity nationwide, or any changes in the interpretation of existing rules and regulations, could result in higher compliance costs or otherwise adversely affect our financial condition or cause a revocation of a mining permit. Any revocation of a mining permit would mean that Luminant would no longer be allowed to mine lignite at the applicable mine to serve its generation facilities. Luminant's lignite mining reclamation activity will require significant resources as existing and retired mining operations are reclaimed over the next several years. In conjunction with Luminant's announcements in 2017 to retire several power generation assets and related mining operations, along with the continuous reclamation activity at its continuing mining operations for its mines related to the Oak Grove generation asset, Luminant is expected to spend a significant amount of money, internal resources and time to complete the required reclamation activities. For the next five years, Vistra is projected to spend approximately $234 million (on a nominal basis) to achieve its mining reclamation objectives. Litigation, legal proceedings, regulatory investigations or other administrative proceedings could expose us to significant liabilities and reputational damage that could have a material adverse effect on us. We are involved in the ordinary course of business in a number of lawsuits involving, among other matters, employment, commercial, and environmental issues, and other claims for injuries and damages. We evaluate litigation claims and legal proceedings to assess the likelihood of unfavorable outcomes and to estimate, if possible, the amount of potential losses. Based on these evaluations and estimates, when required by applicable accounting rules, we establish reserves and disclose the relevant litigation claims or legal proceedings, as appropriate. These evaluations and estimates are based on the information available to management at the time and involve a significant amount of judgment. Actual outcomes or losses may differ materially from current evaluations and estimates. The settlement or resolution of such claims or proceedings may have a material adverse effect on us. We use appropriate means to contest litigation threatened or filed against us, but the litigation environment poses a significant business risk. We are also involved in the ordinary course of business in regulatory investigations and other administrative proceedings, and we are exposed to the risk that we may become the subject of additional regulatory investigations or administrative proceedings. While we cannot predict the outcome of any regulatory investigation or administrative proceeding, any such regulatory investigation or administrative proceeding could result in us incurring material penalties and/or other costs and have a materially adverse effect on us. Our retail businesses, which each have REP certifications that are subject to review of the public utility commissions in the states in which we operate, are subject to changing state rules and regulations that could have a material impact on the profitability of our business. The competitiveness of our U.S. retail businesses partially depends on state regulatory policies that establish the structure, rules, terms and conditions on which services are offered to retail customers. Specifically, the public utility commissions and/or the attorney generals of the various jurisdictions in which the Retail segment operates may at any time initiate an investigation into whether our retail operations comply with certain commission rules or state laws and whether we have met the requirements for REP certification, including financial requirements. These state policies and investigations, which can include controls on the retail rates our retail businesses can charge, the imposition of additional costs on sales, restrictions on our ability to obtain new customers through various marketing channels and disclosure requirements, investigations into whether our retail operations comply with certain commission rules or state laws and whether we have met the requirements for REP certification, including financial requirements, can affect the competitiveness of our retail businesses. Any removal or revocation of a REP certification would mean that we would no longer be allowed to provide electricity service to retail customers in the applicable jurisdiction, and such decertification could have a material adverse effect on us. Additionally, state or federal imposition of net metering or renewable portfolio standard programs can make it more or less expensive for retail customers to supplement or replace their reliance on grid power. Our retail businesses may have limited ability to influence development of these state rules, regulations and policies, and our business model may be more or less effective, depending on changes to the regulatory environment. Operational Risks Volatile power supply costs and demand for power have and could in the future adversely affect the financial performance of our retail businesses. Although we are the primary provider of our retail businesses' wholesale electricity supply requirements, our retail businesses purchase a portion of their supply requirements from third parties. As a result, the financial performance of our retail business depends on their ability to obtain adequate supplies of electric generation from third parties at prices below the prices they charge their customers. Consequently, our earnings and cash flows could be adversely affected in any period in which the retail businesses' wholesale electricity supply costs rise at a greater rate than the rates they charge to customers. The price of wholesale electricity supply purchases associated with the retail businesses' energy commitments can be different than that reflected in the rates charged to customers due to, among other factors: varying supply procurement contracts used and the timing of entering into related contracts; subsequent changes in the overall price of natural gas; daily, monthly or seasonal fluctuations in the price of natural gas relative to the 12-month forward prices; transmission constraints and the Company's ability to move power to our customers; out-of-market payments, uplifts, or other non-pass through charges, and changes in market heat rate. The retail businesses' earnings and cash flows could also be adversely affected in any period in which their customers' actual usage of electricity significantly varies from the forecasted usage, which could occur due to, among other factors, weather events, transmission and distribution outages, demand-side management programs, competition and economic conditions, such as Winter Storm Uri in February 2021. Our retail operations are subject to significant competition from other REPs, which could result in a loss of existing customers and the inability to attract new customers. We operate in a very competitive retail market and, as a result, our retail operation faces significant competition for customers. We believe our brands are viewed favorably in the retail electricity markets in which we operate, but despite our commitment to providing superior customer service and innovative products, customer sentiment toward our brands, including by comparison to our competitors' brands, depends on certain factors beyond our control. For example, competitor REPs may offer different products, lower electricity prices and other incentives, which, despite our long-standing relationship with many customers, may attract customers away from us. If we are unable to successfully compete with competitors in the retail market it is possible our retail customer counts could decline, which could have a material adverse effect on us. As we try to grow our retail business and operate our business strategy, we compete with various other REPs that may have certain advantages over us. For example, in new markets, our principal competitor for new customers may be the incumbent REP, which has the advantage of long-standing relationships with its customers, including well-known brand recognition. In addition to competition from the incumbent REP, we may face competition from a number of other energy service providers, other energy industry participants, or nationally branded providers of consumer products and services who may develop businesses that will compete with us. Some of these competitors or potential competitors may be larger than we are or have greater resources or access to capital than we have. If there is inadequate potential margin in retail electricity markets with substantial competition to overcome the adverse effect of relatively high customer acquisition costs in such markets, it may not be profitable for us to compete in these markets. Our retail operations rely on the infrastructure of local utilities or independent transmission system operators to provide electricity to, and to obtain information about, our customers. Any infrastructure failure could negatively impact customer satisfaction and could have a material adverse effect on us. The substantial majority of our retail operations depend on transmission and distribution facilities owned and operated by unaffiliated utilities to deliver the electricity that we sell to our customers. If transmission capacity is inadequate, our ability to sell and deliver electricity may be hindered and we may have to forgo sales or buy more expensive wholesale electricity than is available in the capacity-constrained area or, with respect to capacity performance in PJM and performance incentives in ISO-NE, we may be subject to significant penalties. For example, during some periods, transmission access is constrained in some areas of the Dallas-Fort Worth metroplex, where we have a significant number of customers. The cost to provide service to these customers may exceed the cost to provide service to other customers, resulting in lower operating margins. In addition, any infrastructure failure that interrupts or impairs delivery of electricity to our customers could negatively impact customer satisfaction with our service. Any of the foregoing could have a material adverse effect on us. The operation of our businesses is subject to advanced persistent cyber-based security threats and integrity risk. Attacks on our infrastructure that breach cyber/data security measures could expose us to significant liabilities, reputational damage, regulatory action, and disrupt business operations, which could have a material adverse effect on us. Numerous functions affecting the efficient operation of our businesses are dependent on the secure and reliable storage, processing and communication of electronic data and the use of sophisticated computer hardware and software systems and much of our information technology infrastructure is connected (directly or indirectly) to the internet. Our information technology systems and infrastructure, and those of our vendors and suppliers, are susceptible to threats which could compromise confidentiality, integrity or availability. While we have controls in place designed to protect our infrastructure, such breaches and threats are becoming increasingly sophisticated and complex, requiring continuing evolution of our program. Any such breach, disruption or similar event that impairs our information technology infrastructure could disrupt normal business operations and affect our ability to control our generation assets, maintain confidentiality, availability and integrity of our restricted data, access retail customer information and limit communication with third parties, which could have a material adverse effect on us. As part of the continuing development of new and modified reliability standards, the FERC has approved changes to its Critical

Infrastructure Protection reliability standards and has established standards for assets identified as "critical cyber assets." Under the Energy Policy Act of 2005, the FERC can impose penalties (up to $1 million per day, per violation) for failure to comply with mandatory electric reliability standards, including standards to protect the power system against potential disruptions from cyber/data and physical security breaches. Further, our retail business requires us to access, collect, store and transmit sensitive customer data in the ordinary course of business. Concerns about data privacy and data protection have led to increased regulation and other actions that could impact our businesses and changes in data privacy and data protection laws and regulations or any failure to comply with such laws and regulations could adversely affect our business and financial results. Our retail business may need to provide sensitive customer data to vendors and service providers who require access to this information in order to provide services, such as call center operations, to the retail business. Although we take precautions to protect our infrastructure, we have been, and will likely continue to be, subject to attempts at phishing and other cybersecurity intrusions. International conflict increases the risk of state-sponsored cyber threats and escalated use of cybercriminal and cyber-espionage activities. In particular, the current geopolitical climate has further escalated cybersecurity risk, with various government agencies, including the U.S. Cybersecurity Infrastructure Security Agency, issuing warnings of increased cyber threats, particularly for U.S. critical infrastructure. While the Company has not experienced a cyber/data event causing any material operational, reputational or financial impact, we recognize the growing threat within the general marketplace and our industry, and there is no assurance that we will be able to prevent any such impacts in the future. If a material breach of our information technology systems were to occur, the critical operational capabilities and reputation of our business may be adversely affected, customer confidence may be diminished, and our business may be subject to substantial legal or regulatory scrutiny and claims, any of which may contribute to potential legal or regulatory actions against the Company, loss of customers and otherwise have a material adverse effect on us. Any loss or disruption of critical operational capabilities to support our generation, commercial or retail operations, loss of customers, or loss of confidential or proprietary data through a breach, unauthorized access, disruption, misuse or disclosure could adversely affect our reputation, expose us to material legal or regulatory claims and impair our ability to execute our business strategy, which could have a material adverse effect on us. In addition, we may experience increased capital and operating costs to implement increased security for our information technology infrastructure. We cannot provide any assurance that such events and impacts will not be material in the future, and our efforts to deter, identify and mitigate future breaches may require additional significant capital and may not be successful. We may suffer material losses, costs and liabilities due to operation risks, regulatory risks, and the risk of nuclear accidents arising from the ownership and operation of the Comanche Peak nuclear generation facility. We own and operate a nuclear generation facility in Glen Rose, Texas (Comanche Peak Facility). The ownership and operation of a nuclear generation facility involves certain risks. These risks include: unscheduled outages or unexpected costs due to equipment, mechanical, structural, cybersecurity, insider threat, third-party compromise or other problems; inadequacy or lapses in maintenance protocols; the impairment of reactor operation and safety systems due to human error or force majeure; the costs of, and liabilities relating to, storage, handling, treatment, transport, release, use and disposal of radioactive materials; the costs of procuring nuclear fuel, including impacts from restrictions on imports from Russia or China; the costs of storing and maintaining spent nuclear fuel at our on-site dry cask storage facility; terrorist or cybersecurity attacks by nation-states or other threat actors and the cost to protect and recover against any such attack; the impact of a natural disaster; limitations on the amounts and types of insurance coverage commercially available; and uncertainties with respect to the technological and financial aspects of modifying or decommissioning nuclear facilities at the end of their useful lives. Any prolonged unavailability of the Comanche Peak Facility could have a material adverse effect on our results of operation, cash flows, financial position and reputation. The following are among the more significant related risks: Operational Risk Operations at any generation facility could degrade to the point where the facility would have to be shut down. If such degradations were to occur at the Comanche Peak Facility, the process of identifying and correcting the causes of the operational downgrade to return the facility to operation could require significant time and expense, resulting in both lost revenue and increased fuel and purchased power expense to meet supply commitments. Furthermore, a shut-down or failure at any other nuclear generation facility could cause regulators to require a shut-down or reduced availability at the Comanche Peak Facility. Regulatory Risk The NRC may modify, suspend or revoke licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under it or the terms of the licenses of nuclear generation facilities. Unless extended, as to which no assurance can be given, the NRC operating licenses for the two licensed operating units at the Comanche Peak Facility will expire in 2030 and 2033, respectively. Changes in regulations by the NRC, as well as any extension of our operating licenses, could require a substantial increase in capital expenditures or result in increased operating or decommissioning costs. Nuclear Accident Risk Although the safety record of the Comanche Peak Facility and other nuclear generation facilities generally has been very good, accidents and other unforeseen problems have occurred both in the U.S. and elsewhere. The consequences of an accident can be severe and include loss of life, injury, lasting negative health impacts and property damage. Any accident, or perceived accident, could result in significant liabilities and damage our reputation. Any such resulting liability from a nuclear accident could exceed our resources, including insurance coverage, and could ultimately result in the suspension or termination of power generation from the Comanche Peak Facility. The operation and maintenance of power generation facilities and related mining operations are capital intensive and involve significant risks that could adversely affect our results of operations, liquidity and financial condition. The operation and maintenance of power generation facilities and related mining operations involve many risks, including, as applicable, start-up risks, breakdown or failure of facilities, equipment or processes, operator error, lack of sufficient capital to maintain the facilities, the dependence on a specific fuel source, the ability to timely obtain parts for equipment repairs, the inability to transport our product to our customers in an efficient manner due to the lack of transmission capacity or the impact of unusual or adverse weather conditions or other natural events, or terrorist attacks, as well as the risk of performance below expected levels of output, efficiency or reliability, the occurrence of any of which could result in substantial lost revenues and/or increased expenses. A significant number of our facilities were constructed many years ago. Older generating equipment, even if maintained or refurbished in accordance with good engineering practices, may require significant capital expenditures to operate at peak efficiency or reliability. The risk of increased maintenance and capital expenditures arises from (a) increased starting and stopping of generation equipment due to the volatility of the competitive generation market and the prospect of continuing low wholesale electricity prices that may not justify sustained or year-round operation of all our generation facilities, (b) any unexpected failure to generate power, including failure caused by equipment breakdown or unplanned outage (whether by order of applicable governmental regulatory authorities, the impact of weather events or natural disasters or otherwise), (c) damage to facilities due to storms, natural disasters, wars, terrorist or cyber/data security acts, including nation-state attacks or organized cyber and other catastrophic events and (d) the passage of time and normal wear and tear. Further, our ability to successfully and timely complete routine maintenance or other capital projects at our existing facilities is contingent upon many variables and subject to substantial risks. Should any such efforts be unsuccessful, we could be subject to additional costs or losses and write downs of our investment in the project. We cannot be certain of the level of capital expenditures that will be required due to changing environmental and safety laws and regulations (including changes in the interpretation or enforcement thereof), needed facility repairs and unexpected events (such as environmental impacts, natural disasters or terrorist or cyber/data security attacks). The unexpected requirement of large capital expenditures could have a material adverse effect on us. Moreover, if we significantly modify a unit, we may be required to install the best available control technology or to achieve the lowest achievable emission rates as such terms are defined under the new source review provisions of the CAA, which would likely result in substantial additional capital expenditures. In addition, unplanned outages at any of our generation facilities, whether because of equipment breakdown or otherwise, typically increase our operation and maintenance expenses and may reduce our revenues as a result of selling fewer MWh or non-performance penalties or require us to incur significant costs as a result of running one of our higher cost units or to procure replacement power at spot market prices in order to fulfill contractual commitments. If we do not have adequate liquidity to meet margin and collateral requirements, we may be exposed to significant losses, may miss significant opportunities and may have increased exposure to the volatility of spot markets, which could have a material adverse effect on us. Further, our inability to operate our generation facilities efficiently, manage capital expenditures and costs, and generate earnings and cash flows from our asset-based businesses could have a material adverse effect on our results of operations, financial condition or cash flows. While we maintain insurance, obtain warranties from vendors and obligate contractors to meet certain performance levels, the proceeds of such insurance, warranties or performance guarantees may not be adequate to cover our lost revenues, increased expenses or liquidated damages payments should we experience equipment breakdown or non-performance by contractors or vendors. Operation of power generation facilities involves significant risks and hazards customary to the power industry that could have a material adverse effect on our revenues and results of operations, and we may not have adequate insurance to cover these risks and hazards. Our employees, contractors, customers and the general public may be exposed to a risk of injury due to the nature of our operations. Power generation involves