UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☒	ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2023

— OR —

☐	TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __ to __

Commission File Number 001-38086

Vistra Corp.

(Exact name of registrant as specified in its charter)

Delaware		**36-4833255**
(State or other jurisdiction of incorporation or organization)		(I.R.S. Employer Identification No.)
6555 Sierra Drive Irving, Texas 75039		**(214) 812-4600**
(Address of principal executive offices) (Zip Code)		(Registrant's telephone number, including area code)

	Title of Each Class	Trading Symbol(s)	Name of Each Exchange on Which Registered
Securities registered pursuant to Section 12(b) of the Act:	Common stock, par value $0.01 per share	VST	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicated by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☒	Accelerated filer	☐	Non-accelerated filer	☐	Smaller reporting company	☐	Emerging growth company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

As of June 30, 2023, the aggregate market value of the Vistra Corp. common stock held by non-affiliates of the registrant was $9,654,651,880 based on the closing sale price as reported on the New York Stock Exchange.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

Class	**Outstanding as of February 23, 2024**
Common stock, par value $0.01 per share	347,885,110

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive Proxy Statement relating to its 2024 Annual Meeting of Stockholders are incorporated by reference in Part III of this annual report on Form 10-K.

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GLOSSARY OF TERMS AND ABBREVIATIONS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Current and Former Related Entities:	
Ambit	Ambit Holdings, LLC, and/or its subsidiaries (d/b/a Ambit), depending on context
Crius	Crius Energy Trust and/or its subsidiaries, depending on context
Dynegy	Dynegy Inc., and/or its subsidiaries, depending on context
Dynegy Energy Services	Dynegy Energy Services, LLC and Dynegy Energy Services (East), LLC (each d/b/a Dynegy, Better Buy Energy, Brighten Energy, Honor Energy and True Fit Energy), indirect, wholly owned subsidiaries of Vistra, that are REPs in certain areas of MISO and PJM, respectively, and are engaged in the retail sale of electricity to residential and business customers.
Homefield Energy	Illinois Power Marketing Company (d/b/a Homefield Energy), an indirect, wholly owned subsidiary of Vistra, a REP in certain areas of MISO that is engaged in the retail sale of electricity to municipal customers
Luminant	subsidiaries of Vistra engaged in competitive market activities consisting of electricity generation and wholesale energy sales and purchases as well as commodity risk management
Merger Sub	Black Pen Inc., an indirect, wholly owned subsidiary of Vistra
Oncor	Oncor Electric Delivery Company LLC, a direct, majority-owned subsidiary of Oncor Holdings and formerly an indirect subsidiary of EFH Corp., that is engaged in regulated electricity transmission and distribution activities
Parent	Vistra Corp.
Public Power	Public Power, LLC (d/b/a Public Power), an indirect, wholly owned subsidiary of Vistra, a REP in certain areas of PJM, ISO-NE, NYISO and MISO that is engaged in the retail sale of electricity to residential and business customers
TCEH or Predecessor	Texas Competitive Electric Holdings Company LLC, a direct, wholly owned subsidiary of Energy Future Competitive Holdings Company LLC, and, prior to the Effective Date, the parent company of the TCEH Debtors whose major subsidiaries included Luminant and TXU Energy
TriEagle Energy	TriEagle Energy, LP (d/b/a TriEagle Energy, TriEagle Energy Services, Eagle Energy, Energy Rewards, Power House Energy and Viridian Energy), an indirect, wholly owned subsidiary of Vistra, a REP in certain areas of ERCOT and PJM that is engaged in the retail sale of electricity to residential and business customers
TXU Energy	TXU Energy Retail Company LLC (d/b/a TXU), an indirect, wholly owned subsidiary of Vistra that is a REP in competitive areas of ERCOT and is engaged in the retail sale of electricity to residential and business customers
U.S. Gas & Electric	U.S. Gas and Electric, LLC (d/b/a USG&E, Illinois Gas & Electric and ILG&E), an indirect, wholly owned subsidiary of Vistra, a REP in certain areas of PJM, ISO-NE, NYISO and MISO that is engaged in the retail sale of electricity to residential and business customers
Value Based Brands	Value Based Brands LLC (d/b/a 4Change Energy, Express Energy and Veteran Energy), an indirect, wholly owned subsidiary of Vistra that is a REP in competitive areas of ERCOT and is engaged in the retail sale of electricity to residential and business customers
Vistra	Vistra Corp., and/or its subsidiaries, depending on context
Vistra Intermediate	Vistra Intermediate Company LLC, a direct, wholly owned subsidiary of Vistra
Vistra Operations	Vistra Operations Company LLC, an indirect, wholly owned subsidiary of Vistra that is the issuer of certain series of notes (see Note 12 to the Financial Statements) and borrower under the Vistra Operations Credit Facilities
Vistra Zero	subsidiaries of Vistra engaged in the operation and development of renewables and energy storage assets resulting in continued modernization of our generation fleet.
Transmission System Operators:	
CAISO	The California Independent System Operator
ERCOT	Electric Reliability Council of Texas, Inc.
ISO-NE	ISO New England Inc.
MISO	Midcontinent Independent System Operator, Inc.

PJM	PJM Interconnection, LLC
Authoritative Organizations:	
CFTC	U.S. Commodity Futures Trading Commission
CPUC	California Public Utilities Commission
EPA	U.S. Environmental Protection Agency
FERC	U.S. Federal Energy Regulatory Commission
FTC	Federal Trade Commission
IEPA	Illinois Environmental Protection Agency
IPCB	Illinois Pollution Control Board
IRS	U.S. Internal Revenue Service
MSHA	U.S. Mine Safety and Health Administration
NERC	North American Electric Reliability Corporation
NRC	U.S. Nuclear Regulatory Commission
PUCT	Public Utility Commission of Texas
RCT	Railroad Commission of Texas, which among other things, has oversight of lignite mining activity in Texas, and has jurisdiction over oil and natural gas exploration and production, permitting and inspecting intrastate pipelines, and overseeing natural gas utility rates and compliance
SEC	U.S. Securities and Exchange Commission
TCEQ	Texas Commission on Environmental Quality
TRE	Texas Reliability Entity, Inc., an independent organization that develops reliability standards for the ERCOT region and monitors and enforces compliance with NERC standards and monitors compliance with ERCOT protocols
Rules and Regulations:	
CAA	Clean Air Act
Exchange Act	Securities Exchange Act of 1934, as amended
IRA	Inflation Reduction Act of 2022
Securities Act	Securities Act of 1933, as amended
General Terms:	
2022 Form 10-K	Vistra's annual report on Form 10-K for the year ended December 31, 2022, filed with the SEC on March 1, 2023
Ambit Transaction	the acquisition of Ambit by an indirect, wholly owned subsidiary of Vistra on November 1, 2019 (Ambit Acquisition Date)
ARO	asset retirement and mining reclamation obligation
CCGT	combined cycle natural gas turbine
CCR	coal combustion residuals
Chapter 11 Cases	Cases in the U.S. Bankruptcy Court for the District of Delaware (Bankruptcy Court) concerning voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code (Bankruptcy Code) filed on April 29, 2014 (Petition Date) by Energy Future Holdings Corp. (EFH Corp.) and the majority of its direct and indirect subsidiaries, including Energy Future Intermediate Holding Company LLC, Energy Future Competitive Holdings Company LLC and TCEH but excluding Oncor Electric Delivery Holdings Company LLC and its direct and indirect subsidiaries (Debtors). On October 3, 2016 (Effective Date), subsidiaries of TCEH that were Debtors in the Chapter 11 Cases (TCEH Debtors), along with certain other Debtors that became subsidiaries of Vistra on that date (Contributed EFH Debtors), completed their reorganization under the Bankruptcy Code and emerged from the Chapter 11 Cases as subsidiaries of a newly formed company, Vistra (Emergence).
CME	Chicago Mercantile Exchange
CO_2	carbon dioxide
Crius Transaction	the acquisition of equity interests of two wholly owned subsidiaries of Crius that indirectly owned the operating business of Crius by an indirect, wholly owned