hazardous activities, including acquiring, transporting and unloading fuel, operating large pieces of equipment and delivering electricity to transmission and distribution systems. In addition to natural risks such as extreme weather, earthquake, flood, lightning, hurricane and wind, other human-made hazards, such as nuclear accidents, dam failure, gas or other explosions, mine area collapses, fire, structural collapse, machinery failure and other dangerous incidents are inherent risks in our operations. These and other hazards can cause significant personal injury or loss of life, severe damage to and destruction of property, plant and equipment, contamination of, or damage to, the environment and suspension of operations. Further, our employees and contractors work in, and customers and the general public may be exposed to, potentially dangerous environments at or near our operations. As a result, employees, contractors, customers and the general public are at risk for serious injury, including loss of life. The occurrence of any one of these events may result in us being named as a defendant in lawsuits asserting claims for substantial damages, including for environmental cleanup costs, personal injury and property damage and fines and/or penalties. We maintain an amount of insurance protection that we consider adequate, but we cannot provide any assurance that our insurance will be sufficient or effective under all circumstances and against all hazards or liabilities to which we may be subject and, even if we do have insurance coverage for a particular circumstance, we may be subject to a large deductible and maximum cap. A successful claim for which we are not fully insured could hurt our financial results and materially harm our financial condition. Further, due to rising insurance costs and changes in the insurance markets, including increasing pressure on firms that provide insurance to companies that own and operate fossil fuel generation, we cannot provide any assurance that our insurance coverage will continue to be available at all or at rates or on terms similar to those presently available. Any losses not covered by insurance could have a material adverse effect on our financial condition, results of operations or cash flows. We have been and may in the future be materially and adversely affected by obligations to comply with federal and state regulations, laws, and other legal requirements that govern the operations, assessments, storage, closure, corrective action, disposal and monitoring relating to CCR. As a result of electricity produced for decades at coal-fueled power plants in Illinois, Texas and Ohio, we manage large amounts of CCR material in surface impoundments. In addition to the federal requirements under the CCR rule, CCR surface impoundments will continue to be regulated by existing state laws, regulations and permits, as well as additional legal requirements that may be imposed in the future. These federal and state laws, regulations and other legal requirements may require or result in additional expenditures, increased operating and maintenance costs and/or result in closure of certain power generating facilities, which could affect the results of operations, financial position and cash flows of the Company. We have recognized ARO related to these CCR-related requirements. As the closure and CCR management work progresses and final closure plans and corrective action measures are developed and approved at each site, the scope and complexity of work and the amount of CCR material could be greater than current estimates and could, therefore, materially impact earnings through increased compliance expenditures. The EPA has been directed by the Biden Administration to review a number of environmental rules adopted by the EPA during the Trump Administration, including the CCR rule, the ELG rule, the ACE rule and the particulate matter (PM) and NAAQS rules. All of these rules may significantly and adversely impact our existing coal fleet and may lead to accelerated plant closure timeframes. In addition, the expected replacement to the ACE rule and NAAQS also have the potential to adversely impact our gas-fired units. The EPA is reviewing applications submitted by us to extend closure deadlines for many of our CCR impoundments. The scope and cost of that closure work could increase significantly based on new or potential requirements imposed by the EPA or state agencies, including the EPA's interpretations on requirements for closure of CCR units. There is no assurance that our current assumptions for closure activities will be accepted by the EPA. If ponds must be closed sooner than anticipated, plant closures timeframes may be accelerated. The availability and cost of emission allowances could adversely impact our costs of operations. We are required to maintain, through either allocations or purchases, sufficient emission allowances for SO_2, CO_2 and NO_X to support our operations in the ordinary course of operating our power generation facilities. These allowances are used to meet the obligations imposed on us by various applicable environmental laws. If our operational needs require more than our allocated allowances, we may be forced to purchase such allowances on the open market, which could be costly. If we are unable to maintain sufficient emission allowances to match our operational needs, we may have to curtail our operations so as not to exceed our available emission allowances or install costly new emission controls. As we use the emission allowances that we have purchased on the open market, costs associated with such purchases will be recognized as operating expense. If such allowances are available for purchase, but only at significantly higher prices, the purchase of such allowances could materially increase our costs of operations in the affected markets.

We have been and may in the future be materially and adversely affected by the effects of extreme weather conditions and seasonality. We have been and may in the future be materially affected by weather conditions and our businesses may fluctuate substantially on a seasonal basis as the weather changes. In addition, we are subject to the effects of extreme weather conditions, including sustained or extreme cold or hot temperatures, hurricanes, floods, droughts, storms, fires, earthquakes or other natural disasters, which could stress our generation facilities and grid reliability, limit our ability to procure adequate fuel supply, or result in outages, damage or destroy our assets and result in casualty losses that are not ultimately offset by insurance proceeds, and could require increased capital expenditures or maintenance costs, including supply chain costs. Moreover, an extreme weather event could cause disruption in service to customers due to downed wires and poles or damage to other operating equipment, which could result in us foregoing sales of electricity and lost revenue. Similarly, certain extreme weather events have previously affected, and may in the future, affect, the availability of generation and transmission capacity, limiting our ability to source or deliver power where it is needed or limit our ability to source fuel for our plants, including due to damage to rail or natural gas pipeline infrastructure. Additionally, extreme weather has resulted, and may in the future result, in (i) unexpected increases in customer load, requiring our retail operation to procure additional electricity supplies at wholesale prices in excess of customer sales prices for electricity, (ii) the failure of equipment at our generation facilities, (iii) a decrease in the availability of, or increases in the cost of, fuel sources, including natural gas, diesel and coal, or (iv) unpredictable curtailment of customer load by the applicable ISO/RTO in order to maintain grid reliability, resulting in the realization of lower wholesale prices or retail customer sales. For example, Winter Storm Uri in February 2021 had a material impact on our results of operations. Additionally, climate change may produce changes in weather or other environmental conditions, including temperature or precipitation levels, and thus may impact consumer demand for electricity. In addition, the potential physical effects of climate change, such as increased frequency and severity of storms, floods, and other climatic events, could disrupt our operations and cause us to incur significant costs to prepare for or respond to these effects. Weather conditions, which cannot be reliably predicted, could have adverse consequences by requiring us to seek additional sources of electricity when wholesale market prices are high or to sell excess electricity when market prices are low, as well as significantly limiting the supply of, or increasing the cost of our fuel supply, each of which could have a material adverse effect on our business, results of operations, financial condition and liquidity. Events outside of our control, including an epidemic or outbreak of an infectious disease, such as COVID-19, may materially adversely affect our business. We face risks related to epidemics, outbreaks or other public health events that are outside of our control, and could significantly disrupt our operations and adversely affect our financial condition. The global or national outbreak of an illness or other communicable disease, or any other public health crisis, such as COVID-19, may cause disruptions to our business and operational plans, as a result of a number of factors, including (a) a protracted slowdown of broad sectors of the economy, (b) changes in demand or supply for commodities, (c) significant changes in legislation or regulatory policy to address the pandemic (including prohibitions on certain marketing channels, moratoriums or conditions on disconnections or limits or restrictions on late fees), (d) reduced demand for electricity (particularly from commercial and industrial customers), (e) increased late or uncollectible customer payments, (f) negative impacts on the health of our workforce, (g) a deterioration of our ability to ensure business continuity (including increased vulnerability to cyber and other information technology risks as a result of a significant portion of our workforce continuing to work from home), and (h) the inability of the Company's contractors, suppliers, and other business partners to fulfill their contractual obligations. Changes in technology, increased electricity conservation efforts, or energy sustainability efforts may reduce the value of our generation facilities and may otherwise have a material adverse effect on us. Technological advances have improved, and are likely to continue to improve, for existing and alternative methods to produce and store power, including gas turbines, wind turbines, fuel cells, hydrogen, micro turbines, photovoltaic (solar) cells, batteries and concentrated solar thermal devices, along with improvements in traditional technologies. Such technological advances may be superior to, or may not be compatible with, some of our existing technologies, investments and infrastructure, and may require us to make significant expenditures to remain competitive, and have resulted, and are expected to continue to reduce the costs of power production or storage, which may result in the obsolescence of certain of our operating assets. Consequently, the value of our more traditional generation assets could be significantly reduced as a result of these competitive advances, which could have a material adverse effect on us and our future success will depend, in part, on our ability to anticipate and successfully adapt to technological changes, to offer services and products that meet customer demands and evolving industry standards. In addition, changes in technology have altered, and are expected to continue to alter, the channels through which retail customers buy electricity (i.e. , self-generation or distributed-generation facilities). To the extent self-generation or distributed generation facilities become a more cost-effective option for customers, our financial condition, operating cash flows and results of operations could be materially and adversely affected. Technological advances in demand-side management and increased conservation efforts have resulted, and are expected to continue to result, in a decrease in electricity demand. A significant decrease in electricity demand as a result of such efforts would significantly reduce the value of our generation assets. Certain regulatory and legislative bodies have introduced or are considering requirements and/or incentives to reduce power consumption. Effective power conservation by our customers could result in reduced electricity demand or significantly slow the growth in such demand. Any such reduction in demand could have a material adverse effect on us. Furthermore, we may incur increased capital expenditures if we are required to increase investment in conservation measures. Additionally, increased governmental and consumer focus on energy sustainability efforts, including desire for, or incentives related to, the development, implementation and usage of low-carbon technology, may result in decreased demand for the traditional generation technologies that we currently own and operate. We may potentially be affected by emerging technologies that may over time affect change in capacity markets and the energy industry overall including distributed generation and clean technology. Some of these emerging technologies are shale gas production, distributed renewable energy technologies, energy efficiency, broad consumer adoption of electric vehicles, distributed generation and energy storage devices. Additionally, large-scale cryptocurrency mining is becoming increasingly prevalent in certain markets, including ERCOT, and many of these cryptocurrency mining facilities are "behind-the-meter." Such emerging technologies could affect the price of energy, levels of customer-owned generation, customer expectations and current business models and make portions of our electric system power supply and transmission and/or distribution facilities obsolete prior to the end of their useful lives. These emerging technologies may also affect the financial viability of utility counterparties and could have significant impacts on wholesale market prices, which could ultimately have a material adverse effect on our financial condition, results of operations and cash flows could be materially adversely affected. The loss of the services of our key management and personnel could adversely affect our ability to successfully operate our businesses. Our future success will depend on our ability to continue to attract and retain highly qualified personnel. We compete for such personnel with many other companies, in and outside of our industry, government entities and other organizations. We may not be successful in retaining current personnel or in hiring or retaining qualified personnel in the future. Further, we are facing an increasingly competitive market for hiring and retaining skilled employees in certain skill areas, which is exacerbated by the effects of the COVID-19 pandemic and increased acceptance of hiring remote working employees by our competitors and other companies. Difficulties in attracting and retaining highly qualified skilled employees may restrict our ability to adequately support our business needs and/or result in increased personnel costs. In addition, effective succession planning is important to our long-term success. Failure to timely and effectively ensure transfer of knowledge and smooth transitions involving senior management and other key personnel could hinder our strategic planning and execution. We could be materially and adversely impacted by strikes or work stoppages by our unionized employees. As of December 31, 2022, we had approximately 1,295 employees covered by collective bargaining agreements. The terms of all current collective bargaining agreements covering represented personnel engaged in lignite mining operations, lignite-, coal-, natural gas- and nuclear-fueled generation operation, as well as some battery operations, expire on various dates between March 2023 and August 2025, but remain effective thereafter unless and until terminated by either party. In the event that our union employees strike, participate in a work stoppage or slowdown or engage in other forms of labor strife or disruption, we would be responsible for procuring replacement labor or we could experience reduced power generation or outages. We have in place strike contingency plans that address the procurement of replacement labor. Strikes, work stoppages or the inability to negotiate current or future collective bargaining agreements on favorable terms or at all could have a material adverse effect on us. Risks Related to Our Structure and Ownership of our Common Stock Vistra is a holding company and its ability to obtain funds from its subsidiaries is structurally subordinated to existing and future liabilities of its subsidiaries. Vistra is a holding company that does not conduct any business operations of its own. As a result, Vistra's cash flows and ability to meet its obligations are largely dependent upon the operating cash flows of Vistra's subsidiaries and the payment of such operating cash flows to Vistra in the form of dividends, distributions, loans or otherwise. These subsidiaries are separate and distinct legal entities from Vistra and have no obligation (other than any existing contractual obligations) to provide Vistra with funds to satisfy its obligations. Any decision by a subsidiary to provide Vistra with funds to satisfy its obligations, including those under the TRA, whether by dividends, distributions, loans or otherwise, will depend on, among other things, such subsidiary's results of operations, financial condition, cash flows, cash requirements, contractual prohibitions and other restrictions, applicable law and other factors. The deterioration of income from, or other available assets of, any such subsidiary for any reason could limit or impair its ability to pay dividends or make other distributions to Vistra. Evolving expectations from stakeholders, including investors, on ESG issues, including climate change and sustainability matters, and erosion of stakeholder trust or confidence could influence actions or decisions about our company and our industry and could adversely affect our business, operations, financial results or stock price. Companies across all industries are facing evolving expectations or increasing scrutiny from stakeholders related to their approach to ESG matters. For Vistra, climate change, safety and stakeholder relations remain primary focus areas, and changing expectations of our practices and performance across these and other ESG areas may impose additional costs or create exposure to new or additional risks. Our operations, projects and growth opportunities require us to have strong relationships with key stakeholders, including local communities and other groups directly impacted by our activities, as well as governments and government agencies, investor advocacy groups, certain institutional investors, investment funds and others which are increasingly focused on ESG practices. Certain financial institutions have announced policies to presently or in the future cease investing or to divest investments in companies that derive any or a specified portion of their income from, or have any or a specified portion of their operations in, fossil fuels. While we are strategically focused on successfully adapting to the energy transition and strongly committed to our ESG practices and performance (including transparency and accountability thereof), our plans to transition to clean power generation sources and reduce our carbon footprint may not be completed in the timeframe and we may not achieve our targets as expected, which could impact stakeholder trust and confidence. Any such erosion of stakeholder trust and confidence, evolving expectations from stakeholders on such ESG issues, and such parties' resulting actions or decisions about our company and our industry could have negative impacts on our business, operations, financial results, and stock price, including: negative stakeholder sentiment toward us and our industry, including concerns over environmental or sustainability matters and potential changes in federal and state regulatory actions related thereto; loss of business or loss of market share, including to competitors who do not have any, or comparable amounts, of operations involving fossil fuels; loss of ability to secure growth opportunities; the inability to, or increased difficulties and costs of, obtaining services, materials, or insurance from third parties; reductions in our credit ratings or increased costs of, or limited access to, capital; delays in project execution; legal action; inability or limitations on ability to receive applicable government subsidies, or competitors with smaller or no fossil operations receiving subsidies for which we are not eligible, or in larger amounts; increased regulatory oversight; loss of ability to obtain and maintain necessary approvals and permits from governments and regulatory agencies on a timely basis and on acceptable terms; impediments on our ability to acquire or renew rights-of-way or land rights on a timely basis and on acceptable terms; changing investor sentiment regarding investment in the power and utilities industry or our company; restricted access to and cost of capital; and loss of ability to hire and retain top talent. We may not pay any dividends on our common stock in the future, and we may not realize the anticipated benefits of our share repurchase program. In November 2018, we announced that the Board had adopted a dividend program which we initiated in the first quarter of 2019. Each dividend under the program will be subject to declaration by the Board and, thus, may be subject to numerous factors in existence at the time of any such declaration including, but not limited to, prevailing market conditions, our results of operations, financial condition and liquidity, contractual prohibitions and other restrictions with respect to the payment of dividends. There is no assurance that the Board will declare, or that we will pay, any dividends on our common stock in the future. In October 2021, our Board approved a share repurchase program under which up to $2.0 billion of our outstanding common stock may be repurchased. In August 2022, our Board authorized an incremental $1.25 billion for repurchases to bring the total authorized under the share repurchase program to $3.25 billion. Under this share repurchase program or any other future share repurchase programs, we may make share repurchases through a variety of methods, including open share market purchases or privately negotiated transactions. The timing and amount of repurchases, if any, will depend on factors such as the stock price, economic and market conditions, and corporate and regulatory requirements. Any failure to repurchase shares after we have announced our intention to do so may negatively impact our reputation, investor confidence and the price of our common stock. Holders of our preferred stock may have interests and rights that are different from our common stockholders. We are permitted under our certificate of incorporation to issue up to 100,000,000 shares of preferred stock. We can issue shares of our preferred stock in one or more series and can set the terms of the preferred stock without seeking any further approval from our common stockholders.