CT	combustion turbine
Dynegy Merger	the merger of Dynegy with and into Vistra, with Vistra as the surviving corporation
Dynegy Merger Date	April 9, 2018, the date Vistra and Dynegy completed the transactions contemplated by the Agreement and Plan of Merger, dated as of October 29, 2019, by and between Vistra and Dynegy
EBITDA	earnings (net income) before interest expense, income taxes, depreciation and amortization
Energy Harbor	Energy Harbor Corp., and/or its subsidiaries, depending on context
ESG	environmental, social and governance
ESS	energy storage system
Fitch	Fitch Ratings Inc. (a credit rating agency)
GAAP	generally accepted accounting principles
GHG	greenhouse gas
GWh	gigawatt-hours
Green Finance Framework	Framework adopted by the Company and made available on its website pursuant to which the Company may issue financial instruments to fund new or existing projects that support renewable energy and energy efficiency, with alignment to the Company's environmental, social, and governance strategy
Heat Rate	Heat Rate is a measure of the efficiency of converting a fuel source to electricity
ICE	Intercontinental Exchange
ISO	independent system operator
ITC	investment tax credit
kW	kilowatt
LIBOR	London Interbank Offered Rate, an interest rate at which banks can borrow funds, in marketable size, from other banks in the London interbank market
load	demand for electricity
LTSA	long-term service agreements for plant maintenance
Market Heat Rate	Market Heat Rate is the implied relationship between wholesale electricity prices and natural gas prices and is calculated by dividing the wholesale market price of electricity, which is based on the price offer of the marginal supplier (generally natural gas plants), by the market price of natural gas.
MMBtu	million British thermal units
Moody's	Moody's Investors Service, Inc. (a credit rating agency)
MW	megawatts
MWh	megawatt-hours
NO_X	nitrogen oxide
NYMEX	the New York Mercantile Exchange, a commodity derivatives exchange
NYSE	New York Stock Exchange
OPEB	postretirement employee benefits other than pensions
Plan of Reorganization	Third Amended Joint Plan of Reorganization filed by the Debtors in August 2016 and confirmed by the Bankruptcy Court in August 2016 solely with respect to the TCEH Debtors and the Contributed EFH Debtors
PrefCo Preferred Stock Sale	as part of the tax-free spin-off from EFH Corp. executed pursuant to the Plan of Reorganization on the Effective Date by the TCEH Debtors and the Contributed EFH Debtors (Spin-Off), the contribution of certain of the assets of the Predecessor and its subsidiaries by a subsidiary of TEX Energy LLC to Vistra Preferred Inc. (PrefCo) in exchange for all of PrefCo's authorized preferred stock, consisting of 70,000 shares, par value $0.01 per share
PTC	production tax credit
REP	retail electric provider
RTO	regional transmission organization

Series B Preferred Stock	Vistra's 7.0% Series B Fixed-Rate Reset Cumulative Green Redeemable Perpetual Preferred Stock, $0.01 par value, with a liquidation preference of $1,000 per share
Series C Preferred Stock	Vistra's 8.875% Series C Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock, $0.01 par value, with a liquidation preference of $1,000 per share
SG&A	selling, general and administrative
SO_2	sulfur dioxide
SOFR	Secured Overnight Financing Rate, the average rate at which institutions can borrow U.S. dollars overnight while posting U.S. Treasury Bonds as collateral
ST	steam turbine
Tax Matters Agreement	Tax Matters Agreement, dated as of the Effective Date, by and among EFH Corp., Energy Future Intermediate Holding Company LLC, EFIH Finance Inc. and EFH Merger Co. LLC
TRA	Tax Receivable Agreement, containing certain rights (TRA Rights) to receive payments from Vistra related to certain tax benefits, including benefits realized as a result of certain transactions entered into at Emergence (see Note 8 to the Financial Statements)
U.S.	United States of America
Vistra Operations Commodity-Linked Credit Agreement	Credit agreement, dated as of February 4, 2022 (as amended, restated, amended and restated, supplemented, and/or otherwise modified from time to time) by and among Vistra Operations, Vistra Intermediate, the lenders party thereto, the other credit parties thereto, the administrative agent, the collateral agent, and the other parties named therein
Vistra Operations Credit Agreement	Credit agreement, dated as of October 3, 2016 (as amended, restated, amended and restated, supplemented and/or otherwise modified from time to time), by and among Vistra Operations, Vistra Intermediate, the lenders party thereto, the letter of credit issuers party thereto, the administrative agent, the collateral agent, and the other parties named therein
Vistra Operations Credit Facilities	Vistra Operations senior secured financing facilities (see Note 12 to the Financial Statements)

FORWARD-LOOKING STATEMENTS

This annual report on Form 10-K contains forward-looking statements that involve risk and uncertainties. All statements, other than statements of historical facts, that are included in this report, or made in presentations, in response to questions or otherwise, that address activities, events or developments that may occur in the future, including (without limitation) such matters as activities related to our financial or operational projections, capital allocation, capital expenditures, liquidity, dividend policy, business strategy, competitive strengths, goals, future acquisitions or dispositions, development or operation of power generation assets, market and industry developments and the growth of our businesses and operations (often, but not always, through the use of words or phrases such as "intends," "plans," "potential," "will likely," "unlikely," "believe," "expect," "anticipated," "estimate," "should," "could," "may," "projection," "forecast," "target," "goal," "objective" and "outlook"), are forward-looking statements. Although we believe that in making any such forward-looking statement our expectations are based on reasonable assumptions, any such forward-looking statement involves uncertainties and risks and is qualified in its entirety by reference to the discussion under Item 1A. *Risk Factors* and Item 7. *Management's Discussion and Analysis of Financial Condition, and Results of Operations* in this annual report on Form 10-K and the following important factors, among others, that could cause our actual results to differ materially from those projected in or implied by such forward-looking statements:

- our ability to consummate the acquisition of Energy Harbor, and if consummated, our ability to achieve synergies and forecasted operational results;
- the actions and decisions of judicial and regulatory authorities;
- prevailing applicable federal, state and local governmental policies and regulatory actions, including those of the legislatures and other government actions of states in which we operate, the U.S. Congress, the FERC, the NERC, the TRE, the public utility commissions of states and locales in which we operate, CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, the RCT, the NRC, the EPA, the environmental regulatory bodies of states in which we operate, the MSHA and the CFTC;
- expectations regarding, or impacts of, environmental matters, including costs of compliance, availability and adequacy of emission credits, and the impact of ongoing proceedings and potential regulations or changes to current regulations;
- legal and administrative proceedings and settlements;
- general industry trends;
- economic conditions, including the impact of any inflationary period, recession or economic downturn;
- investor sentiment relating to climate change and utilization of fossil fuels in connection with power generation;
- the severity, magnitude and duration of extreme weather events, drought and limitations on access to water, and other weather conditions and natural phenomena, contingencies and uncertainties relating thereto;
- acts of sabotage, geopolitical conflicts, wars, or terrorist, cybersecurity, cybercriminal, or cyber-espionage threats or activities;
- risk of contract performance claims by us or our counterparties, and risks of, or costs associated with, pursuing or defending such claims;
- our ability to collect trade receivables from counterparties in the amount or at the time expected, if at all;
- our ability to attract, retain and profitably serve customers;
- restrictions on or prohibitions of competitive retail pricing or direct-selling businesses;
- adverse publicity associated with our retail products or direct selling businesses, including our ability to address the marketplace and regulators regarding our compliance with applicable laws;
- changes in wholesale electricity prices or energy commodity prices, including the price of natural gas;
- sufficiency of, access to, and costs associated with coal, fuel oil, natural gas, and uranium inventories and transportation and storage thereof;
- changes in the ability of counterparties and suppliers to provide or deliver commodities, materials, or services as needed;
- beliefs and assumptions about the benefits of state- or federal-based subsidies to our market competition, and the corresponding impacts on us, including if such subsidies are disproportionately available to our competitors;
- the effects of, or changes to, market design and the power, ancillary services and capacity procurement processes in the markets in which we operate;
- changes in Market Heat Rates in the CAISO, ERCOT, ISO-NE, MISO, NYISO and PJM electricity markets;
- our ability to effectively hedge against unfavorable commodity prices, including the price of natural gas, market heat rates and interest rates;
- changes in market supply or demand and demographic patterns;
- our ability to mitigate forced outage risk, including managing risk associated with Capacity Performance in PJM and performance incentives in ISO-NE;
- efforts to identify opportunities to reduce congestion and improve busbar power prices;

- access to adequate transmission facilities to meet changing demands;
- changes in interest rates, commodity prices, rates of inflation or foreign exchange rates;
- changes in operating expenses, liquidity needs and capital expenditures;
- access to capital, the attractiveness of the cost and other terms of such capital and the success of financing and refinancing efforts, including availability of funds in capital markets;
- our ability to maintain prudent financial leverage and achieve our capital allocation, performance, and cost-saving initiatives and objectives;
- our ability to generate sufficient cash flow to make principal and interest payments in respect of, or refinance, our debt obligations;
- our expectation that we will continue to pay (i) a consistent aggregate cash dividend amount to common stockholders on a quarterly basis and (ii) the applicable semiannual cash dividend to the Series A Preferred Stock, Series B Preferred Stock and Series C Preferred Stock stockholders, respectively;
- our expectation that we will continue to make share repurchases under, and the possibility that we may fail to realize the anticipated benefits of, our share repurchase program, and the possibility that the program may be suspended, discontinued or not completed prior to its termination;
- our ability to implement and successfully execute upon our strategic and growth initiatives, including the completion and integration of mergers, acquisitions and/or joint venture activity, the identification and completion of sales and divestitures activity, and the completion and commercialization of our other business development and construction projects;
- competition for new energy development and other business opportunities;
- counterparties' collateral demands and other factors affecting our liquidity position and financial condition;
- changes in technology (including large-scale electricity storage) used by and services offered by us;
- changes in electricity transmission that allow additional power generation to compete with our generation assets;
- our ability to attract and retain qualified employees;
- significant changes in our relationship with our employees, including the availability of qualified personnel, and the potential adverse effects if labor disputes or grievances were to occur or changes in laws or regulations relating to independent contractor status;
- changes in assumptions used to estimate costs of providing employee benefits, including medical and dental benefits, pension and OPEB, and future funding requirements related thereto, including joint and several liability exposure under ERISA;
- hazards customary to the industry and the possibility that we may not have adequate insurance to cover losses resulting from such hazards;
- our ability to effectively and efficiently plan, prepare for and execute expected asset retirements and reclamation obligations and the impacts thereof, and
- actions by credit rating agencies.

Any forward-looking statement speaks only at the date on which it is made, and except as may be required by law, we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which it is made or to reflect the occurrence of unanticipated events or circumstances. New factors emerge from time to time, and it is not possible for us to predict them. In addition, we may be unable to assess the impact of any such event or condition or the extent to which any such event or condition, or combination of events or conditions, may cause results to differ materially from those contained in or implied by any forward-looking statement. As such, you should not unduly rely on such forward-looking statements.

INDUSTRY AND MARKET INFORMATION

Certain industry and market data and other statistical information used throughout this report are based on independent industry publications, government publications, reports by market research firms or other published independent sources, including certain data published by CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, the environmental regulatory bodies of states in which we operate and NYMEX. We did not commission any of these publications, reports or other sources. Some data is also based on good faith estimates, which are derived from our review of internal surveys, as well as the independent sources listed above. Industry publications, reports and other sources generally state that they have obtained information from sources believed to be reliable, but do not guarantee the accuracy and completeness of such information. While we believe that each of these studies, publications, reports and other sources is reliable, we have not independently investigated or verified the information contained or referred to therein and make no representation as to the accuracy or completeness of such information. Forecasts are particularly likely to be inaccurate, especially over long periods of time, and we do not know what assumptions were used in preparing such forecasts. Statements regarding industry and market data and other statistical information used throughout this report involve risks and uncertainties and are subject to change based on various factors.

PART I

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 of Terms and Abbreviations* for defined terms.

General

Vistra is an integrated retail electricity and power generation company. We combine an innovative, customer-centric approach to retail sales with safe, reliable, diverse, and efficient power generation. 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.

The Company brings its products and services to market in 20 states and the District of Columbia, including all major competitive wholesale power markets in the U.S. We serve approximately 4 million residential, commercial, and industrial retail customers with electricity and natural gas. Our generation fleet totals approximately 37,000 megawatts of generation capacity powered by a diverse portfolio, including natural gas, nuclear, coal, solar, and battery energy storage facilities. Vistra is guided by four core principles: we do business the right way, we work as a team, we compete to win, and we care about our stakeholders, including our customers, our communities where we work and live, our employees, and our investors.

Market Discussion

The operations of Vistra, as an integrated retail electricity and power generation company, are further aligned into six reportable business segments: (i) Retail, (ii) Texas, (iii) East, (iv) West, (v) Sunset and (vi) Asset Closure. Our Texas, East, West and Sunset segments include our electricity generation operations, and our Asset Closure segment is engaged in the decommissioning and reclamation of retired plants and mines.

Retail Operations

Vistra is one of the largest competitive residential retail electricity providers in the U.S. Our Retail operations are engaged in retail sales of electricity, natural gas and related services to approximately 4 million customers. Substantially all of our retail activities are conducted by TXU Energy, Ambit Energy, Dynegy Energy Services, Homefield Energy, and U.S. Gas & Electric across 19 U.S. states and the District of Columbia.

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 Dynegy Merger, as the case may be. As of December 31, 2023, we have reflected intangible assets on our balance sheet for our trade names of approximately $1.341 billion (see Note 6 to the Financial Statements).

The largest portion of our retail operations are in Texas, where we provide retail electricity to approximately 2.5 million customers. 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.

Electricity Generation Operations

Vistra is the largest competitive power generator in the U.S. as measured by MWh. At December 31, 2023, our generating capacity was powered by the following:

Primary Fuel	Technology	Net Capacity (MW)	% of Net Capacity
Natural Gas	CCGT, CT or ST	24,313	66%
Coal	ST	8,428	23%
Nuclear	Nuclear	2,400	7%
Renewable	Solar/Battery	1,358	4%
Fuel Oil	CT	203	—%
Total		36,702	100%

Our natural gas-fueled generation fleet is comprised of 23 CCGT generation facilities totaling 19,512 MW and 11 peaking generation facilities totaling 4,801 MW. We satisfy our fuel requirements at these facilities through a combination of spot market and near-term purchase contracts. Additionally, we have near-term natural gas transportation agreements and natural gas storage agreements in place to ensure reliable fuel supply.

Our coal/lignite-fueled generation fleet is comprised of seven generation facilities totaling 8,428 MW of generation capacity. Maintenance outages at these units are scheduled during the spring or fall off-peak demand periods. We meet our fuel requirements at our coal-fueled generation facilities in PJM and MISO with coal purchased from multiple suppliers under contracts of various lengths and transported to the facilities by either railcar or barges. We meet our fuel requirements in ERCOT using lignite that we mine at the Oak Grove generation facility and coal purchased and transported by railcar at the Coleto Creek and Martin Lake generation facilities.

We own and operate two nuclear generation units at the Comanche Peak plant site in ERCOT, each of which is designed for a capacity of 1,200 MW. Comanche Peak Unit 1 and Unit 2 went into commercial operation in 1990 and 1993, respectively, and are generally operated at full capacity. Refueling (nuclear fuel assembly replacement) outages for each unit are scheduled to occur every eighteen months during the spring or fall off-peak demand periods. Every three years, the refueling cycle results in the refueling of both units during the same year, which occurred in 2023. While one unit is undergoing a refueling outage, the remaining unit is intended to operate at full capacity. During a refueling outage, other maintenance, modification and testing activities are completed that cannot be accomplished when the unit is in operation. The Comanche Peak facility operated at a capacity factor of 90%, 94% and 96% in 2023, 2022 and 2021, respectively.

We have contracts in place for all of Comanche Peak's 2024 through 2027 nuclear fuel requirements. We do not anticipate any significant difficulties in acquiring uranium and contracting for associated conversion, enrichment and fabrication services in the foreseeable future, but we are closely monitoring developments that may arise out of the Russia and Ukraine conflict. See Item 7. *Management's Discussion and Analysis of Financial Condition, and Results of Operations – Significant Activities and Events, and Items Influencing Future Performance – Macroeconomic Conditions*.

Our generation operations by segment are represented in the following table:

Segment	Net Capacity (MW)	% of Net Capacity	ISO/RTO
Texas	18,151	49%	ERCOT
East	12,093	33%	PJM, ISO-NE and NYISO
West	1,880	5%	CAISO
Sunset	4,578	13%	MISO, PJM and ERCOT
Total	36,702	100%	

Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) — Separate from our operations, 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.

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 has 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 ERCOT 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 $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. In December 2023, the PUCT also approved an Emergency Pricing Program that temporarily lowers the system-wide offer cap to $2,000/MWh if prices have been at the cap for 12 hours in a rolling 24-hour period. 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 – Significant Activities and Events, and Items Influencing Future Performance*).

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. ERCOT currently procures ancillary services in the day-ahead market, but plans to implement co-optimization of energy and ancillary services in the real-time market in 2026. 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. ERCOT implemented the ERCOT Contingency Reserve Service (ECRS) in June 2023 to further address the need for operating reserves to manage load and intermittent resource output uncertainty. The Texas legislature has also directed the creation of a new ancillary service, Dispatchable Reliability Reserve Service, that is currently projected to be implemented in 2026.

PJM — PJM is an RTO that manages the flow of electricity from approximately 183,000 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. PJM's RPM auction for planning year 2025-2026 was delayed and is expected to be run in June 2024. 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 32,400 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 the 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 37,000 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 the Installed Capacity Market, 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.

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.

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 generation units with low variable operating costs. Baseload generation units can also increase output to satisfy certain incremental demand and reduce output when demand is unusually low. Intermediate/load-following generation 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, natural gas and other commodity derivative contracts to reduce exposure to changes in prices primarily to mitigate the volatility of 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 generation 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.

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, Vistra understands our obligation to balance reliability, affordability, and sustainability. To align our strategy with this obligation we have defined four strategic priorities that we aim to execute against:

- Long-term, attractive earnings profile through the integrated business model.
- Strategic energy transition that supports the reliability and affordability of electricity.
- Significant and consistent shareholder return of capital.
- Maintaining a strong balance sheet.

Long-term, attractive earnings profile through the integrated business model. Our integrated business model distinguishes us from our electricity competitors as it pairs our reliable and efficient diversified generation fleet and wholesale commodity risk management capabilities with our retail platform. Integrating retail with power generation stands as a fundamental competitive advantage that mitigates the impact of commodity price fluctuations and enhances the stability and predictability of our cash flows. Stability and predictability of cash flows are essential as we evaluate economically attractive investments.