Any preferred stock that we issue may rank ahead of our common stock in terms of dividend priority or liquidation premiums and may have greater voting rights than our common stock, which could dilute the value of our common stock to current stockholders and could adversely affect the market price of our common stock. As of December 31, 2022, 1,000,000 shares of Series A Preferred Stock and 1,000,000 shares of Series B Preferred Stock were issued and outstanding. The Preferred Stock represents a perpetual equity interest in the Company and, unlike our indebtedness, will not give rise to a claim for payment of a principal amount at a particular date; provided , the Company may redeem the Preferred Stock at the specified times (or upon certain specified events) at the applicable redemption price set forth in the certificate of designation of each of the Series A Preferred Stock and Series B Preferred Stock, respectively (Certificates of Designation). The Preferred Stock is not convertible into or exchangeable for any other securities of the Company. Upon the liquidation, dissolution or winding up of the Company, whether voluntary or involuntary, after payment or provision for payment of the debts and other liabilities of the Company, the holders of Preferred Stock will be entitled to receive, pro rata and in preference to the holders of any other capital stock, an amount per share equal to $1,000 plus accrued and unpaid dividends thereon, if any. Unless we have received the affirmative vote or consent of the holders of at least two-thirds of the outstanding Series A Preferred Stock and the holders of at least two-thirds of the outstanding Series B Preferred Stock, voting as a separate class, we may not adopt any amendment to our certificate of incorporation (including the applicable Certificates of Designation) that would have a material adverse effect on the powers, preferences, duties, or special rights of such series of Preferred Stock, subject to certain exceptions. In addition, unless we have received the affirmative vote or consent of the holders of at least two-thirds of the outstanding Series A Preferred Stock and the holders of at least two-thirds of the outstanding Series B Preferred Stock, voting as a class together with the holders of any parity securities upon which like voting rights have been conferred and are exercisable, we may not: (i) create or issue any senior securities, (ii) create or issue any parity securities (including any additional Preferred Stock) if the cumulative dividends payable on the outstanding Preferred Stock (or parity securities, if applicable) are in arrears; (iii) create or issue any additional Preferred Stock or any parity securities with an aggregate liquidation preference, together with the issued and outstanding Preferred Stock and any parity securities that are then outstanding, of greater than $2.5 billion, and (iv) engage in any Transaction that results in a Covered Disposition (as such terms are defined in the Certificates of Designation). In addition, holders of the Preferred Stock are entitled to receive, when, as, and if declared by our Board, semi-annual cash dividends on the Preferred Stock, which are cumulative from the applicable initial issuance date of the Preferred Stock and payable in arrears, and unless full cumulative dividends have been or contemporaneously are being paid or declared on the Preferred Stock, we may not (i) declare or pay any dividends on any junior securities, including our common stock, or (ii) redeem or repurchase any parity securities or junior securities, subject to limited exceptions set forth in the Certificates of Designation. There is no assurance that the Board will declare, or that we will pay, any dividends on our Preferred Stock in the future. The holders of Preferred Stock (along with any parity securities then outstanding with similar rights) are entitled to elect two additional directors in the event any dividends on Preferred Stock are in arrears for three or more semi-annual dividend periods (whether or not consecutive), and such directors may have competing and different interests to those elected by our common stockholders. The dividend rate for the Series A Preferred Stock from and including the initial issuance date of October 15, 2021 until the first reset date of October 15, 2026 will be 8.0% per annum of the $1,000 liquidation preference per share of Series A Preferred Stock. The dividend rate for the Series B Preferred Stock from and including the initial issuance date of December 10, 2021 until the first reset date of December 15, 2026 will be 7.0% per annum of the $1,000 liquidation preference per share of Series B Preferred Stock. On and after the first reset date of the Series A Preferred Stock, the dividend rate on the Series A Preferred Stock for each subsequent five-year period (each, a Reset Period) will be adjusted based upon the applicable Treasury rate, plus a spread of 6.93% per annum; provided that the applicable Treasury rate for each Reset Period will not be lower than 1.07%. On and after the first reset date of the Series B Preferred Stock, the dividend rate on the Series B Preferred Stock for each Reset Period will be adjusted based upon the applicable Treasury rate, plus a spread of 5.74% per annum; provided that the applicable Treasury rate for each Reset Period will not be lower than 1.26%. In the event that the Company does not exercise its option to redeem all the shares of Preferred Stock within 120 days after the first date on which a Change of Control Trigger Event (as defined in the Certificate of Designation) occurs, the then-applicable dividend rate for the Preferred Stock will be increased by 5.00%.

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ITEM 1 BUSINESS ##TABLE_ENDDefinitions of Abbreviations ##TABLE_START Xcel Energy Inc.s Subsidiaries and Affiliates (current and former) Capital Services Capital Services, LLC Eloigne Eloigne Company e prime e prime inc. NSP-Minnesota Northern States Power Company, a Minnesota corporation NSP System The electric production and transmission system of NSP-Minnesota and NSP-Wisconsin operated on an integrated basis and managed by NSP-Minnesota NSP-Wisconsin Northern States Power Company, a Wisconsin corporation Operating companies NSP-Minnesota, NSP-Wisconsin, PSCo and SPS PSCo Public Service Company of Colorado SPS Southwestern Public Service Co. Utility subsidiaries NSP-Minnesota, NSP-Wisconsin, PSCo and SPS WGI WestGas InterState, Inc. WYCO WYCO Development, LLC Xcel Energy Xcel Energy Inc. and its subsidiaries ##TABLE_END##TABLE_START Federal and State Regulatory Agencies CPUC Colorado Public Utilities Commission DOC Minnesota Department of Commerce DOE United States Department of Energy DOT United States Department of Transportation EPA United States Environmental Protection Agency FERC Federal Energy Regulatory Commission IRS Internal Revenue Service MPCA Minnesota Pollution Control Agency MPUC Minnesota Public Utilities Commission NDPSC North Dakota Public Service Commission NERC North American Electric Reliability Corporation NMPRC New Mexico Public Regulation Commission NRC Nuclear Regulatory Commission PHMSA Pipeline and Hazardous Materials Safety Administration PSCW Public Service Commission of Wisconsin PUCT Public Utility Commission of Texas SDPUC South Dakota Public Utility Commission SEC Securities and Exchange Commission TCEQ Texas Commission on Environmental Quality ##TABLE_END##TABLE_START Electric, Purchased Gas and Resource Adjustment Clauses CIP Conservation improvement program DSM Demand side management ECA Retail electric commodity adjustment FCA Fuel clause adjustment GCA Gas cost adjustment GUIC Gas utility infrastructure cost rider RES Renewable energy standard ##TABLE_END##TABLE_START Other AFUDC Allowance for funds used during construction AMT Alternative minimum tax ALJ Administrative Law Judge ARO Asset retirement obligation ASC Financial Accounting Standards Board Accounting Standards Codification ATM At-the-market BART Best available retrofit technology CI Commercial and Industrial CapX2020 Alliance of electric cooperatives, municipals and investor-owned utilities in the upper Midwest involved in a joint transmission line planning and construction effort CCR Coal combustion residuals ##TABLE_END##TABLE_START CCR Rule Final rule (40 CFR 257.50 - 257.107) published by the EPA regulating the management, storage and disposal of CCRs as a nonhazardous waste CDD Cooling degree-days CEO Chief executive officer CFO Chief financial officer CIG Colorado Interstate Gas Company, LLC CON Certificate of Need CSPV Crystalline Silicon Photovoltaic CWIP Construction work in progress D.C. Circuit United States Court of Appeals for the District of Columbia Circuit DECON Decommissioning method where radioactive contamination is removed and safely disposed of at a requisite facility or decontaminated to a permitted level DRIP Dividend Reinvestment Program EEI Edison Electric Institute EIP Energy Impact Partners EMANI European Mutual Association for Nuclear Insurance EPS Earnings per share ETR Effective tax rate FTR Financial transmission right GAAP Generally accepted accounting principles GE General Electric GHG Greenhouse gas HDD Heating degree-days INPO Institute of Nuclear Power Operations IPP Independent power producing entity IRA Inflation Reduction Act ISO Independent System Operator ITC Investment Tax Credit LPL Lubbock Power Light MEC Mankato Energy Center MGP Manufactured gas plant MISO Midcontinent Independent System Operator, Inc. Native load Demand of retail and wholesale customers that a utility has an obligation to serve under statute or contract NAV Net asset value NEIL Nuclear Electric Insurance Ltd. NOL Net operating loss NOPR Notice of proposed rulemaking NOx Nitrogen Oxides OM Operating and maintenance OATT Open Access Transmission Tariff PFAS Per- and PolyFluoroAlkyl Substances PI Prairie Island nuclear generating plant Post-65 Post-Medicare PPA Purchased power agreement Pre-65 Pre-Medicare PTC Production tax credit REC Renewable energy credit RFP Request for proposal ROE Return on equity ROU Right-of-use RTO Regional Transmission Organization SP Standard Poors Global Ratings SERP Supplemental executive retirement plan SO 2 Sulfur dioxide SPP Southwest Power Pool, Inc. TCA Transmission cost adjustment ##TABLE_END##TABLE_START TCJA

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2017 federal tax reform enacted as Public Law No: 115-97, commonly referred to as the Tax Cuts and Jobs Act THI Temperature-humidity index TO Transmission owner TSR Total shareholder return VaR Value at Risk VIE Variable interest entity WACC Weighted Average Cost of Capital ##TABLE_END##TABLE_START Measurements Bcf Billion cubic feet KV Kilovolts KWh Kilowatt hours MMBtu Million British thermal units MW Megawatts MWh Megawatt hours ##TABLE_END##TABLE_START Where to Find More Information ##TABLE_ENDXcel Energys website address is www.xcelenergy.com. Xcel Energy makes available through its website, free of charge, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after the reports are electronically filed with or furnished to the SEC. The SEC maintains an internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically at http://www.sec.gov. The information on Xcel Energys website is not a part of, or incorporated by reference in, this annual report on Form 10-K. Xcel Energy intends to make future announcements regarding Company developments and financial performance through its website, www.xcelenergy.com, as well as through press releases, filings with the SEC, conference calls and webcasts. ##TABLE_START Forward-Looking Statements ##TABLE_ENDExcept for the historical statements contained in this report, the matters discussed herein are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including those relating to 2023 EPS guidance, long-term EPS and dividend growth rate objectives, future sales, future expenses, future tax rates, future operating performance, estimated base capital expenditures and financing plans, projected capital additions and forecasted annual revenue requirements with respect to rider filings, expected rate increases to customers, expectations and intentions regarding regulatory proceedings, and expected impact on our results of operations, financial condition and cash flows of resettlement calculations and credit losses relating to certain energy transactions, as well as assumptions and other statements are intended to be identified in this document by the words anticipate, believe, could, estimate, expect, intend, may, objective, outlook, plan, project, possible, potential, should, will, would and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we expressly disclaim any obligation to update any forward-looking information. The following factors, in addition to those discussed elsewhere in this Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2022 (including risk factors listed from time to time by Xcel Energy Inc. in reports filed with the SEC, including Risk Factors in Item 1A of this Annual Report on Form 10-K), could cause actual results to differ materially from management expectations as suggested by such forward-looking information: operational safety, including our nuclear generation facilities and other utility operations; successful long-term operational planning; commodity risks associated with energy markets and production; rising energy prices and fuel costs; qualified employee work force and third-party contractor factors; violations of our Codes of Conduct; our ability to recover costs and our subsidiaries ability to recover costs from customers; changes in regulation; reductions in our credit ratings and the cost of maintaining certain contractual relationships; general economic conditions, including recessionary conditions, inflation rates, monetary fluctuations, supply chain constraints and their impact on capital expenditures and/or the ability of Xcel Energy Inc. and its subsidiaries to obtain financing on favorable terms; availability or cost of capital; our customers and counterparties ability to pay their debts to us; assumptions and costs relating to funding our employee benefit plans and health care benefits; our subsidiaries ability to make dividend payments; tax laws; uncertainty regarding epidemics, the duration and magnitude of business restrictions including shutdowns (domestically and globally), the potential impact on the workforce, including shortages of employees or third-party contractors due to quarantine policies, vaccination requirements or government restrictions, impacts on the transportation of goods and the generalized impact on the economy; effects of geopolitical events, including war and acts of terrorism; cyber security threats and data security breaches; seasonal weather patterns; changes in environmental laws and regulations; climate change and other weather events; natural disaster and resource depletion, including compliance with any accompanying legislative and regulatory changes; costs of potential regulatory penalties; regulatory changes and/or limitations related to the use of natural gas as an energy source; challenging labor market conditions and our ability to attract and retain a qualified workforce; and our ability to execute on our strategies or achieve expectations related to environmental, social and governance matters including as a result of evolving legal, regulatory and other standards, processes, and assumptions, the pace of scientific and technological developments, increased costs, the availability of requisite financing, and changes in carbon markets. ##TABLE_START Overview ##TABLE_ENDXcel Energy (the Company) is a major U.S. regulated electric and natural gas delivery company headquartered in Minneapolis, Minnesota (incorporated in Minnesota in 1909). The Company serves customers in eight states, including portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Xcel Energy provides a comprehensive portfolio of energy-related products and services to approximately 3.8 million electric customers and 2.1 million natural gas customers through four utility subsidiaries (i.e., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS). Along with the utility subsidiaries, the transmission-only subsidiaries, WYCO (a joint venture formed with CIG to develop and lease natural gas pipelines, storage and compression facilities) and WGI (an interstate natural gas pipeline company) comprise the regulated utility operations. The Companys nonregulated subsidiaries include Eloigne, Capital Services, Venture Holdings and Nicollet Project Holdings. ##TABLE_START Subsidiary / Affiliate Function NSP-Minnesota Electric Gas NSP-Wisconsin Electric Gas PSCo Electric Gas SPS Electric WGI Interstate gas pipeline WYCO Gas storage and transportation Other Subsidiaries See Note 1 to the consolidated financial statements for further information