Strategic energy transition that supports the reliability and affordability of electricity. As one of the largest electricity generators in the U.S., Vistra has led the way in decarbonization efforts and is committed to sustainability, setting aggressive targets, and transitioning our fleet to low-to-no carbon resources, all while balancing our obligations to our stakeholders. While the way we generate electricity may be changing, our essential role in providing reliable and affordable electricity is not.

Significant and consistent shareholder return of capital. We make thoughtful capital allocation decisions that balances the goal of returning significant and consistent capital to our stockholders through share repurchases and quarterly dividends with the allocation of capital to maintain current assets and explore opportunities for growth.

Maintaining a strong balance sheet. Vistra' s disciplined approach to capital management supports our commitment to maintain a strong balance sheet. A strong balance sheet ensures our access to diverse sources of liquidity and provides financial flexibility for our capital allocation decisions, including decisions to return significant and consistent capital to our stockholders.

Human Capital Resources

Vistra's approach to human capital management is guided by our core values. These values are:

- *We do business the right way.* Every decision we make and action we take will be evidence of the utmost integrity and compliance.
- *We compete to win.* We will create the leading integrated energy company with an unmatched work ethic, an analysis-driven and disciplined culture with strong leadership and decision-making throughout the organization.
- *We work as a team.* We are committed to each other, everything we do and to the success of our company.
- *We care about our key stakeholders.* We respect our fellow employees, we focus on our customers and we care about our communities where we live and do business. We will maintain productive and respectful relationship with our legislators, regulators and community leaders.

Our core values apply to all employees, suppliers and contractors and guide how we interact with our partner companies, communities, the environment and all other stakeholders. We aim to conduct all aspects of our business in accordance with these core values, which serve as the cultural foundation of the Company.

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. As of December 31, 2023, we had approximately 4,870 full-time employees, including approximately 1,200 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 2023, the generation fleet conducted more than 56,000 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. Since the implementation of our Best Defense safety program, the number of serious injuries or fatalities has decreased significantly. Although we do not focus on recordable incidents, our Total Recordable Incident rate (TRIR) for company employees was 0.54, in the top quartile as compared to the Edison Electric Institute (EEI) 2022 Total Company Injury Data. We encourage near-miss reporting and review of events to promote a learning environment. In 2023, safety learning calls were held every week where 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. Our Hopewell, Ontelaunee and Independence generation facilities completed reevaluations and were re-certified as VPP Star in 2023. 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 (BLS) 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.

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 24% of the Company's senior management positions, and ethnically diverse employees represent 27% of senior management.

During 2023, 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. We continued to utilize our fifteen 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 and analytics. The emphasis on skills-based hiring continues to evolve as we see increased mobility of employees throughout the organization as well as increased retention. Vistra is elevating its commitment to disability diversity by increasing our commitment and support level with DisabilityIn. We now have leaders on all eligible committees within the organization (executive sponsor, Chief Diversity Officer, ERG leader, accessibility). We centralized our intern program to ensure a diverse intern pool from across the country and are expanding our college partnerships to ensure geographically diverse opportunities in research, sponsorships and recruitment. Training on inclusion and acceptance is being presented to all frontline employees to ensure every employee is included in the conversation.

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 fourth 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 of Leadership provides new managers with skills to lead organizations in situational leadership, business acumen, inclusive leadership, and exposes them to best practices from across the company. We continue to evaluate and refine our programs as the development needs of our employees change. In 2023, Vistra refreshed our Front-Line Leader development program focusing on the development of supervisors and managers at our plants.

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 Vistra Learning Community is our online platform that strategically 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 2024, 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 500 employees participated in 2023. 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 14 to the Financial Statements for a discussion of litigation related to EPA reviews.

Climate Change

There is continuing emphasis domestically and internationally on 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 95 million short tons of CO_2 in the year ended 2023.

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. Since 2010, Vistra has retired more than 15,100 MW of coal and natural gas power plants resulting in a 50% reduction in carbon dioxide (CO_2) emissions, a 68% reduction in nitrogen oxide (NO_X) emissions, and an 89% reduction in sulfur dioxide (SO_2) emissions through year-end 2023, compared to a 2010 baseline. 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 battery ESS. 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 2025, and
  - up to 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 2026.
- *Battery Energy Storage Projects* — We operate battery ESS totaling 270 MW in Texas and 750 MW in California. We have announced our plans to develop up to 150 MW of battery ESS at retired or to-be-retired plant sites in Illinois with expected commercial operation dates ranging from 2024 to 2026.
- *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 Dynegy Merger.
- *Retirements of Fossil Fuel Generation* — Since 2018, lignite/coal-fueled generation facilities retired include 4,167 MW in Texas, 4,040 MW in Illinois 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.
- *Acquisition of Nuclear Generation Facilities* — In 2023, we announced the acquisition of 4,048 MW of nuclear generation facilities in PJM from Energy Harbor. We anticipate the transaction will close on March 1, 2024.

We will only invest in growth projects if we are confident in the expected returns. See Note 3 to the Financial Statements for discussion of our solar and battery ESS projects and Note 4 to the Financial Statements for discussion of our retirement of generation facilities.

Green Finance Framework

In December 2021, we announced the publication of our Green Finance Framework, which allows us to issue green financial instruments to fund new or existing projects that support renewable energy and energy efficiency with alignment to our ESG strategy. See Note 15 to the Financial Statements for more information concerning the Series B Preferred Stock issued under our Green Finance Framework.

GHG Emissions

In July 2019, the EPA finalized a rule that repealed the Clean Power Plan (CPP) 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 generation 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 opened a docket seeking input on questions related to the regulation of GHGs under Section 111(d) which closed in March 2023. In May 2023, the EPA released a new proposal regulating power plant GHG emissions, while also proposing to repeal the ACE rule. The new GHG proposal sets limits for (a) new natural gas-fired combustion turbines, (b) existing coal-, oil- and natural gas-fired steam generation units, and (c) certain existing natural gas-fired combustion turbines. The proposed standards are based on technologies such as carbon capture and sequestration/storage (CCS), low-GHG hydrogen co-firing, and natural gas co-firing. Starting in 2030, the proposal would generally require more CO_2 emissions control at fossil fuel-fired power plants that operate more frequently and for more years and would phase in increasingly stringent CO_2 requirements over time. Under the proposal, states would be required to submit plans to the EPA within 24 months of the rule's effective date that provide for the establishment, implementation, and enforcement of standards of performance for existing sources. These state plans must generally establish standards that are at least as stringent as the EPA's emission guidelines. Existing steam generation units must start complying with their standards of performance on January 1, 2030. Existing combustion turbine units must start complying with their standards of performance on January 1, 2032, or January 1, 2035, depending on their subcategory. We submitted comments to the EPA on this proposal in August 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 which may include an updated model rule.

Our generation facilities in Connecticut, Maine, Massachusetts, New Jersey, New York and Virginia emitted approximately 10 million short tons of CO_2 during 2023. The spot market price of RGGI allowances required to operate these facilities as of December 31, 2023 was approximately $15.35 per allowance. The spot market price of RGGI allowances required to operate our affected facilities during 2024 was approximately $16.21 per allowance on February 23, 2024. 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. The Virginia State Pollution Control Board withdrew the state from RGGI at the end of 2023, coinciding with the end of the program's three-year compliance period and contract with RGGI, Inc. In August 2023, opponents of the state's action filed suit seeking a stay alleging withdrawal from RGGI is impermissible without new legislation. Virginia is not participating in RGGI at this time.

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 of Pennsylvania (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. In November 2023, the Commonwealth Court found that Pennsylvania cannot join RGGI without legislative approval and enjoined the Pennsylvania Department of Environmental Protection from implementing RGGI. The state has appealed this decision to the Pennsylvania Supreme Court where it is still pending. The Pennsylvania Department of Environmental Protections has indicated it will not seek to implement RGGI until the Pennsylvania Supreme Court acts. 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' SIP and the State of Texas, Luminant, certain trade groups, and others challenged that disapproval in the U.S. Court of Appeals for the Fifth Circuit (Fifth Circuit Court). In March 2023, those same parties filed motions to stay the EPA's SIP disapproval in the Fifth Circuit Court, and the EPA moved to transfer our challenges to the D.C. Circuit Court or have those challenges dismissed.

In April 2022, prior to the EPA's disapproval of Texas' SIP, the EPA proposed a Federal Implementation Plan (FIP) to address the 2015 ozone NAAQS. 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. In March 2023, the EPA administrator signed its final FIP. The FIP applies to 22 states beginning with the 2023 ozone seasons. States where Vistra operates electric generation units that would be subject to this rule are Illinois, New Jersey, New York, Ohio, Pennsylvania, Texas, Virginia and West Virginia. Texas would be moved into the revised Group 3 trading program previously established in the Revised CSAPR Update Rule that includes emission budgets for 2023 that the EPA says are achievable through existing controls installed at power plants. Allowances will be limited under the program and will be further reduced beginning in ozone season 2026 to a level that is intended to reduce operating time of coal-fueled power plants during ozone season or force coal plants to retire, particularly those that do not have selective catalytic reduction systems such as our Martin Lake power plant.

In May 2023, the Fifth Circuit Court granted our motion to stay the EPA's disapproval of Texas' SIP pending a decision on the merits and denied the EPA's motion to transfer our challenge to the D.C. Circuit Court. As a result of the stay, we do not believe the EPA has authority to implement the FIP as to Texas sources pending the resolution of the merits, meaning that Texas will remain in Group 2 and not be subject to any requirements under the FIP at least until the Fifth Circuit Court rules on the merits. Oral argument was heard in December 2023 before the Fifth Circuit Court. In June 2023, the EPA published the final FIP in the Federal Register, which included requirements as to Texas despite the stay of the SIP disapproval by the Fifth Circuit Court. In June 2023, the State of Texas, Luminant and various other parties also filed challenges to the FIP in the Fifth Circuit Court, filed a motion to stay the FIP and confirm venue for this dispute in the Fifth Circuit Court. After the motion to stay and to confirm venue was filed, the EPA signed an interim final rule on June 29, 2023 that confirms the FIP as to Texas is stayed. In July 2023, the Fifth Circuit Court ruled that the FIP challenge would be held in abeyance pending the resolution of the litigation on the SIP disapproval and denied the motion to stay as not needed given the EPA's administrative stay.

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 generation 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 is in the process of reconsidering the BART rule, and the challenges in the D.C. Circuit Court have been held in abeyance pending the EPA's final action on reconsideration. In May 2023, a proposed BART rule was published in the Federal Register that would withdraw the trading program provisions of the prior rule and would establish SO_2 limits on six facilities in Texas, including Martin Lake and Coleto Creek. Under the current proposal, compliance would be required within 3 years for Martin Lake and 5 years for Coleto Creek. Due to the announced shutdown for Coleto Creek, we do not anticipate any impacts at that facility, and we are evaluating potential compliance options at Martin Lake should this proposal become final. We submitted comments to the EPA on this proposal in August 2023.

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. In January 2024, in a split decision, the Fifth Circuit Court denied the petitions for review we and the State of Texas filed over EPA' 2016 nonattainment designation for SO_2 for the area around Martin Lake. As a result of this decision, the EPA's nonattainment designation – originally made in 2016 – remains in place. We anticipate the EPA will likely move forward with either proposing a federal plan for the area in light of an approved consent decree between the Sierra Club and the EPA that requires the EPA taking final action promulgating a FIP for the nonattainment area by December 13, 2024 or the EPA may approve Texas' SIP submittal discussed above. In February 2024, we filed a petition asking the full Fifth Circuit Court to review the panel decision issued in January 2024.

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.

Particulate Matter

In February 2024, the EPA issued a 715-page rule addressing the annual health-based national ambient air quality standards for fine particulate matter (or PM2.5). In general, the rule lowers the level of the annual PM2.5 standard from 12.0 micrograms per cubic meter (µg/m3) to 9.0 µg/m3. The effective date of the rule is 60 days from publication in the Federal Register, and the earliest attainment date for areas exceeding the new standard is 2032. At this time, we are still determining what impact, if any, this rule will have on our existing plants or any plants we may build in the future. Based on 2020-2022 design value associated with the rule, we have just five plants (Oakland (California), Calumet (Illinois), Liberty (Pennsylvania), Miami Fort (Ohio) and Lake Hubbard (Texas)) operating in areas where the air quality monitoring data are currently exceeding the new PM2.5 standard. We have previously announced that our Miami Fort generation facility will close by the end of 2027. States will have to develop a plan (by late 2027 at the earliest) to get those areas into attainment and there would be a possibility that additional controls would be required for those sites. However, before the state begins this planning process, the designation process will occur within two years from the issuance of the final rule. The states develop recommendations about the boundaries of the nonattainment counties and the EPA must finalize the designations including the boundaries of each nonattainment area.

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.

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 2022 and 2023, we withdrew the applications for Coffeen, Martin Lake, Joppa and Zimmer stations because extensions were no longer needed. 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 application for an alternate liner demonstration for one CCR unit at Martin Lake, however, we withdrew the application for an alternate liner demonstration in November 2023 after determining the pond was no longer needed for CCR. In August 2021, we submitted a request to transfer our conversion application for the Zimmer facility to a retirement application following the 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 before the D.C. Circuit Court is complete, and the court will hear argument in March 2024.

In May 2023, the EPA issued another proposal that further revises the federal CCR rule that would expand coverage of groundwater monitoring and closure requirements to the following two new categories of units: (a) legacy units which are CCR impoundments at inactive sites that ceased receiving waste before October 19, 2015 and (b) so-called "CCR management units" which generally could encompass areas of CCR located at a facility that is currently regulated by the existing CCR rule. CCR Management Units, as defined by the EPA in the proposal, could include any ash deposits, haul roads, and previously closed impoundments and landfills. As part of the proposed rule, the EPA identified 134 CCR management units at 82 different facilities across the country, including six of our potential units. The Vermilion ash ponds discussed below are the only unit which we believe qualify as a legacy CCR surface impoundment and given our closure plan for that site we do not believe this proposal, if finalized, will have any impact on that site. We are continuing to evaluate what would be required of the CCR management units identified in the proposal should the proposal become final in its current form. We submitted comments in July 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. In July 2023, PRN filed an unopposed motion to voluntarily dismiss the case with prejudice, which the IPCB granted in August 2023 and closed the case.

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. In June 2023, the Illinois state court approved and entered the final consent order, which included the terms above and a requirement that when IEPA issues a final closure permit for the site, DMG will demolish the power station and submit for approval to construct an on-site landfill within the footprint of the former plant to store and manage the coal ash. These proposed closure costs are reflected in the ARO in our consolidated balance sheets (see Note 22 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 was filed for our Baldwin facility in August 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 CCR surface impoundment and landfill closure costs currently reflected in our existing ARO liabilities, reflect the costs of closure methods that our operations and environmental services teams believe are appropriate based on existing closure requirements and protective of the environment for each location. Once the IEPA acts on our permit applications, we will reassess the decommissioning costs and adjust our ARO liabilities accordingly.

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. 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. In March 2023, the EPA published its proposed supplemental ELG rule, which retains the retirement exemption from the 2020 ELG rule and sets new limits for plants that are continuing to operate. The proposed rule also establishes pretreatment standards for combustion residual leachate, and we are currently evaluating the impact of those proposed requirements. We submitted comments on the proposal in May 2023.

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.

Corporate Information

Vistra is a Delaware corporation whose common stock is listed and trade on the NYSE. Our principal executive office is located at 6555 Sierra Drive, Irving, Texas 75039. The telephone number for our principal executive office is (214) 812-4600. We maintain a website located at *www.vistracorp.com*.

Available Information

We file our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to those reports with the SEC. You may obtain copies of these documents, free of charge, on the SEC's website at *www.sec.gov* or on Vistra's website at *www.vistracorp.com*, as soon as reasonably practicable after they have been filed with or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended. Vistra also posts important information, including press releases, investor presentations, sustainability reports, and notices of upcoming events on its website and utilizes its 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 our website by signing up for email alerts and RSS feeds on the "Investor Relations" page. The information on Vistra's website shall not be deemed a part of, or incorporated by reference into, this annual report on Form 10-K.

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, battery 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.

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, or the repeal of existing beneficial 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.
- Cybersecurity attacks or technology systems failures could disrupt business operations and expose us to significant liabilities, reputational damage, loss of customers, and regulatory action.
- 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 may materially adversely affect our business.
- Changes in technology, increased electricity conservation efforts, or energy sustainability efforts may reduce the value of our business, introduce new or emerging risks 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 (MD&A)*, 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 MD&A 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 oil, 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, and Winter Storm Heather, in January 2024, were other examples 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 or other potential restrictions on Russian energy deliveries. See Item 7. *Management's Discussion and Analysis of Financial Condition, and Results of Operations – Significant 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 few 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 power 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 power 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 power 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 Market 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 have been and are 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 generation 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 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 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, elevated 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 battery ESS; 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. Our Vistra Operations Credit Agreement contains 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. Limitations 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 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, 2023, we had approximately $14.4 billion of total indebtedness and approximately $10.9 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 common and preferred 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.

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 obligations are required to be secured by letters of credit, surety bonds, first liens, 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 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, letters of credit and first liens 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, the use of first lien collateral, 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 is typically 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 enough 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.

The Transactions (as defined below) remain subject to customary closing conditions which, if not satisfied or waived, would delay the Transactions or adversely impact our ability to complete the Transactions on the terms set forth in the Transaction Agreement (as defined below) or at all.

The completion of the Transactions remain subject to the satisfaction or waiver of customary closing conditions. These closing conditions may not be fulfilled in a timely manner or at all, and, accordingly, the Transactions may not be completed.