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##TABLE_END##TABLE_START Utility Subsidiary Overview Electric customers 3.8 million Natural gas customers 2.1 million Total assets $61.1 billion Electric generating capacity 20,897 MW Natural gas storage capacity 53.5 Bcf Electric transmission lines (conductor miles) 110,000 miles Electric distribution lines (conductor miles) 213,000 miles Natural gas transmission lines 2,200 miles Natural gas distribution lines 37,000 miles ##TABLE_END##TABLE_START Service Territory ##TABLE_END##TABLE_START Strategy ##TABLE_ENDXcel Energys vision is to be the preferred and trusted provider of the energy our customers need. We will deliver on this vision while offering a competitive total return to shareholders. Our mission is to provide our customers with safe, clean, reliable energy services they want and value at a competitive price. We execute on our vision and mission through three strategic priorities. ##TABLE_START LEAD THE CLEAN ENERGY TRANSITION ENHANCE THE CUSTOMER EXPERIENCE KEEP BILLS LOW ##TABLE_ENDOur employees are guided by our four corporate values: Connected, Committed, Safe, and Trustworthy. Our values, culture and Code of Conduct serve as the foundation upon which Xcel Energys Board of Directors, employees, contractors and suppliers approach their work in delivering on our three strategic priorities. Our sustainability and Environmental, Social and Governance commitments are summarized as follows: (1) Spans natural gas supply, delivery and customer use. (2) Includes the Xcel Energy fleet; zero-carbon fuel is electricity or other clean energy. Deliver a Competitive Total Return to Investors Successful strategy execution, along with our disciplined approach to growth, operations and management of environmental, social and governance issues, positions us to continue delivering a competitive TSR. We have consistently achieved our financial objectives, meeting or exceeding our initial earnings guidance range for 18 consecutive years and delivering dividend growth for 19 consecutive years. Over the past five years, GAAP earnings per share have grown by 7.1% annually and our annual dividend growth was 6.3%. Xcel Energy works to maintain senior secured debt credit ratings in the A range and senior unsecured debt credit ratings in the BBB+ to A range. Current ratings are consistent with this goal. LEAD THE CLEAN ENERGY TRANSITION For nearly two decades, Xcel Energy has proactively managed the risk of climate change and worked to meet increasing demand for cleaner energy. Carbon-free Electricity by 2050 In 2018, Xcel Energy became the first U.S. utility to establish a carbon-free vision, targeting 100% carbon-free electricity by 2050 with an interim goal to reduce carbon emissions 80% by 2030 (from 2005 levels), including owned and purchased power. A lead author for the climate change scientific analysis issued by the Intergovernmental Panel on Climate Change confirmed that our vision aligns with science-based scenarios likely to limit global warming to 1.5 degrees Celsius from pre-industrial levels. Goal includes owned and purchased power. The pace of achieving a carbon-free vision is governed by reliability and customer affordability. Our approved resource plans outline a clear, transparent path for reducing carbon emissions 80% using current technologies, while maintaining customer bill increases at or below the rate of inflation. Moving from 80% carbon reduction to 100% carbon-free electricity will require new dispatchable technologies that are economically viable, as well as supportive public policy. See Item 1A for risks and uncertainties related to strategic and sustainability goals and objectives. Through 2022, we reduced carbon emissions from generation serving customers by an estimated 53% (from 2005 levels) and remain on track to achieve 80% carbon reduction by 2030. Xcel Energy will be coal-free by year-end 2030, pending the approval of the proposed acceleration of the Tolk coal plant retirement to 2028. As we transition to clean energy, service reliability is a priority. Xcel Energy was ranked in the top quartile for customer reliability as determined in the 2022 Institute of Electrical and Electronics Engineers Annual Benchmarking Study. Xcel Energys wind capacity is now over 11,000 MW, including nearly 4,500 MW of owned wind. Our fleet continues to demonstrate high wind availability with 2022 performance at approximately 97%, while saving customers over $3 billion in fuel related costs and PTCs since 2017.In 2022, Minnesota and Colorado commissions approved resource plans that will add nearly 10,000 MW of utility-scale renewable energy to our systems. Beyond carbon emissions, we have significantly reduced other emissions and environmental impacts. Notable environmental improvements include: *Reductions in water consumption are from owned and purchased electricity that serves our customers. All other reductions are from owned generating plants. **Coal ash and water consumption data are as of 2021. As we prepare for early coal plant retirements, employees are provided advanced notice and offered retraining and relocation opportunities. To date, we have been successful in avoiding lay offs associated with our early coal plant retirements. We also help foster economic development opportunities to offset community economic impacts associated with coal plant closures. Xcel Energy has a long track record of working with our communities on energy, climate and environmental initiatives that impact them and has publicly committed to furthering environmental justice. 7 Significant transmission expansion will also be required to enable the clean energy transition, and Xcel Energy is already investing towards its goals. For example, our $2 billion Pathway project in Colorado will provide over 560 miles of transmission lines and enable nearly 5,500 MW of new renewable energy. In addition, as part of MISOs planned transmission expansion over the next decade, Xcel Energy has been awarded $1.2 billion of projects as part of Tranche 1. Natural Gas Use in Buildings Net Zero GHG by 2050 In 2021, we committed to reduce GHG emissions 25% by 2030 (from 2020 levels) and provide net-zero natural gas service by 2050 from the supply, distribution and end-use of natural gas. Similar to our electric plan, our vision to deliver gas service with net-zero emissions by 2050 aligns with science-based scenarios likely to limit warming by 1.5 C. Our net-zero natural gas strategy includes: Working with suppliers to purchase only low emissions gas supply by 2030. Operating the cleanest possible system to achieve net-zero methane emissions on the system by 2030. Offering customer options that promote conservation, encourage electrification, where beneficial, and incorporate clean fuels such as hydrogen and renewable natural gas. Applying high quality carbon offsets through projects that remove emissions from other parts of the economy while providing additional environmental and social benefit.

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Electrification of the Transportation Sector In addition to transitioning our own generation fleet, we are helping to decarbonize other sectors, starting with transportation. We aim to enable one out of five vehicles in our service areas to be electric by 2030, representing a nearly $2 billion investment, 0.6% to 0.7% incremental annual retail sales growth and avoidance of roughly 5 million tons of CO_2 emissions annually. By 2050, our vision is to run all vehicles in our service area with carbon-free electricity or other clean energy. We have launched new products and services across our service territories. In addition, we have an approved, transportation electrification plan in Colorado and comprehensive transportation plans in Minnesota and Wisconsin that are pending commission approval. Innovation and Policy Passage of the IRA is expected to reduce the cost of renewables for our customers, improve the competitiveness of our renewable projects and improve liquidity and credit metrics. The IRA is expected to reduce the cost of future wind projects by 50-60% and solar projects by 25-40% (levelized cost of energy basis). The IRA also lowers the costs of hydrogen production that could be used for generation and the natural gas system. Finally, the IRA is likely to provide customers additional benefits from PTCs for the generation of electricity from our nuclear fleet. New and emerging technologies are foundational to fulfilling our strategic priorities. Advancement of economical, resilient and reliable zero-carbon 24/7 power technologies, as well as advanced storage and new low-carbon fuels, are needed to deliver on our clean energy goals by 2050. We actively monitor and participate in emerging and advanced energy technologies through collaborations with researchers, technology developers, venture investors and others in our industry. We have several initiatives, pilots and demonstration projects underway that are advancing and testing the real-world applications of cutting-edge technologies. Our recently announced partnership with Form Energy to develop two 10 MW, 100-hour energy storage pilot projects is an example. ENHANCE THE CUSTOMER EXPERIENCE Xcel Energy has a comprehensive suite of renewable and conservation programs that provide customers with clean energy options and help keep their bills low. We are also transforming and expanding our electric grid to accommodate load growth, renewable energy and distributed energy resources. We are in the process of installing smart meters, which will deliver numerous customer and operational benefits, providing near-real-time communication, allowing customers to know how much energy they are using and what it will cost them. Along with the smart meters, customers will have new digital tools to make it easier to access their energy information, gain useful insights to better understand and manage their energy use and make smarter energy choices that lower their bills. KEEP BILLS LOW Customer affordability is critical to successful strategy execution. From 2013 - 2022, we have kept residential electric bill growth to 1.8% per year and below the rate of inflation. Residential gas bills were near flat, growing 0.3% per year from 2013 - 2021. Global pressures on natural gas prices increased customer natural gas bills in 2022. We pass the cost of natural gas directly to customers (without markup) through fuel clauses in most of our states, and higher gas prices affected the affordability of the service we provide. We have taken several steps to address this concern: Low-income customers are eligible to receive assistance with their bills. In 2022, we set a company record for energy assistance outreach as 193,000 customers were connected to programs that provided $216 million in funding. Xcel Energy has invested more than $2 billion over the past decade in a comprehensive suite of electric and natural gas conservation programs. We also kept OM expenses flat from 2014 through 2021. While OM increased in 2022 due to global inflation pressures and other drivers, our goal is to reduce 2023 OM expenses 2% from 2022 levels and keep them relatively flat thereafter. We continue to invest to reduce operating costs through ongoing process and technology improvements, including the use of drone technologies, automated work processes, artificial intelligence and continuous improvement methodologies. In addition, we are augmenting our One Xcel Energy Way program in 2023, which we expect to drive increased productivity and efficiency across all levels of the Company. As previously discussed, our geographic advantages in wind and solar also enable customer savings, which we call our Steel for Fuel strategy. High capacity factors, coupled with renewable tax credits and avoided fuel costs, enable Xcel Energy to add renewable energy while saving customers money. REACHING OUR GOALS RESPONSIBLY We instituted oversight of environmental performance by the Board of Directors beginning in 2000 and was among the first U.S. energy providers to tie carbon reduction to executive compensation over fifteen years ago. Xcel Energy has provided a voluntary, third-party verified annual GHG disclosure since 2005, longer than any other U.S. utility. We are a founding member of The Climate Registry and a supporter of the Task Force on Climate-Related Financial Disclosures. Our disclosures also align with the Global Reporting Initiative, Sustainability Accounting Standards Board and United Nations Sustainable Development Goals frameworks. STRENGTHEN OUR COMMUNITIES We provide a fundamental service, powering communities with safe, reliable, affordable and increasingly clean energy. For our local communities, we initiated 40 economic development projects in 2022, which are projected to create over $1.8 billion in capital investments and 2,900 jobs. Additionally, nearly 60% of our supply chain spend was local and we spent approximately $550 million with diverse suppliers. Our employees served on more than 520 nonprofit organization or local community boards in 2022. The Xcel Energy Foundation contributed $4.4 million to 426 nonprofit organizations that support its three charitable giving focus areas: STEM Career Pathways, Environmental Sustainability, and Community Vitality. The Foundation, Company, employees and retirees also contributed more than $5 million to local communities through Xcel Energys annual United Way Giving Campaign and nearly 3,000 volunteers participated in Xcel Energys annual Day of Service, supporting more than 100 nonprofit projects. VALUE PEOPLE AND OPERATE WITH INTEGRITY Champion Safety Continuously elevating the quality and safety of the workplace is a top priority. We are considered a benchmark company for our Safety Always approach, focused on eliminating life-altering injuries through a trusted, transparent culture and the use of critical controls. All employees have stop work authority and are expected to keep each other, our customers and the public safe. Employees are encouraged to speak up, share experiences and learn from events to help protect themselves, their coworkers and the public. The Board of Directors has oversight for employee and public safety through the Operations, Nuclear, Environmental and Safety committee, both of which are also tied to annual incentive compensation. Cultivate a Diverse, Best-in-Class Workforce We aim to create an inclusive culture where employees are treated equitably, and diversity is not only accepted but celebrated. This starts with our Board of Directors. The Board of Directors oversees our workforce strategy, including diversity and inclusion initiatives. In 2021, Xcel Energy added an incentive-based metric focused on diverse interview panels, executive sponsorship and employee feedback on inclusion in the workplace. A total of 70% of annual incentive pay was tied to safety, system reliability and diversity, equity and inclusion metrics. Management continuously evaluates benefits to maintain a market-competitive, performance-based, shareholder-aligned total rewards package that supports our ability to attract, engage and retain a talented and diverse workforce, while reinforcing and rewarding strong performance. We partner with educational and community organizations to attract and hire diverse employees who reflect the communities we serve and live our values. Xcel Energy had 11,982 full-time employees and workforce demographics as of December 2022 were as follows: ##TABLE_START Female Ethnically Diverse Board of Directors 33 % 17 % CEO direct reports 33 22 Management 25 12 Employees 24 18 New hires 35 24 Interns (hired throughout 2022) 32 25 ##TABLE_ENDTo help foster a culture of inclusivity, we offer leaders and employees training on microinequities and unconscious bias. The Company hosts 12 business resource groups to support employee interests and obtain diverse perspectives when solving challenges and achieving goals. Xcel Energy also respects employees freedom of association and their right to collectively organize. As of Dec. 31, 2022, approximately 42% of our employees (5,087) were covered by collective bargaining agreements. Employee turnover for 2022 and future projected retirement eligibility: ##TABLE_START Employee Turnover Retirement Eligibility Bargaining 7 % Within next 5 years 24 % Non-Bargaining 15 Within next 10 years 35 Overall (a) 11 ##TABLE_END(a) 24% of turnover was due to retirements. We have publicly confirmed our commitment to the advancement and protection of human rights, consistent with U.S. human rights laws and the general principles in the International Labour Organization Conventions. Annual Code of Conduct training is required for all employees and the Board of Directors. We do not tolerate Code of Conduct violations or other unacceptable behaviors. We expect and offer employees multiple avenues to raise concerns or report wrong-doing and do not permit any retaliation. Xcel Energy received the following recognitions in 2022: ##TABLE_START Fortune Human Rights Campaign Ethisphere GI Jobs Worlds Most Admired Companies Best Places to Work for LGBTQ Equality Worlds Most Ethical Companies Military Friendly Employer ##TABLE_ENDUtility Subsidiaries ##TABLE_START NSP-Minnesota Electric customers 1.5 million NSP-Minnesota conducts business in Minnesota, North Dakota and South Dakota and has electric operations in all three states including the generation, purchase, transmission, distribution and sale of electricity. NSP-Minnesota and NSP-Wisconsin electric operations are managed on the NSP System. NSP-Minnesota also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas in Minnesota and North Dakota. Natural gas customers 0.5 million Total assets $23.7 billion Rate Base (estimated) $15.1 billion ROE (net income / average stockholder's equity) 8.76% Electric generating capacity 8,949 MW Gas storage capacity 17.1 Bcf Electric transmission lines (conductor miles) 33,000 miles Electric distribution lines (conductor miles) 82,000 miles Natural gas transmission lines 78 miles Natural gas distribution lines 11,000 miles ##TABLE_END##TABLE_START NSP-Wisconsin Electric customers 0.3 million NSP-Wisconsin conducts business in Wisconsin and Michigan and generates, transmits, distributes and sells electricity. NSP-Minnesota and NSP-Wisconsin electric operations are managed on the NSP System. NSP-Wisconsin also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas. Natural gas customers 0.1 million Total assets $3.4 billion Rate Base (estimated) $2.1 billion ROE (net income / average stockholder's equity) 10.57% Electric generating capacity 548 MW Gas storage capacity 4.3 Bcf Electric transmission lines (conductor miles) 12,000 miles Electric distribution lines (conductor miles) 28,000 miles Natural gas transmission lines 3 miles Natural gas distribution lines 3,000 miles ##TABLE_END##TABLE_START PSCo Electric customers 1.6 million PSCo conducts business in Colorado and generates, purchases, transmits, distributes and sells electricity. PSCo also purchases, transports, distributes and sells natural gas to retail customers and transports customer-owned natural gas. Natural gas customers 1.5 million Total assets $23.6 billion Rate Base (estimated) $14.9 billion ROE (net income / average stockholder's equity) 8.23% Electric generating capacity 6,151 MW Gas storage capacity 32.1 Bcf Electric transmission lines (conductor miles) 25,000 miles Electric distribution lines (conductor miles) 79,000 miles Natural gas transmission lines 2,000 miles Natural gas distribution lines 24,000 miles ##TABLE_END##TABLE_START SPS SPS conducts business in Texas and New Mexico and generates, purchases, transmits, distributes and sells electricity. Electric customers 0.4 million Total assets $9.7 billion Rate Base (estimated) $6.7 billion ROE (net income / average stockholder's equity) 9.36% Electric generating capacity 5,249 MW Electric transmission lines (conductor miles) 41,000 miles Electric distribution lines (conductor miles) 24,000 miles ##TABLE_END##TABLE_START Operations Overview ##TABLE_ENDUtility operations are generally conducted as either electric or gas utilities in our four utility subsidiaries. ##TABLE_START Electric Operations ##TABLE_ENDElectric operations consist of energy supply, generation, transmission and distribution activities across all four operating companies. Xcel Energy had electric sales volume of 116,885 (millions of KWh), 3.8 million customers and electric revenues of $12,123 million for 2022. ##TABLE_START Electric Operations (percentage of total) Sales Volume Number of Customers Revenues Residential 23 % 86 % 29 % CI 55 12 48 Other 22 2 23 ##TABLE_ENDRetail Sales/Revenue Statistics (a) ##TABLE_START 2022 2021 KWh sales per retail customer 24,285 23,968 Revenue per retail customer $