If we are unable to complete the Transactions, we still will incur and will remain liable for significant transaction costs, including legal, accounting, advisory and other costs relating to the Transactions. Also, depending upon the reasons for not completing the Transactions, we may be required to pay Energy Harbor a termination fee of $225 million. If such a termination fee is payable, the payment could affect Vistra's share price.

Failure to consummate the Transactions as currently contemplated or at all could adversely affect the price of Vistra's common stock and our future business and financial results.

We cannot guarantee when or if these conditions will be satisfied or that the Transactions will be successfully completed. If the Transactions are not consummated, or are consummated on different terms than as contemplated by the Transaction Agreement, we could be adversely affected and subject to a variety of risks associated with the failure to consummate the Transactions, or to consummate the Transactions as contemplated by the Transaction Agreement, including:

- our stockholders may be prevented from realizing the anticipated potential benefits of the Transactions;
- the market price of our common stock could decline significantly;
- reputational harm due to the adverse public perception of any failure to successfully complete the Transactions;

- under certain circumstances, we may be required to pay Energy Harbor a termination fee of up to $225 million or reimburse Energy Harbor's expenses up to $20 million; and
- the attention of our management and employees may be diverted from their day-to-day business and operational matters and our relationships with our customers and suppliers may be disrupted as a result of efforts relating to attempting to consummate the Transactions.

Any delay in the consummation of the Transactions, any uncertainty about the consummation of the Transactions on terms other than those contemplated by the Transaction Agreement and any failure to consummate the Transactions could adversely affect our business, financial results and common stock price.

Following the completion of the Transactions, we may be unable to successfully integrate Energy Harbor's businesses with Vistra's nuclear and retail businesses and its Vistra Zero renewable and battery ESS projects or realize the anticipated synergies and other expected benefits of the Transactions on the anticipated timeframe or at all.

The Transactions involve the combination of Energy Harbor's nuclear and retail businesses with Vistra's nuclear and retail businesses and certain of Vistra Zero renewables and battery ESS projects under Vistra Vision. This new combination expects to benefit from certain cost savings, operating efficiencies and a growing renewables and battery ESS portfolio, some of which will take time to realize. We will be required to devote significant management attention and resources to the integration of our and Energy Harbor's business practices and operations into Vistra Vision. The potential difficulties we may encounter in building Vistra Vision include the following:

- the inability to successfully combine our nuclear, retail, renewables and battery storage business and Energy Harbor's nuclear and retail businesses in a manner that permits Vistra Vision to achieve the cost savings anticipated to result from the Transactions, which would result in the anticipated benefits of the Transactions not being realized in the timeframe currently anticipated or at all;
- the complexities associated with maintaining the second-largest competitive nuclear fleet in the U.S.;
- the complexities of combining two companies with different histories, geographic footprints and asset mixes;
- the complexities in combining two companies with separate technology systems;
- potential unknown liabilities and unforeseen increased expenses, delays or conditions associated with the Transactions;
- failure to perform by third-party service providers who provide key services for the combined company; and
- performance shortfalls as a result of the diversion of management's attention caused by completing the Transactions and integrating the companies' operations.

For all these reasons, it is possible that the integration process could result in the distraction of our management, the disruption of our ongoing business or inconsistencies in operations, services, standards, controls, policies and procedures, any of which could adversely affect our ability to maintain relationships with operators, vendors and employees, to achieve the anticipated benefits of the Transactions, or could otherwise materially and adversely affect its business and financial results.

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 Company's 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, battery 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 battery ESS. 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. FERC and regional ISOs are working to address these backlogs, including with potential regulatory rule changes, which would change the interconnection process, the results of which are currently unknown. Additionally, the increased demand for construction of renewables projects, such as battery ESS 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 battery ESS 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 2023 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.

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.

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, emissions 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 current presidential administration or during any future change of administration, or any repeal of existing beneficial laws or regulations, 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, Texas Public Utility Regulatory Act, 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, Ambit's direct selling business (i) could be found by 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. Winter Storm Elliott, in December 2022, 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 investigations 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 of 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. Changes enacted by the Texas Legislature through Senate Bill 2627, the Powering Texas Forward Act, to administer Texas Energy Fund (TEF) programs, which include grants and loans to finance the construction, maintenance, modernization, and operation of electric facilities in Texas, may negatively impact our financial condition if it materially changes market fundamentals. 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 generation 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 Good Neighbor Plan for the 2015 Ozone NAAQS, May 2023 proposal to regulated GHG emissions that would 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 continuing emphasis nationally and internationally on 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 generation 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 is in the process of developing 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 $245 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, 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 of additional regulatory investigations or administrative proceedings. As we adopt new technologies, like artificial intelligence (AI), there is a risk that the content, analyses, recommendations, or judgments that AI applications assist in producing are alleged to be deficient, inaccurate, biased, or infringe on other's rights or property interests. Any such regulatory investigation or administrative proceeding could result in us incurring penalties and other costs which may have a material 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, transmission and distribution outages, demand-side management programs, competition and economic conditions, or extreme weather events, 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 where our retail operation faces significant competition for customers. We believe our brands are viewed favorably in these markets, 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. Competitors may also incorporate AI into their businesses, services, and products more quickly or more successfully than we do. In retail markets with substantial competition, high customer acquisition costs may outweigh the potential margin and 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.

Cybersecurity attacks or technology systems failures could disrupt business operations and expose us to significant liabilities, reputational damage, loss of customers, and regulatory action.

Our businesses depend on the secure and reliable storage, processing and communication of electronic data and sophisticated computer hardware and software systems. Our information technology systems and infrastructure, and those of our vendors and suppliers, face constant threats that have in the past and could in the future compromise data confidentiality, integrity, or availability. While we have controls in place designed to protect our information technology (IT) infrastructure, such breaches and threats are becoming increasingly sophisticated and complex, requiring the continuing evolution of our program. A breach or similar IT incident could interrupt normal business operations and affect our ability to use our generation assets, customer information, or communication systems, which could have a material adverse effect on us.

Potential disruptions from cyber/data and physical security breaches to "critical cyber assets" that interrupt the delivery of power to the Bulk Electric System could incur penalties of up to $1 million per violation for failure to comply with mandatory electric reliability standards by FERC under the Energy Policy Act of 2005.

Further, our retail business requires us to regularly access, collect, store, and transmit customer data, including sensitive customer data. New data privacy and data protection laws and regulations, increased enforcement, and other government actions could impact our businesses and failure to comply with them could adversely affect our business and financial results. Our retail business may need to provide access to customer data, including sensitive customer data, to third parties and service providers to provide services, such as call center operations. Under new data protection laws, in certain circumstances, Vistra could incur liability for a third-party or service provider's misuse or loss of the data.

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 Federal Bureau of Investigation (FBI) and the U.S. Cybersecurity & Infrastructure Security Agency, issuing warnings of increased cyber threats, particularly for U.S. critical infrastructure. As of the date of this report, the Company has not identified a cyber/data event causing any material operational, reputational or financial impact. However, we recognize the growing threat within the general marketplace and our industry, especially as generative AI becomes more widely used by threat actors. There is no assurance that we will be able to prevent any such impacts in the future. In the event of a material cyber breach, critical operational capabilities to support our generation, commercial, or retail operations could be disrupted or lost. Additionally, customer, confidential, or proprietary data could be compromised, misused, or inappropriately disclosed. If critical operational capabilities or data were impacted, it could adversely affect our reputation, diminish customer confidence, expose us to legal or regulatory claims, impair our business strategy, or impact our results of operation or financial condition, which could have a material adverse effect on us. Our efforts to deter, identify, and mitigate future breaches may require additional, significant capital and operating costs 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 (see Item 7. *Management's Discussion and Analysis of Financial Condition, and Results of Operations – Significant Activities and Events, and Items Influencing Future Performance – Macroeconomic Conditions*);
- 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 generation 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 cybersecurity attacks, including nation-state attacks or organized cybercrime 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. 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 generation 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 new GHG rule expected to be finalized this year and the PM2.5 NAAQS rule released this year along with other NAAQS that may be issued in the future have the potential to adversely impact our natural 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 or state agencies. 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 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 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 business, introduce new or emerging risks, and may otherwise have a material adverse effect on us.

If we cannot adopt technological developments on a timely basis, demand for our services may decline, or we may face challenges in implementing or evolving our business strategy. Significant technological changes continue to impact our industry. To grow and remain competitive, we will need to adapt to changes in available technology like generative AI, continually invest in our assets, increase generation capacity, increase our use of renewable technologies, enhance our existing offerings, and introduce new offerings to meet our current and potential customers' changing service demands. Competitors may incorporate AI into their businesses, services, and products more quickly or more successfully than we do. Adopting new and sophisticated technologies may result in implementation issues, such as scheduling and supplier delays, unexpected or increased costs, technological constraints, regulatory issues, customer dissatisfaction, and other issues that could cause delays in launching new technological capabilities, which in turn could result in significant costs or reduce the anticipated benefits of the upgrades. As we adopt new technologies, like AI, there is a risk that the content, analyses, recommendations, or judgments that AI applications assist in producing are alleged to be deficient, inaccurate, biased, or infringe on other's rights or property interests. Our new services could fail to retain or gain acceptance in the marketplace, or costs associated with these services could be higher than anticipated. As such, our adoption of technology or failure to adopt technology could have a material adverse effect on our business, brand, financial condition, business strategy, and operating results.

Technological advances have improved, and are likely to continue to improve, for existing and alternative methods to produce and store power, including natural 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. Potential difficulties in attracting and retaining highly qualified, skilled employees could 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, 2023, we had approximately 1,200 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 2024 and March 2028, 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, coal and/or other 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.

The Board has 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.

The Board has approved a share repurchase program in an aggregate authorized amount of $5.75 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, 2023, 1,000,000 shares of Series A Preferred Stock, 1,000,000 shares of Series B Preferred Stock, and 476,081 shares of Series C 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, Series B Preferred Stock, and Series C 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, the holders of at least two-thirds of the outstanding Series B Preferred Stock and the holders of at least two-thirds of the outstanding Series C Preferred Stock, each 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, the holders of at least two-thirds of the outstanding Series B Preferred Stock and the holders of at least two-thirds of the outstanding Series C 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. The dividend rate for the Series C Preferred Stock from and including the initial issuance date of December 29, 2023 until the first reset date of January 15, 2029 will be 8.875% per annum of the $1,000 liquidation preference per share of Series C 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%. On and after the first reset date of the Series C Preferred Stock, the dividend rate on the Series C Preferred Stock for each Reset Period will be adjusted based upon the applicable Treasury rate, plus a spread of 5.045% per annum; provided that the applicable Treasury rate for each Reset Period will not be lower than 3.830%. 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%.

Item 1B. UNRESOLVED STAFF COMMENTS

None.

Item 1C. CYBERSECURITY

The Company has a cybersecurity and incident response program designed to assess, identify, and manage material risks from cybersecurity threats, including matters related to the cybersecurity of the Company's critical infrastructure, data, or information technology systems and the Company's actions to prepare for, identify, assess, respond, mitigate and remediate material cyber, information security, or technology risks (collectively referred to as Information Security). This program includes:

- operating a Cyber Security Operations Center;
- raising employee awareness through annual general and job-specific cybersecurity trainings and employee phishing simulations;
- maintaining defined cyber incident response plans;
- enhancing security measures to protect our systems and data;
- evolving monitoring capabilities to improve early detection and rapid response to potential cyber threats; and
- adapting to new work environments that include off-site work through mitigation of remote network risk to our internal systems, assets, or data.

Cybersecurity represents an important component of the Company's overall approach to enterprise risk management and is integrated into the risk management process and ongoing assessment. In addition to an internal security program, we strive to stay ahead of the threat landscape by working to conduct due diligence on key third-party vendors' Information Security programs and risks. We make strategic investments in our perimeter and internal defenses, cyber security operations center, and regulatory compliance activities with the advice of consultants and third parties. Moreover, to minimize risk, we maintain an insurance policy that provides coverage for matters relating to Information Security.

Vistra's Chief Information Officer (CIO) ensures Information Security is built into the Company's larger technology strategy and oversees our Chief Information Security Officer (CISO). Our CISO and his Information Security team are responsible for leading the enterprise-wide information security strategy, policy, standards, architecture, and processes and our Cyber Incident Response Teams under the CISO are responsible for monitoring and analyzing the Company's cybersecurity posture in partnership with Risk and Legal.

The CIO and CISO collaborate with our internal audit department and external consultants to review information technology-related risks (based upon the National Institute of Standards and Technology (NIST) Cybersecurity Framework) as part of the overall Vistra cyber risk management process. Through these processes, the CIO and CISO are informed about and monitor the prevention, detection, mitigation and remediation of cybersecurity threats.

We also participate in industry groups and with regulators to gain additional knowledge, including, but not limited to, the Federal Bureau of Investigation, U.S. Cybersecurity and Infrastructure Security Agency, U.S. Department of Homeland Security, Electricity Information Sharing and Analysis Center, U.S. Cyber Emergency Response Team, the NRC and NERC. We apply the knowledge gained through industry partnerships, government organizations, external cyber risk platforms, and program maturity assessments to improve our processes to detect and mitigate cyber threats.

As of the date of this report, we have not identified any impacts from cybersecurity threats, including those from any previous cybersecurity incidents, that have materially affected our results of operation or financial condition. However, despite our efforts, we cannot eliminate all risks from cybersecurity threats, or provide assurances that we have not experienced undetected cybersecurity incidents. For additional information on risks from cybersecurity threats, see Item 1A. *Risk Factors*.

While the Board has established a separate Risk and Sustainability Committee to oversee enterprise risk processes, the Board maintains oversight of Vistra's Information Security. Vistra engaged a third-party advisor to provide cybersecurity oversight and tabletop training to the full Board in 2023 to further our commitment to responsible oversight of cybersecurity risk management. At least quarterly, our CIO reports to the Board on our Information Security program, including cybersecurity risks and threats (including the emerging threat landscape), an assessment of our Information Security program, and the status of projects to strengthen our Information Security program. In furtherance of our commitment to responsible oversight of cybersecurity risk management, in 2023, the Board appointed a director who brings extensive cybersecurity expertise to the Board.

Our CIO serves as head of Vistra's Technology Services and is responsible for ensuring the reliability, security, and continued development of the Company's technology platforms and delivering new solutions to support the business. The CIO has served in various senior information technology roles in public companies for over 30 years, including Keurig Dr. Pepper Inc., General Motors, Pfizer, and Electronic Data Systems.

Our CISO also has over 35 years of information technology experience. He is a 10-year U.S. Air Force veteran and has held technology positions in infrastructure management and operations with Raytheon and Blockbuster. He also maintains Certified Information Systems Security Professional (CISSP) and Certified Information Security Manager (CISM) certifications.

Item 2. PROPERTIES

The following table presents our asset fleet as of December 31, 2023 by segment. All of our facilities are 100% (fee simple) owned.

Facility	Location	ISO/RTO	Technology	Primary Fuel	Net Capacity (MW) (a)
Texas Segment					
Ennis	Ennis, TX	ERCOT	CCGT	Natural Gas	366
Forney	Forney, TX	ERCOT	CCGT	Natural Gas	1,912
Hays	San Marcos, TX	ERCOT	CCGT	Natural Gas	1,047
Lamar	Paris, TX	ERCOT	CCGT	Natural Gas	1,076
Midlothian	Midlothian, TX	ERCOT	CCGT	Natural Gas	1,596
Odessa	Odessa, TX	ERCOT	CCGT	Natural Gas	1,054
Wise	Poolville, TX	ERCOT	CCGT	Natural Gas	787
Martin Lake	Tatum, TX	ERCOT	ST	Coal	2,250
Oak Grove	Franklin, TX	ERCOT	ST	Coal	1,600
DeCordova	Granbury, TX	ERCOT	CT	Natural Gas	260
Graham	Graham, TX	ERCOT	ST	Natural Gas	630
Lake Hubbard	Dallas, TX	ERCOT	ST	Natural Gas	921
Morgan Creek	Colorado City, TX	ERCOT	CT	Natural Gas	390
Permian Basin	Monahans, TX	ERCOT	CT	Natural Gas	325
Stryker Creek	Rusk, TX	ERCOT	ST	Natural Gas	685
Trinidad	Trinidad, TX	ERCOT	ST	Natural Gas	244
Comanche Peak (b)	Glen Rose, TX	ERCOT	Nuclear	Nuclear	2,400
Brightside	Live Oak County, TX	ERCOT	Solar	Renewable	50
Emerald Grove	Crane County, TX	ERCOT	Solar	Renewable	108
Upton 2	Upton County, TX	ERCOT	Solar/ Battery	Renewable	190
DeCordova	Granbury, TX	ERCOT	Battery	Renewable	260
Total Texas Segment					**18,151**