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2,513 $ 2,405 Residential revenue per KWh 13.41 12.94 CI revenue per KWh 9.02 8.73 Total retail revenue per KWh 10.35 10.03 ##TABLE_END(a) See Note 6 to the consolidated financial statements for further information. Owned and Purchased Energy Generation 2022 Electric Energy Sources Total electric energy generation by source for the year ended Dec. 31: Carbon-Free Xcel Energys carbon-free energy portfolio includes wind, nuclear, hydroelectric, biomass and solar power from both owned generation facilities and PPAs. Carbon-free percentages will vary year-over-year based on system additions, commodity costs, weather, system demand and transmission constraints. See Item 2 Properties for further information. Wind Owned Owned and operated wind farms with corresponding capacity: ##TABLE_START Utility Subsidiary 2022 2021 Wind Farms Capacity (MW) (a) Wind Farms Capacity (MW) (b) NSP System 16 2,352 14 2,031 PSCo 2 1,059 2 1,059 SPS 2 984 2 984 Total 20 4,395 18 4,074 ##TABLE_END(a) Summer 2022 net dependable capacity. (b) Summer 2021 net dependable capacity. PPAs Number of PPAs with capacity range: ##TABLE_START Utility Subsidiary 2022 2021 PPAs Range (MW) PPAs Range (MW) NSP System 129 1 206 128 1 206 PSCo 17 23 301 17 23 301 SPS 17 1 250 17 1 250 ##TABLE_ENDCapacity Wind capacity (MW) for owned wind farms and PPAs: ##TABLE_START Utility Subsidiary 2022 2021 NSP System 4,515 3,997 PSCo 4,082 4,085 SPS 2,548 2,548 ##TABLE_ENDAverage Cost (Owned) Average cost per MWh of wind energy from owned generation: ##TABLE_START Utility Subsidiary 2022 2021 NSP System $ 18 $ 25 PSCo 11 17 SPS 13 17 ##TABLE_ENDAverage Cost (PPAs) Average cost per MWh of wind energy under existing PPAs: ##TABLE_START Utility Subsidiary 2022 2021 NSP System $ 37 $ 37 PSCo 38 35 SPS 27 27 ##TABLE_ENDWind Development Xcel Energy placed into service, repowered, or contracted for the following during 2022: ##TABLE_START Project Utility Subsidiary Capacity (MW) Dakota Range NSP-Minnesota 298 (a)(b) Nobles Repower NSP-Minnesota 200 (a)(b) Rock Aetna NSP-Minnesota 20 (a)(b) Various PPAs Various 220 (c) ##TABLE_END(a) Summer 2022 net dependable capacity. (b) Values disclosed are the maximum generation levels. Capacity is attainable only when wind conditions are sufficiently available. (c) Based on contracted capacity. Xcel Energy currently has approximately 550 MW of owned wind under development or being repowered. ##TABLE_START Project Utility Subsidiary Capacity (MW) Estimated Completion Northern Wind NSP-Minnesota 100 2023 (a) Grand Meadow Repower NSP-Minnesota 100 2023 Border Winds Repower NSP-Minnesota 150 2025 Pleasant Valley Repower NSP-Minnesota 200 2025 ##TABLE_END(a) Placed in service in January 2023. Solar PPAs Solar PPAs capacity by type: ##TABLE_START Type Utility Subsidiary Capacity (MW) Distributed Generation NSP System 1,074 Utility-Scale NSP System 269 Distributed Generation PSCo 848 Utility-Scale PSCo 732 Distributed Generation SPS 20 Utility-Scale SPS 192 Total 3,135 ##TABLE_ENDAverage Cost (PPAs) Average cost per MWh of solar energy under existing PPAs: ##TABLE_START Utility Subsidiary 2022 2021 NSP System $ 79 $ 90 PSCo 69 67 SPS 62 61 ##TABLE_ENDSolar Development In September 2022, the MPUC approved NSP-Minnesota's proposal to add 460 MW of solar facilities at the Sherco site. The project is expected to cost approximately $690 million (two phases to be completed in 2024 and 2025). As a result of the IRA, the levelized cost of the project is expected to be approximately 30% lower than previously estimated. PSCo placed approximately 200 MW of PPAs into service during 2022 and expects to place approximately 800 MW (including storage) of PPAs into service during 2023. Nuclear Xcel Energy has two nuclear plants with approximately 1,700 MW of total 2022 net summer dependable capacity that serve the NSP System. Our nuclear fleet has become one of the best performing and dependable in the nation, as rated by both the NRC and INPO. Xcel Energy secures contracts for uranium concentrates, uranium conversion, uranium enrichment and fuel fabrication to operate its nuclear plants. We use varying contract lengths as well as multiple producers for uranium concentrates, conversion services and enrichment services to minimize potential impacts caused by supply interruptions due to geographical and world political issues. Nuclear Fuel Cost Delivered cost per MMBtu of nuclear fuel consumed for owned electric generation and the percentage of total fuel requirements (nuclear, natural gas and coal): ##TABLE_START Utility Subsidiary Nuclear NSP System Cost Percent 2022 $ 0.76 51 % 2021 0.77 50 ##TABLE_ENDOther Xcel Energys other carbon-free energy portfolio includes hydro from owned generating facilities. See Item 2 Properties for further information. Fossil Fuel Xcel Energys fossil fuel energy portfolio includes coal and natural gas power from both owned generating facilities and PPAs. Coal Xcel Energy owns and operates coal units with approximately 6,200 MW of total 2022 net summer dependable capacity, which provided 23% of Xcel Energys energy mix in 2022. Xcel Energy has plans to retire all of its existing coal generation by the end of 2030. Approved early coal plant retirements: ##TABLE_START Year Utility Subsidiary Plant Unit Capacity (MW) 2023 NSP-Minnesota Sherco 2 682 2024 SPS Harrington (a) 1,018 2025 PSCo Comanche 2 335 2025 PSCo Craig 1 42 (b) 2025 PSCo Pawnee (c) 505 2026 NSP-Minnesota Sherco 1 680 2027 PSCo Hayden 2 98 (b) 2028 PSCo Hayden 1 135 (b) 2028 PSCo Craig 2 40 (b) 2028 NSP-Minnesota A.S. King 511 2030 NSP-Minnesota Sherco 3 517 (b) 2030 PSCo Comanche 3 500 (b) 2034 SPS Tolk 1 (d) 532 2034 SPS Tolk 2 (d) 535 ##TABLE_END(a) Reflects expected conversion from coal to natural gas following the TCEQ order that Harrington cease use of coal fuel by Jan. 1, 2025. (b) Based on Xcel Energys ownership interest. (c) Reflects conversion from coal to natural gas. (d) Tolk Unit 1 and 2 are approved to be retired early in 2034. S PS proposed to retire both units in 2028 in the pending New Mexico and Texas rate cases. Coal Fuel Cost Delivered cost per MMBtu of coal consumed for owned electric generation and the percentage of fuel requirements (nuclear, natural gas and coal): ##TABLE_START Coal (a) Utility Subsidiary Cost Percent NSP System 2022 $ 2.27 37 % 2021 1.95 34 PSCo 2022 1.48 55 2021 1.43 62 SPS 2022 2.37 59 2021 2.07 66 ##TABLE_END(a) Includes refuse-derived fuel and wood for the NSP System. Natural Gas Xcel Energy has 23 natural gas plants with approximately 8,100 MW of total 2022 net summer dependable capacity, which provided 24% of Xcel Energys mix in 2022. Natural gas supplies, transportation and storage services for power plants are procured to provide an adequate supply of fuel. Remaining requirements are procured through a liquid spot market. Generally, natural gas supply contracts have variable pricing that is tied to natural gas indices. Natural gas supply and transportation agreements include obligations for the purchase and/or delivery of specified volumes or payments in lieu of delivery. Natural Gas Cost Delivered cost per MMBtu of natural gas consumed for owned electric generation and the percentage of total fuel requirements (nuclear, natural gas and coal): ##TABLE_START Natural Gas Utility Subsidiary Cost Percent NSP System 2022 $ 7.58 12 % 2021 (a) 4.98 16 PSCo 2022 7.09 45 2021 (a) 8.38 38 SPS 2022 5.87 41 2021 (a) 6.72 34 ##TABLE_END(a) Reflective of Winter Storm Uri. Capacity and Demand Uninterrupted system peak demand and occurrence date: ##TABLE_START System Peak Demand (MW) 2022 2021 NSP System 9,245 June 20 8,837 June 9 PSCo 6,821 Sept. 6 6,958 July 28 SPS 4,280 July 19 4,054 Aug. 9 ##TABLE_ENDTransmission Transmission lines deliver electricity at high voltages and over long distances from power sources to transmission substations closer to customers. A strong transmission system ensures continued reliable and affordable service, ability to meet state and regional energy policy goals, and support for a diverse generation mix, including renewable energy. Xcel Energy owns approximately 110,000 conductor miles of transmission lines, serving 22,000 MW of customer load, across its service territory. Between 2023 and 2028, Xcel Energy plans to build approximately 1,700 additional conductor miles of transmission lines, primarily as part of the MISO Tranche 1 and Colorado Power Pathway projects. See Item 2 - Properties for further information. Distribution Distribution lines allow electricity to travel at lower voltages from substations directly to customers. Xcel Energy has a vast distribution network, owning and operating approximately 210,000 conductor miles of distribution lines across our eight-state service territory. To continue providing reliable, affordable electric service and enable more flexibility for customers, we are working to digitize the distribution grid, while at the same time keeping it secure. Xcel Energy plans to invest approximately $1.7 billion implementing new network infrastructure, smart meters, advanced software, equipment sensors and related data analytics capabilities. As of Dec. 31, 2022, Xcel Energy had spent approximately $765 million on these investments. Investments of this nature will further improve reliability and reduce outage restoration times for our customers, while at the same time enabling new options and opportunities for increased efficiency savings. The new capabilities will also enable integration of battery storage and other distributed energy resources into the grid, including electric vehicles. See Item 2 - Properties for further information. ##TABLE_START Natural Gas Operations ##TABLE_ENDNatural gas operations consist of purchase, transportation and distribution of natural gas to end-use residential, CI and transport customers in NSP-Minnesota, NSP-Wisconsin and PSCo. Xcel Energy had natural gas deliveries of 400,741 (thousands of MMBtu), 2.1 million customers and natural gas revenues of $3,080 million for 2022 . ##TABLE_START Natural Gas (percentage of total) Deliveries Number of Customers Revenues Residential 38 % 92 % 59 % CI 24 8 32

Transportation and other 38 1 9 ##TABLE_ENDSales/Revenue Statistics (a) ##TABLE_START 2022 2021 MMBtu sales per retail customer 116 114 Revenue per retail customer $ 1,318 $ 917 Residential revenue per MMBtu 11.97 8.61 CI revenue per MMBtu 10.45 7.20 Transportation and other revenue per MMBtu 1.16 1.20 ##TABLE_END(a) See Note 6 to the consolidated financial statements for further information. Capability and Demand Natural gas supply requirements are categorized as firm or interruptible (customers with an alternate energy supply). Maximum daily output (firm and interruptible) and occurrence date: ##TABLE_START 2022 2021 Utility Subsidiary MMBtu Date MMBtu Date (a) NSP-Minnesota 867,385 Feb. 12 899,133 Feb. 11 NSP-Wisconsin 187,961 Jan. 6 167,656 Feb. 11 PSCo 2,243,552 Dec. 22 2,316,283 Feb. 14 ##TABLE_END(a) Reflective of Winter Storm Uri. Natural Gas Supply and Cost Xcel Energy seeks natural gas supply, transportation and storage alternatives to yield a diversified portfolio, which increases flexibility, decreases interruption, financial risks and customer rates. In addition, the utility subsidiaries conduct natural gas price hedging activities approved by their states commissions. Average delivered cost per MMBtu of natural gas for regulated retail distribution: ##TABLE_START Utility Subsidiary 2022 2021 (a) NSP-Minnesota $ 7.00 $ 7.48 NSP-Wisconsin 6.68 7.11 PSCo 6.33 6.06 ##TABLE_END(a) Reflective of Winter Storm Uri. NSP-Minnesota, NSP-Wisconsin and PSCo have natural gas supply transportation and storage agreements that include obligations for purchase and/or delivery of specified volumes or to make payments in lieu of delivery. ##TABLE_START General ##TABLE_ENDGeneral Economic Conditions Economic conditions may have a material impact on Xcel Energys operating results. Management cannot predict the impact of fluctuating energy or commodity prices, pandemics, terrorist activity, war or the threat of war. We could experience a material impact to our results of operations, future growth or ability to raise capital resulting from a sustained general slowdown in economic growth or a significant increase in interest rates or inflation. Seasonality Demand for electric power and natural gas is affected by seasonal differences in the weather. In general, peak sales of electricity occur in the summer months and peak sales of natural gas occur in the winter months. As a result, the overall operating results may fluctuate substantially on a seasonal basis. Additionally, Xcel Energys operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. Competition Xcel Energy is subject to public policies that promote competition and development of energy markets. Xcel Energys industrial and large commercial customers have the ability to generate their own electricity. In addition, customers may have the option of substituting other fuels or relocating their facilities to a lower cost region. Customers have the opportunity to supply their own power with distributed generation including solar generation and in most jurisdictions can currently avoid paying for most of the fixed production, transmission and distribution costs incurred to serve them. Several states have incentives for the development of rooftop solar, community solar gardens and other distributed energy resources. Distributed generating resources are potential competitors to Xcel Energys electric service business with these incentives and federal tax subsidies. The FERC has continued to promote competitive wholesale markets through open access transmission and other means. Xcel Energys wholesale customers can purchase their output from generation resources of competing suppliers or non-contracted quantities and use the transmission systems of the utility subsidiaries on a comparable basis to serve their native load. FERC Order No. 1000 established competition for ownership of certain new electric transmission facilities under Federal regulations. Some states have state laws that allow the incumbent a Right of First Refusal to own these transmission facilities. FERC Order 2222 requires that RTO and ISO markets allow participation of aggregations of distributed energy resources. This order is expected to incentivize distributed energy resource adoption, however implementation is expected to vary by RTO/ISO and the near, medium, and long-term impacts of Order 2222 remain unclear. Xcel Energy Inc.s utility subsidiaries have franchise agreements with cities subject to periodic renewal; however, a city could seek alternative means to access electric power or gas, such as municipalization. No municipalization activities are occurring presently. While each utility subsidiary faces these challenges, Xcel Energy believes their rates and services are competitive with alternatives currently available. ##TABLE_START Governmental Regulations ##TABLE_ENDPublic Utility Regulation See Item 7 for discussion of public utility regulation. Environmental Regulation Our facilities are regulated by federal and state agencies that have jurisdiction over air emissions, water quality, wastewater discharges, solid and hazardous wastes or substances. Certain Xcel Energy activities require registrations, permits, licenses, inspections and approvals from these agencies. Xcel Energy has received necessary authorizations for the construction and continued operation of its generation, transmission and distribution systems. Our facilities strive to operate in compliance with applicable environmental standards and related monitoring and reporting requirements. However, it is not possible to determine what additional facilities or modifications to existing or planned facilities will be required as a result of changes to regulations, interpretations or enforcement policies or what effect future laws or regulations may have. We may be required to incur expenditures in the future for remediation of historic and current operating sites and other waste treatment, storage and disposal sites. There are significant environmental regulations to encourage use of clean energy technologies and regulate emissions of GHGs. We have undertaken numerous initiatives to meet current requirements and prepare for potential future regulations, reduce GHG emissions and respond to state renewable and energy efficiency goals. Future environmental regulations may result in substantial costs. Emerging Environmental Regulation Clean Air Act In April 2022, the EPA proposed regulations under the "Good Neighbor" provisions of the Clean Air Act. The proposed rules apply to Minnesota, Texas and Wisconsin. The proposal establishes an allowance trading program for NOx, potentially impacting Xcel Energy fossil fuel generating facilities. Under the proposed rule, facilities without NOx controls will have to secure additional allowances, install NOx controls, or develop a strategy of operations that utilizes the existing allowance allocations. The EPA has indicated that it intends for the rule to be final and applicable in the first half of 2023. While the financial impacts of the proposed regulation are uncertain and dependent on market forces, Xcel Energy anticipates that costs will be approximately $60 million annually and will be recoverable through regulatory mechanisms based on prior state commission practices. In a June 2022 ruling, the United States Supreme Court held that an economy-wide approach to reducing greenhouse gas emissions from coal-fired power plants was not consistent with the Clean Air Act. Therefore, if the EPA proceeds with new rules, it cannot set a standard based on economy-wide generation shifting to other sources, such as renewable energy. It is anticipated that EPA will propose rules to limit GHG emissions from new and existing coal and natural gas-fired electric generating units in 2023. If any new rules require additional investment, Xcel Energy believes that the cost of these initiatives or replacement generation would be recoverable through rates based on prior state commission practices. Coal Ash Regulation In February 2023, the EPA entered into a Consent Decree, committing the agency to either issue new proposed rules by May 5, 2023, to regulate inactive CCR landfills under the CCR Rule for the first time, or to determine no such rules are necessary by that date. If proposed rules are issued in May, the EPA has committed to a May 2024 effective date for the new rules. Until proposed rules are issued, it is not certain what the impact will be on Xcel Energy, but we anticipate that additional inactive ash units could become regulated for the first time. It is also anticipated that the EPA may issue other CCR proposed rules in 2023 that further expand the scope of the CCR Rule. Emerging Contaminants of Concern PFAS are man-made chemicals that are widely used in consumer products and can persist and bio-accumulate in the environment. Xcel Energy does not manufacture PFAS but because PFAS are so ubiquitous in products and the environment, it may impact our operations. In September 2022, the EPA proposed to designate two types of PFAS as hazardous substances under the Comprehensive Environmental Response, Compensation, and Liability Act, specifically perfluorooctanoic acid and perfluorooctanesulfonic acid. This proposed rule could result in new obligations for investigation and cleanup wherever PFAS are found to be present. The impact the proposed regulation may have on electric and gas utilities is currently uncertain. Environmental Costs Environmental costs include amounts for nuclear plant decommissioning and payments for storage of spent nuclear fuel, disposal of hazardous materials and waste, remediation of contaminated sites, monitoring of discharges to the environment and compliance with laws and permits with respect to emissions. Costs charged to operating expenses for nuclear decommissioning, spent nuclear fuel disposal, environmental monitoring and remediation and disposal of hazardous materials and waste and depreciation of previously incurred capital expenditures for environmental improvements were approximately: $365 million in 2022. $365 million in 2021. $400 million in 2020. Average annual expense of approximately $430 million from 2023 2027 is estimated for similar costs. The precise timing and amount of environmental costs, including those for site remediation and disposal of hazardous materials, are unknown. Additionally, the extent to which environmental costs will be included in and recovered through rates may fluctuate. Capital expenditures for environmental improvements were approximately: $20 million in 2022. $60 million in 2021. $30 million in 2020. Certain previously collected nuclear storage costs for the federal nuclear waste program are reimbursed to customers by the federal government as a result of a settlement we pursued regarding the governments failure to deliver a disposal program. Installments received are reimbursed to customers as approved by the MPUC and other state regulators. Other Our operations are subject to workplace safety standards under the Federal Occupational Safety and Health Act of 1970 (OSHA) and comparable state laws that regulate the protection of worker health and safety. In addition, the Company is subject to other government regulations impacting such matters as labor, competition, data privacy, etc. Based on information to date and because our policies and business practices are designed to comply with all applicable laws, we do not believe the effects of compliance on our operations, financial condition or cash flows are material. ##TABLE_START Capital Spending and Financing ##TABLE_ENDSee Item 7 for discussion of capital expenditures and funding sources. ##TABLE_START Information about our Executive Officers (a) Name Age (b) Current and Recent Positions Time in Position Robert C. Frenzel 52 Chairman of the Board of Directors, Xcel Energy Inc. December 2021 Present President and Chief Executive Officer and Director, Xcel Energy Inc. August 2021 Present Chief Executive Officer, NSP-Minnesota, NSP-Wisconsin, PSCo, and SPS August 2021 Present President and Chief Operating Officer, Xcel Energy Inc. March 2020 August 2021 Executive Vice President, Chief Financial Officer, Xcel Energy Inc. May 2016 March 2020 Senior Vice President and Chief Financial Officer, Luminant, a subsidiary of Energy Future Holdings Corp. (c) February 2012 April 2016 Brett C. Carter 56 Executive Vice President, Group President, Utilities, and Chief Customer Officer, Xcel Energy Inc. March 2022 Present Executive Vice President and Chief Customer and Innovation Officer, Xcel Energy Inc. May 2018 March 2022 Senior Vice President and Shared Services Executive, Bank of America, an institutional investment bank and financial services company October 2015 May 2018 Patricia Correa 49 Senior Vice President, Chief Human Resources Officer, Xcel Energy Inc. February 2022 Present Senior Vice President, Human Resources, Eaton Corporation, a power management company July 2019 January 2022 Vice President, Human Resources, Eaton Corporation March 2016 July 2019 Timothy OConnor 63 Executive Vice President, Chief Operations Officer, Xcel Energy Inc. August 2021 Present Executive Vice President, Chief Generation Officer, Xcel Energy Inc. March 2020 August 2021 Senior Vice President, Chief Nuclear Officer, Xcel Energy Services Inc February 2013 March 2020 Frank Prager 60 Senior Vice President, Strategy, Security and External Affairs and Chief Sustainability Officer, Xcel Energy Inc. March 2022 Present Senior Vice President, Strategy, Planning and External Affairs, Xcel Energy Inc. March 2020 March 2022 Vice President, Policy and Federal Affairs, Xcel Energy Services Inc. January 2015 March 2020 Amanda Rome 42 Executive Vice President, Chief Legal and Compliance Officer, Xcel Energy Inc. June 2022 Present

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Executive Vice President, General Counsel, Xcel Energy Inc. June 2020 June 2022 Vice President and Deputy General Counsel, Xcel Energy Services Inc. October 2019 June 2020 Managing Attorney, Xcel Energy Services Inc. July 2018 October 2019 Rotational Position, Xcel Energy Services Inc. January 2018 July 2018 Lead Assistant General Counsel, Xcel Energy Services Inc. July 2015 January 2018 Brian J. Van Abel 41 Executive Vice President, Chief Financial Officer, Xcel Energy Inc. March 2020 Present Senior Vice President, Finance and Corporate Development, Xcel Energy Services Inc. September 2018 March 2020 Vice President, Treasurer, Xcel Energy Services Inc. July 2015 September 2018 ##TABLE_END(a) No family relationships exist between any of the executive officers or directors. (b) Ages as of Feb. 23, 2023. (c) In April 2014, Energy Future Holdings Corp., the majority of its subsidiaries, including Texas Competitive Energy Holdings the parent company of Luminant, filed a voluntary bankruptcy petition under Chapter 11 of the United States Bankruptcy Code. Texas Competitive Energy Holdings emerged from Chapter 11 in October 2016. ##TABLE_START ITEM 1A RISK FACTORS ##TABLE_ENDXcel Energy is subject to a variety of risks, many of which are beyond our control. Risks that may adversely affect the business, financial condition, results of operations or cash flows are described below. Although the risks are organized by heading, and each risk is described separately, many of the risks are interrelated. These risks should be carefully considered together with the other information set forth in this report and future reports that we file with the SEC. You should not interpret the disclosure of any risk factor to imply that the risk has not already materialized. While we believe we have identified and discussed below the key risk factors affecting our business, there may be additional risks and uncertainties that are not presently known or that are not currently believed to be significant that may adversely affect our business, financial condition, results of operations or cash flows in the future. Oversight of Risk and Related Processes The Board of Directors is responsible for the oversight of material risk and maintaining an effective risk monitoring process. Management and the Board of Directors committees have responsibility for overseeing the identification and mitigation of key risks and reporting its assessments and activities to the full Board of Directors. Xcel Energy maintains a robust compliance program and promotes a culture of compliance beginning with the tone at the top. The risk mitigation process includes adherence to our Code of Conduct and compliance policies, operation of formal risk management structures and overall business management. Xcel Energy further mitigates inherent risks through formal risk committees and corporate functions such as internal audit, and internal controls over financial reporting and legal. Management identifies and analyzes risks to determine materiality and other attributes such as timing, probability and controllability. Identification and risk analysis occurs formally through risk assessment conducted by senior management, the financial disclosure process, hazard risk procedures, internal audit and compliance with financial and operational controls. Management also identifies and analyzes risk through the business planning process, development of goals and establishment of key performance indicators, including identification of barriers to implementing Xcel Energys strategy. The business planning process also identifies likelihood and mitigating factors to prevent the assumption of inappropriate risk to meet goals. Management communicates regularly with the Board of Directors and key stakeholders regarding risk. Senior management presents and communicates a periodic risk assessment to the Board of Directors, providing information on the risks that management believes are material, including financial impact, timing, likelihood and mitigating factors. The Board of Directors regularly reviews managements key risk assessments, which includes areas of existing and future macroeconomic, financial, operational, policy, environmental, safety and security risks. The oversight, management and mitigation of risk is an integral and continuous part of the Board of Directors governance of Xcel Energy. The Board of Directors assigns oversight of critical risks to each of its four committees to confirm these risks are well understood and given appropriate focus. The Audit Committee is responsible for reviewing the adequacy of the committees risk oversight and affirming appropriate aggregate oversight occurs. Committees regularly report on their oversight activities and certain risk issues may be brought to the full Board of Directors for consideration when deemed appropriate. Emerging risks are considered and assigned as appropriate during the annual Board of Directors and committee evaluation process, resulting in updates to the committee charters and annual work plans. Additionally, the Board of Directors conducts an annual strategy session where Xcel Energys future plans and initiatives are reviewed. Risks Associated with Our Business Operational Risks Our natural gas and electric generation/transmission and distribution operations involve numerous risks that may result in accidents and other operating risks and costs. Our natural gas transmission and distribution activities include inherent hazards and operating risks, such as leaks, explosions, outages and mechanical problems. Our electric generation, transmission and distribution activities include inherent hazards and operating risks such as contact, fire and outages. These risks could result in loss of life, significant property damage, environmental pollution, impairment of our operations and substantial financial losses to employees, third-party contractors, customers or the public. We maintain insurance against most, but not all, of these risks and losses. The occurrence of these events, if not fully covered by insurance, could have a material effect on our financial condition, results of operations and cash flows as well as potential loss of reputation. Other uncertainties and risks inherent in operating and maintaining Xcel Energy's facilities include, but are not limited to: Risks associated with facility start-up operations, such as whether the facility will achieve projected operating performance on schedule and otherwise as planned. Failures in the availability, acquisition or transportation of fuel or other supplies. Impact of adverse weather conditions and natural disasters, including, tornadoes, icing events, floods and droughts. Performance below expected or contracted levels of output or efficiency. Availability of replacement equipment. Availability of adequate water resources and ability to satisfy water intake and discharge requirements. Availability or changes to wind patterns. Inability to identify, manage properly or mitigate equipment defects. Use of new or unproven technology. Risks associated with dependence on a specific type of fuel or fuel source, such as commodity price risk, availability of adequate fuel supply and transportation and lack of available alternative fuel sources. Increased competition due to, among other factors, new facilities, excess supply, shifting demand and regulatory changes. Additionally, compliance with existing and potential new regulations related to the operation and maintenance of our natural gas infrastructure could result in significant costs. The PHMSA is responsible for administering the DOTs national regulatory program to assure the safe transportation of natural gas, petroleum and other hazardous materials by pipelines. The PHMSA continues to develop regulations and other approaches to risk management to assure safety in design, construction, testing, operation, maintenance and emergency response of natural gas pipeline infrastructure. We have programs in place to comply with these regulations and systematically monitor and renew infrastructure over time, however, a significant incident or material finding of non-compliance could result in penalties and higher costs of operations. Our natural gas and electric transmission and distribution operations are dependent upon complex information technology systems and network infrastructure, the failure of which could disrupt our normal business operations, which could have a material adverse effect on our ability to process transactions and provide services. Our utility operations are subject to long-term planning and project risks. Most electric utility investments are planned to be used for decades. Transmission and generation investments typically have long lead times and are planned well in advance of in-service dates and typically subject to long-term resource plans. These plans are based on numerous assumptions such as: sales growth, customer usage, commodity prices, economic activity, costs, regulatory mechanisms, customer behavior, available technology and public policy. Xcel Energys long-term resource plan is dependent on our ability to obtain required approvals, develop necessary technical expertise, allocate and coordinate sufficient resources and adhere to budgets and timelines. In addition, the long-term nature of both our planning processes and our asset lives are subject to risk. The electric utility sector is undergoing significant change (e.g., increases in energy efficiency, wider adoption of distributed generation and shifts away from fossil fuel generation to renewable generation). Customer adoption of these technologies and increased energy efficiency could result in excess transmission and generation resources, downward pressure on sales growth, and potentially stranded costs if we are not able to fully recover costs and investments. The magnitude and timing of resource additions and changes in customer demand may not coincide with evolving customer preference for generation resources and end-uses, which introduces further uncertainty into long-term planning. Efforts to electrify the transportation and building sectors to reduce GHG emissions may result in higher electric demand and lower natural gas demand over time. Higher electric demand may require us to adopt new technologies and make significant transmission and distribution investments including advanced grid infrastructure, which increases exposure to overall grid instability and technology obsolescence. Evolving stakeholder preference for lower emissions from generation sources and end-uses, like heating, may impact our resource mix and put pressure on our ability to recover capital investments in natural gas generation and delivery. Multiple states may not agree as to the appropriate resource mix, which may lead to costs to comply with one jurisdiction that are not recoverable across all jurisdictions served by the same assets. We require inputs such as coal, natural gas, uranium and water to cool our facilities. Lack of availability of these resources could jeopardize long-term operations of our facilities or make them uneconomic to operate. Our utilities are highly dependent on suppliers to deliver components in accordance with short and long-term project schedules. Our products contain components that are globally sourced from suppliers who, in turn, source components from their suppliers. A shortage of key components in which an alternative supplier is not identified could significantly impact operations and project plans for Xcel Energy and our customers. Such impacts could include timing of projects, including potential for project cancellation. Failure to adhere to project budgets and timelines adversely impacts our results of operations, financial condition or cash flows. We are subject to commodity risks and other risks associated with energy markets and energy production. A significant increase in fuel costs could cause a decline in customer demand, adverse regulatory outcomes and an increase in bad debt expense which may have a material impact on our results of operations. Despite existing fuel cost recovery mechanisms in most of our states, higher fuel costs could significantly impact our results of operations if costs are not recovered. Delays in the timing of the collection of fuel cost recoveries could impact our cash flows and liquidity. A significant disruption in supply could cause us to seek alternative supply services at potentially higher costs. Additionally, supply shortages may not be fully resolved, which negatively impacts our ability to provide services to our customers. Failure to provide service due to disruptions may also result in fines, penalties or cost disallowances through the regulatory process. Also, significantly higher energy or fuel costs relative to sales commitments negatively impacts our cash flows and results of operations. We also engage in wholesale sales and purchases of electric capacity, energy and energy-related products as well as natural gas. In many markets, emission allowances and/or RECs are also needed to comply with various statutes and commission rulings. As a result, we are subject to market supply and commodity price risk. Commodity price changes can affect the value of our commodity trading derivatives. We mark certain derivatives to estimated fair market value on a daily basis. Settlements can vary significantly from estimated fair values recorded and significant changes from the assumptions underlying our fair value estimates could cause earnings variability. The management of risks associated with hedging and trading is based, in part, on programs and procedures which utilize historical prices and trends. Public perception often does not distinguish between pass through commodity costs and base rates. High commodity prices that are being passed through to customer bills could impact our ability to recover costs for other improvements and operations. Due to the uncertainty involved in price movements and potential deviation from historical pricing, Xcel Energy is unable to fully assure that its risk management programs and procedures would be effective to protect against all significant adverse market deviations. In addition, the Company cannot fully assure that its controls will be effective against all potential risks. If such programs and procedures are not effective, Xcel Energys results of operations, financial condition or cash flows could be materially impacted. Failure to attract and retain a qualified workforce could have an adverse effect on operations. The competition for talent has become increasingly prevalent, and we have experienced increased employee turnover due to the condition of the labor market. In addition, specialized knowledge and skills are required for many of our positions, which may pose additional difficulty for us as we work to recruit, retain and motivate employees in this climate. Failure to hire and adequately train replacement employees, including the transfer of significant knowledge and expertise to new employees or future availability and cost of contract labor may adversely affect the ability to manage and operate our business. Inability to attract and retain these employees adversely impacts our results of operations, financial condition or cash flows. Our operations use third-party contractors in addition to employees to perform periodic and ongoing work. We rely on third-party contractors to perform operations, maintenance and construction work. Our contractual arrangements with these contractors typically include performance and safety standards, progress payments, insurance requirements and security for performance. Poor vendor performance or contractor unavailability could impact ongoing operations, restoration operations, regulatory recovery, our reputation and could introduce financial risk or risks of fines. Our employees, directors, third-party contractors, or suppliers may violate or be perceived to violate our Codes of Conduct, which could have an adverse effect on our reputation. We are exposed to risk of employee or third-party contractor fraud or misconduct. All employees and members of the Board of Directors are subject to comply with our Code of Conduct and are required to participate in annual training. Additionally, suppliers are subject to comply with our Supplier Code of Conduct. Xcel Energy does not tolerate discrimination, violations of our Code of Conduct or other unacceptable behaviors. However, it is not always possible to identify and deter misconduct by employees and other third-parties, which may result in governmental investigations, other actions or lawsuits. If such actions are taken against us we may suffer loss of reputation and such actions could have a material effect on our financial condition, results of operations and cash flows. Our subsidiary, NSP-Minnesota, is subject to the risks of nuclear generation. NSP-Minnesota has two nuclear generation plants, PI and Monticello. Risks of nuclear generation include: Hazards associated with the use of radioactive material in energy production, including management, handling, storage and disposal. Limitations on insurance available to cover losses that may arise in connection with nuclear operations, as well as obligations to contribute to an insurance pool in the event of damages at a covered U.S. reactor. Technological and financial uncertainties related to the costs of decommissioning nuclear plants may cause our funding obligations to change. The NRC has authority to impose licensing and safety-related requirements for the operation of nuclear generation facilities, including the ability to impose fines and/or shut down a unit until compliance is achieved. NRC safety requirements could necessitate substantial capital expenditures or an increase in operating expenses. In addition, the INPO reviews NSP-Minnesotas nuclear operations. Compliance with the INPOs recommendations could result in substantial capital expenditures or a substantial increase in operating expenses. If a nuclear incident did occur, it could have a material impact on our results of operations, financial condition or cash flows. Furthermore, non-compliance or the occurrence of a serious incident at other nuclear facilities could result in increased industry regulation, which may increase NSP-Minnesotas compliance costs. Financial Risks Our profitability depends on the ability of our utility subsidiaries to recover their costs and changes in regulation may impair the ability of our utility subsidiaries to recover costs from their customers. We are subject to comprehensive regulation by federal and state utility regulatory agencies, including siting and construction of facilities, customer service and the rates that we can charge customers. The profitability of our utility operations is dependent on our ability to recover the costs of providing energy and utility services and earn a return on capital investment. Our rates are generally regulated and are based on an analysis of the utilitys costs incurred in a test year. The utility subsidiaries are subject to both future and historical test years depending upon the regulatory jurisdiction. Thus, the rates a utility is allowed to charge may or may not match its costs at any given time. Rate regulation is premised on providing an opportunity to earn a reasonable rate of return on invested capital. There can also be no assurance that our regulatory commissions will judge all the costs of our utility subsidiaries to be prudent, which could result in disallowances, or that the regulatory process will always result in rates that will produce full recovery. Overall, management believes prudently incurred costs are recoverable given the existing regulatory framework. However, there may be changes in the regulatory environment that could impair the ability of our utility subsidiaries to recover costs historically collected from customers, or these subsidiaries could exceed caps on capital costs required by commissions and result in less than full recovery. Changes in the long-term cost-effectiveness or to the operating conditions of our assets may result in early retirements of utility facilities. While regulation typically provides cost recovery relief for these types of changes, there is no assurance that regulators would allow full recovery of all remaining costs. Higher than expected inflation or tariffs may increase costs of construction and operations. Also, rising fuel costs could increase the risk that our utility subsidiaries will not be able to fully recover their fuel costs from their customers. Adverse regulatory rulings (including changes in recovery mechanisms) or the imposition of additional regulations could have an adverse impact on our results of operations and materially affect our ability to meet our financial obligations, including debt payments and the payment of dividends on common stock. Any reductions in our credit ratings could increase our financing costs and the cost of maintaining certain contractual relationships. We cannot be assured that our current credit ratings will remain in effect, or that a rating will not be lowered or withdrawn by a rating agency. Significant events including disallowance of costs, use of historic test years, elimination of riders or interim rates, increasing depreciation lives, lower returns on equity, changes to equity ratios and impacts of tax policy may impact our cash flows and credit metrics, potentially resulting in a change in our credit ratings. In addition, our credit ratings may change as a result of the differing methodologies or change in the methodologies used by the various rating agencies. Any credit ratings downgrade could lead to higher borrowing costs or lower proceeds from equity issuances. It could also impact our ability to access capital markets. Also, our utility subsidiaries may enter into contracts that require posting of collateral or settlement if credit ratings fall below investment grade. We are subject to capital market and interest rate risks. Utility operations require significant capital investment. As a result, we frequently need to access capital markets. Any disruption in capital markets could have a material impact on our ability to fund our operations. Capital market disruption and financial market distress could prevent us from issuing commercial paper, issuing new securities or cause us to issue securities with unfavorable terms and conditions, such as higher interest rates or lower proceeds from equity issuances. Higher interest rates on short-term borrowings with variable interest rates could also have an adverse effect on our operating results. The performance of capital markets impacts the value of assets held in trusts to satisfy future obligations to decommission NSP-Minnesotas nuclear plants and satisfy our defined benefit pension and postretirement benefit plan obligations. These assets are subject to market fluctuations and yield uncertain returns, which may fall below expected returns. A decline in the market value of these assets may increase funding requirements. Additionally, the fair value of the debt securities held in the nuclear decommissioning and/or pension trusts may be impacted by changes in interest rates. We are subject to credit risks. Credit risk includes the risk that our customers will not pay their bills, which may lead to a reduction in our liquidity and an increase in bad debt expense. Credit risk is comprised of numerous factors including the price of products and services provided, the economy and unemployment rates. Credit risk also includes the risk that counterparties that owe us money or product will become insolvent and may breach their obligations. Should the counterparties fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected and incur losses. Xcel Energy may have direct credit exposure in our short-term wholesale and commodity trading activity to financial institutions trading for their own accounts or issuing collateral support on behalf of other counterparties. We may also have some indirect credit exposure due to participation in organized markets, (e.g., MISO, SPP, Electric Reliability Council of Texas and California Independent System Operator), in which any credit losses are socialized to all market participants. We have additional indirect credit exposure to financial institutions from letters of credit provided as security by power suppliers under various purchased power contracts. If any of the credit ratings of the letter of credit issuers were to drop below investment grade, the supplier would need to replace that security with an acceptable substitute. If the security were not replaced, the party could be in default under the contract. Increasing costs of our defined benefit retirement plans and employee benefits may adversely affect our results of operations, financial condition or cash flows. We have defined benefit pension and postretirement plans that cover most of our employees. Assumptions related to future costs, return on investments, interest rates and other actuarial assumptions have a significant impact on our funding requirements of these plans. Estimates and assumptions may change. In addition, the Pension Protection Act sets the minimum funding requirements for defined benefit pension plans. Therefore, our funding requirements and contributions may change in the future. Also, the payout of a significant percentage of pension plan liabilities in a single year, due to high numbers of retirements or employees leaving, would trigger settlement accounting and could require Xcel Energy to recognize incremental pension expense related to unrecognized plan losses in the year liabilities are paid. Changes in industry standards utilized in key assumptions (e.g., mortality tables) could have a significant impact on future obligations and benefit costs. Increasing costs associated with health care plans may adversely affect our results of operations. Increasing levels of large individual health care claims and overall health care claims could have an adverse impact on our results of operations, financial condition or cash flows. Health care legislation could also significantly impact our benefit programs and costs. We must rely on cash from our subsidiaries to make dividend payments. Investments in our subsidiaries are our primary assets. Substantially all our operations are conducted by our subsidiaries. Consequently, our operating cash flow and ability to service our debt and pay dividends depends upon the operating cash flows of our subsidiaries and their payment of dividends. Our subsidiaries are separate legal entities that have no obligation to pay any amounts due pursuant to our obligations or to make any funds available for dividends on our common stock. In addition, each subsidiarys ability to pay dividends depends on statutory and/or contractual restrictions which may include requirements to maintain minimum levels of equity ratios, working capital or assets. If the utility subsidiaries were to cease making dividend payments, our ability to pay dividends on our common stock or otherwise meet our financial obligations could be adversely affected. Our utility subsidiaries are regulated by state utility commissions, which possess broad powers to prioritize that the needs of the utility customers are met. We may be negatively impacted by the actions of state commissions that limit the payment of dividends by our utility subsidiaries. Federal tax law may significantly impact our business. Our utility subsidiaries collect estimated federal, state and local tax payments through their regulated rates. Changes to federal tax law may benefit or adversely affect our earnings and customer costs. Tax depreciable lives and the value/availability of various tax credits or the timeliness of their utilization may impact the economics or selection of resources. If tax rates are increased, there could be timing delays before regulated rates provide for recovery of such tax increases in revenues. In addition, certain IRS tax policies, such as tax normalization, may impact our ability to economically deliver certain types of resources relative to market prices. Macroeconomic Risks Economic conditions impact our business. Xcel Energys operations are affected by economic conditions, which correlates to customers/sales growth (decline). Economic conditions may be impacted by recessionary factors, rising interest rates and insufficient financial sector liquidity leading to potential increased unemployment, which may impact customers ability to pay their bills, which could lead to additional bad debt expense. Our utility subsidiaries face competitive factors, which could have an adverse impact on our financial condition , results of operations and cash flows. Further, worldwide economic activity impacts the demand for basic commodities necessary for utility infrastructure, which may inhibit our ability to acquire sufficient supplies. We operate in a capital-intensive industry and federal trade policy could significantly impact the cost of materials we use. There may be delays before these additional material costs can be recovered in rates. We face risks related to health epidemics and other outbreaks, which may have a material effect on our financial condition, results of operations and cash flows. Health epidemics continue to impact countries, communities, supply chains and markets. Uncertainty continues to exist regarding epidemics; the duration and magnitude of business restrictions including shutdowns (domestically and globally); the potential impact on the workforce including shortages of employees and third-party contractors due to quarantine policies, vaccination requirements or government restrictions; impacts on the transportation of goods, and the generalized impact on the economy. We cannot ultimately predict whether an epidemic will have a material impact on our future liquidity, financial condition or results of operations. Nor can we predict the impact on the health of our employees, our supply chain or our ability to recover higher costs associated with managing an outbreak. Operations could be impacted by war, terrorism or other events. Our generation plants, fuel storage facilities, transmission and distribution facilities and information and control systems may be targets of terrorist activities. Any disruption could impact operations or result in a decrease in revenues and additional costs to repair and insure our assets. These disruptions could have a material impact on our financial condition, results of operations or cash flows. The potential for terrorism has subjected our operations to increased risks and could have a material effect on our business. We have incurred increased costs for security and capital expenditures in response to these risks. The insurance industry has also been affected by these events and the availability of insurance may decrease. In addition, insurance may have higher deductibles, higher premiums and more restrictive policy terms. A disruption of the regional electric transmission grid, interstate natural gas pipeline infrastructure or other fuel sources, could negatively impact our business, brand and reputation. Because our facilities are part of an interconnected system, we face the risk of possible loss of business due to a disruption caused by the actions of a neighboring utility. We also face the risks of possible loss of business due to significant events such as severe storms, temperature extremes, wildfires (particularly in Colorado), widespread pandemic, generator or transmission facility outage, pipeline rupture, railroad disruption, operator error, sudden and significant increase or decrease in wind generation or a workforce disruption. In addition, major catastrophic events throughout the world may disrupt our business. While we have business continuity plans in place, our ability to recover may be prolonged due to the type and extent of the event. Xcel Energy participates in a global supply chain, which includes materials and components that are globally sourced. A prolonged disruption could result in the delay of equipment and materials that may impact our ability to connect, restore and reliably serve our customers. A major disruption could result in a significant decrease in revenues, additional costs to repair assets, and an adverse impact on the cost and availability of insurance, which could have a material impact on our results of operations, financial condition or cash flows. A cyber incident or security breach could have a material effect on our business. We operate in an industry that requires the continued operation of sophisticated information technology, control systems and network infrastructure. In addition, we use our systems and infrastructure to create, collect, use, disclose, store, dispose of and otherwise process sensitive information, including Company data, customer energy usage data, and personal information regarding customers, employees and their dependents, contractors, shareholders and other individuals. Xcel Energys generation, transmission, distribution and fuel storage facilities, information technology systems and other infrastructure or physical assets as well as information processed in our systems (e.g., information regarding our customers, employees, operations, infrastructure and assets) could be affected by cyber security incidents, including those caused by human error. The utility industry has been the target of several attacks on operational systems and has seen an increased volume and sophistication of cyber security incidents from international activist organizations, other countries and individuals. We expect to continue to experience attempts to compromise our information technology and control systems, network infrastructure and other assets. To date, no cybersecurity incident or attack has had a material impact on our business or results of operations. Cyber security incidents could harm our businesses by limiting our generating, transmitting and distributing capabilities, delaying our development and construction of new facilities or capital improvement projects to existing facilities, disrupting our customer operations or causing the release of customer information, all of which would likely receive state and federal regulatory scrutiny and could expose us to liability. Xcel Energys generation, transmission systems and natural gas pipelines are part of an interconnected system. Therefore, a disruption caused by the impact of a cyber security incident on the regional electric transmission grid, natural gas pipeline infrastructure or other fuel sources of our third-party service providers operations, could also negatively impact our business. Our supply chain for procurement of digital equipment and services may expose software or hardware to these risks and could result in a breach or significant costs of remediation. We are unable to quantify the potential impact of cyber security threats or subsequent related actions. Cyber security incidents and regulatory action could result in a material decrease in revenues and may cause significant additional costs (e.g., penalties, third-party claims, repairs, insurance or compliance) and potentially disrupt our supply and markets for natural gas, oil and other fuels. We maintain security measures to protect our information technology and control systems, network infrastructure and other assets. However, these assets and the information they process may be vulnerable to cyber security incidents, including asset failure or unauthorized access to assets or information. A failure or breach of our technology systems or those of our third-party service providers could disrupt critical business functions and may negatively impact our business, our brand, and our reputation. The cyber security threat is dynamic and evolves continually, and our efforts to prioritize network protection may not be effective given the constant changes to threat vulnerability. While the Company maintains insurance relating to cybersecurity events, such insurance is subject to a number of exclusions and may be insufficient to offset any losses, costs or damages experienced. Also, the market for cybersecurity insurance is relatively new and coverage available for cybersecurity events is evolving as the industry matures. Our operating results may fluctuate on a seasonal and quarterly basis and can be adversely affected by milder weather. Our electric and natural gas utility businesses are seasonal and weather patterns can have a material impact on our operating performance. Demand for electricity is often greater in the summer and winter months associated with cooling and heating. Because natural gas is heavily used for residential and commercial heating, the demand depends heavily upon weather patterns. A significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. Unusually mild winters and summers could have an adverse effect on our financial condition, results of operations or cash flows. Public Policy Risks Increased risks of regulatory penalties could negatively impact our business. The Energy Act increased civil penalty authority for violation of FERC statutes, rules and orders. FERC can impose penalties of up to $1.5 million per violation per day, particularly as it relates to energy trading activities for both electricity and natural gas. In addition, NERC electric reliability standards and critical infrastructure protection requirements are mandatory and subject to potential financial penalties. Also, the PHMSA, Occupational Safety and Health Administration and other federal agencies have the authority to assess penalties. In the event of serious incidents, these agencies may pursue penalties. In addition, certain states have the authority to impose substantial penalties. If a serious reliability, cyber or safety incident did occur, it could have a material effect on our results of operations, financial condition or cash flows. The continued use of natural gas for both power generation and gas distribution have increasingly become a public policy advocacy target. These efforts may result in a limitation of natural gas as an energy source for both power generation and heating, which could impact our ability to reliably and affordably serve our customers. In recent years, there have been various local and state agency proposals within and outside our service territories that would attempt to restrict the use and availability of natural gas. If such policies were to prevail, we may be forced to make new resource investment decisions which could potentially result in stranded costs if we are not able to fully recover costs and investments and impact the overall reliability of our service. Environmental Policy Risks We may be subject to legislative and regulatory responses to climate change, with which compliance could be difficult and costly. Legislative and regulatory responses related to climate change may create financial risk as our facilities may be subject to additional regulation at either the state or federal level in the future. International agreements could additionally lead to future federal or state regulations. In 2015, the United Nations Framework Convention on Climate Change reached consensus among 190 nations on an agreement (the Paris Agreement) that establishes a framework for GHG mitigation actions by all countries, with a goal of holding the increase in global average temperature to below 2 Celsius above pre-industrial levels and an aspiration to limit the increase to 1.5 Celsius. International commitments and agreements could result in future additional GHG reductions in the United States. In addition, in 2023 the EPA intends to publish draft regulations for GHG emissions from the power sector consistent with the agencys Clean Air Act authorities. Many states and localities continue to pursue their own climate policies. The steps Xcel Energy has taken to date to reduce GHG emissions, including energy efficiency measures, adding renewable generation and retiring or converting coal plants to natural gas, occurred under state-endorsed resource plans, renewable energy standards and other state policies. We may be subject to climate change lawsuits. An adverse outcome could require substantial capital expenditures and possibly require payment of substantial penalties or damages. Defense costs associated with such litigation can also be significant and could affect results of operations, financial condition or cash flows if such costs are not recovered through regulated rates. If our regulators do not allow us to recover all or a part of the cost of capital investment or the OM costs incurred to comply with the mandates, it could have a material effect on our results of operations, financial condition or cash flows. We are subject to environmental laws and regulations, with which compliance could be difficult and costly. We are subject to environmental laws and regulations that affect many aspects of our operations, including air emissions, water quality, wastewater discharges and the generation, transport and disposal of solid wastes and hazardous substances. Laws and regulations require us to obtain permits, licenses, and approvals and to comply with a variety of environmental requirements. Environmental laws and regulations can also require us to restrict or limit the output of facilities or the use of certain fuels, shift generation to lower-emitting facilities, install pollution control equipment, clean up spills and other contamination and correct environmental hazards. Failure to meet requirements of environmental mandates may result in fines or penalties. We may be required to pay all or a portion of the cost to remediate sites where our past activities, or the activities of other parties, caused environmental contamination. Changes in environmental policies and regulations or regulatory decisions may result in early retirements of our generation facilities. While regulation typically provides relief for these types of changes, there is no assurance that regulators would allow full recovery of all remaining costs. We are subject to mandates to provide customers with clean energy, renewable energy and energy conservation offerings. It could have a material effect on our results of operations, financial condition or cash flows if our regulators do not allow us to recover the cost of capital investment or OM costs incurred to comply with the requirements. In addition, existing environmental laws or regulations may be revised and new laws or regulations may be adopted. We may also incur additional unanticipated obligations or liabilities under existing environmental laws and regulations. We are subject to physical and financial risks associated with climate change and other weather, natural disaster and resource depletion impacts. Climate change can create physical and financial risk. Physical risks include changes in weather conditions and extreme weather events. Our customers energy needs vary with weather. To the extent weather conditions are affected by climate change, customers energy use could increase or decrease. Increased energy use due to weather changes may require us to invest in generating assets, transmission and infrastructure. Decreased energy use due to weather changes may result in decreased revenues. Climate change may impact the economy, which could impact our sales and revenues. The price of energy has an impact on the economic health of our communities. The cost of additional regulatory requirements, such as regulation of GHG, could impact the availability of goods and prices charged by our suppliers which would normally be borne by consumers through higher prices for energy and purchased goods. To the extent financial markets view climate change and emissions of GHGs as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less than ideal terms and conditions. We establish strategies and expectations related to climate change and other environmental matters. Our ability to achieve any such strategies or expectations is subject to numerous factors and conditions, many of which are outside of our control. Examples of such factors include, but are not limited to, evolving legal, regulatory, and other standards, processes, and assumptions, the pace of scientific and technological developments, increased costs, the availability of requisite financing, and changes in carbon markets. Failures or delays (whether actual or perceived) in achieving our strategies or expectations related to climate change and other environmental matters could adversely affect our business, operations, and reputation, and increase risk of litigation. Severe weather impacts our service territories, primarily when thunderstorms, flooding, tornadoes, wildfires and snow or ice storms or extreme temperatures (high heating/cooling days) occur. Extreme weather conditions in general require system backup and can contribute to increased system stress, including service interruptions. Extreme weather conditions creating high energy demand may raise electricity prices, increasing the cost of energy we provide to our customers. To the extent the frequency of extreme weather events increases, this could increase our cost of providing service and result in more frequent service interruptions. Periods of extreme temperatures could also impact our ability to meet demand. More frequent and severe drought conditions, extreme swings in amount and timing of precipitation, changes in vegetation, unseasonably warm temperatures, very low humidity, stronger winds and other factors have increased the duration of the wildfire season and the potential impact of an event. Also, the expansion of the wildland urban interface increases the wildfire risk to surrounding communities and Xcel Energy's electric and natural gas infrastructure. Other potential risks associated with wildfires include the inability to secure sufficient insurance coverage, or increased costs of insurance, regulatory recovery risk, and the potential for a credit downgrade and

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subsequent additional costs to access capital markets. While we carry liability insurance, given an extreme event, if Xcel Energy was found to be liable for wildfire damages, amounts that potentially exceed our coverage could negatively impact our results of operations, financial condition or cash flows. Drought or water depletion could adversely impact our ability to provide electricity to customers, cause early retirement of power plants and increase the cost for energy. Adverse events may result in increased insurance costs and/or decreased insurance availability. We may not recover all costs related to mitigating these physical and financial risks. ##TABLE_START