Facility	Location	ISO/RTO	Technology	Primary Fuel	Net Capacity (MW) (a)
East Segment					
Fayette	Masontown, PA	PJM	CCGT	Natural Gas	726
Hanging Rock	Ironton, OH	PJM	CCGT	Natural Gas	1,430
Hopewell	Hopewell, VA	PJM	CCGT	Natural Gas	370
Kendall	Minooka, IL	PJM	CCGT	Natural Gas	1,288
Liberty	Eddystone, PA	PJM	CCGT	Natural Gas	607
Ontelaunee	Reading, PA	PJM	CCGT	Natural Gas	600
Sayreville	Sayreville, NJ	PJM	CCGT	Natural Gas	349
Washington	Beverly, OH	PJM	CCGT	Natural Gas	711
Calumet	Chicago, IL	PJM	CT	Natural Gas	380
Dicks Creek	Monroe, OH	PJM	CT	Natural Gas	155
Miami Fort (CT)	North Bend, OH	PJM	CT	Fuel Oil	77
Pleasants	Saint Marys, WV	PJM	CT	Natural Gas	388
Richland (c)	Defiance, OH	PJM	CT	Natural Gas	423
Stryker (c)	Stryker, OH	PJM	CT	Fuel Oil	16
Bellingham	Bellingham, MA	ISO-NE	CCGT	Natural Gas	566
Blackstone	Blackstone, MA	ISO-NE	CCGT	Natural Gas	544
Casco Bay	Veazie, ME	ISO-NE	CCGT	Natural Gas	543
Lake Road	Dayville, CT	ISO-NE	CCGT	Natural Gas	827
Masspower	Indian Orchard, MA	ISO-NE	CCGT	Natural Gas	281
Milford	Milford, CT	ISO-NE	CCGT	Natural Gas	600
Independence	Oswego, NY	NYISO	CCGT	Natural Gas	1,212
Total East Segment					**12,093**
West Segment					
Moss Landing 1 & 2	Moss Landing, CA	CAISO	CCGT	Natural Gas	1,020
Moss Landing	Moss Landing, CA	CAISO	Battery	Renewable	750
Oakland	Oakland, CA	CAISO	CT	Fuel Oil	110
Total West Segment					**1,880**
Sunset Segment					
Coleto Creek	Goliad, TX	ERCOT	ST	Coal	650
Baldwin	Baldwin, IL	MISO	ST	Coal	1,185
Newton	Newton, IL	MISO	ST	Coal	615
Kincaid	Kincaid, IL	PJM	ST	Coal	1,108
Miami Fort 7 & 8	North Bend, OH	PJM	ST	Coal	1,020
Total Sunset Segment					**4,578**
Total capacity					**36,702**

(a) Approximate net generation capacity. Actual net generation capacity may vary based on a number of factors, including ambient temperature. We have not included units that have been retired or are out of operation.
(b) In October 2022, we announced the submission of our application to the NRC for license renewal at our two-unit Comanche Peak Nuclear Plant. The current licenses for Units 1 and 2 extend into 2030 and 2033, respectively, and we are applying to renew the licenses into 2050 and 2053, respectively.
(c) We have entered into an agreement to sell the Richland and Stryker generation facilities, and closing is expected in early March 2024.

See Note 3 to the Financial Statements for discussion of our solar and battery energy storage projects currently under development and Note 4 to the Financial Statements for discussion of our retirement of certain generation facilities, including the Zimmer, Joppa and Edwards generation facilities that we retired in June 2022, September 2022 and January 2023, respectively, that are reported in our Asset Closure segment and excluded from the table above.

Our wholesale commodity risk management group also procures renewable energy credits from renewable generation in ERCOT to support our electricity sales to wholesale and retail customers to satisfy the increasing demand for renewable resources from such customers. As of December 31, 2023, Vistra had long-term agreements to procure renewable energy credits from approximately 885 MW of renewable generation. These renewable generation sources deliver electricity when conditions make them available, and, when on-line, they generally compete with baseload units. Because they cannot be relied upon to meet demand continuously due to their dependence on weather and time of day, these generation sources are categorized as non-dispatchable and create the need for intermediate/load-following resources to respond to changes in their output.

Item 3. LEGAL PROCEEDINGS

See Note 14 to the Financial Statements for discussion of material litigation matters to which Vistra is a party.

Item 4. MINE SAFETY DISCLOSURES

Vistra currently owns and operates, or is in the process of reclaiming, 12 surface lignite coal mines in Texas to provide fuel for its electricity generation facilities. Vistra also owns or leases, and is in the process of reclaiming, two waste-to-energy surface facilities in Pennsylvania. These mining operations are regulated by the MSHA under the Federal Mine Safety and Health Act of 1977, as amended (the Mine Act), as well as other federal and state regulatory agencies such as the RCT and Office of Surface Mining. The MSHA inspects U.S. mines, including Vistra's mines, on a regular basis, and if it believes a violation of the Mine Act or any health or safety standard or other regulation has occurred, it may issue a citation or order, generally accompanied by a proposed fine or assessment. Such citations and orders can be contested and appealed, which often results in a reduction of the severity and amount of fines and assessments and sometimes results in dismissal. Disclosure of MSHA citations, orders and proposed assessments are provided in Exhibit 95.1 to this annual report on Form 10-K.

PART II

Item 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Vistra's common stock is listed and traded on the NYSE under the symbol "VST". Vistra's authorized capital stock consists of 1,800,000,000 shares of common stock with a par value of $0.01 per share.

As of February 23, 2024, there were 472 stockholders of record.

The Board has authority to declare dividends to the holders of our common stock. The Board intends to continue the payment of dividends to the holders of the Company's common stock in the future. The declaration and payment of future dividends, however, will be at the discretion of the Board and will depend on numerous factors in existence at the time of any such declaration including, but not limited to, prevailing market conditions, Vistra's results of operations, financial condition and liquidity, Delaware law and contractual limitations.

Stock Performance Graph

The performance graph below compares Vistra's cumulative total return on common stock during the five-year period from December 31, 2018 through December 31, 2023 with the cumulative total returns of the S&P 500 Stock Index (S&P 500) and the S&P Utility Index (S&P Utilities). The graph below compares the return in each period assuming that $100 was invested at December 31, 2018 in Vistra's common stock, the S&P 500 and the S&P Utilities, and that all dividends were reinvested.

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	December 31,					
	2018	2019	2020	2021	2022	2023
Vistra Corp.	$ 100.00	$ 102.48	$ 90.41	$ 108.08	$ 113.57	$ 193.89
S&P 500	$ 100.00	$ 131.47	$ 155.65	$ 200.59	$ 163.98	$ 207.04
S&P Utilities	$ 100.00	$ 126.35	$ 127.01	$ 149.46	$ 151.79	$ 141.05

The stock price performance included in this graph is not necessarily indicative of future stock price performance.

Purchases of Equity Securities by the Issuer

The following table provides information about our repurchase of common stock, during the three months ended December 31, 2023.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of a Publicly Announced Program	Maximum Dollar Amount of Shares that may yet be Purchased under the Program (in millions)
October 1 - October 31, 2023	4,246,310	$ 32.15	4,246,310	$ 993
November 1 - November 30, 2023	3,682,876	$ 34.81	3,682,876	$ 865
December 1 - December 31, 2023	3,061,650	$ 37.55	3,061,650	$ 750
For the quarter ended December 31, 2023	10,990,836	$ 34.54	10,990,836	$ 750

In October 2021, we announced that the Board had authorized a share repurchase program (Share Repurchase Program) under which up to $2.0 billion of our outstanding common stock may be repurchased. The Share Repurchase Program became effective on October 11, 2021. In August 2022, March 2023 and February 2024, the Board authorized incremental amounts of $1.25 billion, $1.0 billion and $1.5 billion, respectively, for repurchases to bring the total authorized under the Share Repurchase Program to $5.75 billion. We expect to complete repurchases under the Share Repurchase Program by the end of 2025.

See Note 15 to the Financial Statements for more information concerning the Share Repurchase Program.

Item 6. [RESERVED]

Not applicable.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION, AND RESULTS OF OPERATIONS

The following discussion and analysis of our financial condition and results of operations should be read together with our consolidated financial statements and related notes included in Item 8. *Financial Statements and Supplementary Data*. See Item 7. *Management's Discussion and Analysis of Financial Condition, and Results of Operations* in our 2022 Form 10-K for a discussion of our financial condition and results of operations for the year ended December 31, 2021 and for the year ended December 31, 2022 compared to the year ended December 31, 2021, which is incorporated here by reference.

All dollar amounts in the tables in the following discussion and analysis are stated in millions of U.S. dollars unless otherwise indicated.

Significant Activities and Events, and Items Influencing Future Performance

Proposed Merger with Energy Harbor

On March 6, 2023, Vistra Operations and its wholly-owned subsidiary (Merger Sub) entered into a Transaction Agreement with Energy Harbor pursuant to which, upon the terms and subject to the conditions thereof, Merger Sub will be merged with and into Energy Harbor, with Energy Harbor surviving as an indirect subsidiary of Vistra. The Transaction Agreement, the Merger and the other Transactions were approved by each of Vistra's Board and Energy Harbor's board of directors. On February 16, 2024, we received approval from FERC to acquire Energy Harbor. FERC's approval was the last regulatory approval needed, and we anticipate closing on March 1, 2024. See Note 2 to the Financial Statements for more information concerning the Transaction Agreement.

Inflation Reduction Act of 2022

In August 2022, the U.S. enacted the IRA, which, among other things, implements substantial new and modified energy tax credits, including a nuclear PTC, a solar PTC, a first-time stand-alone battery storage investment tax credit, a 15% corporate alternative minimum tax (CAMT) on book income of certain large corporations, and a 1% excise tax on net stock repurchases. Treasury regulations are expected to further define the scope of the legislation in many important respects over the next twelve months. The excise tax on stock repurchases is not expected to have a material impact on our financial statements. Vistra is not subject to the CAMT in the 2023 tax year since it only applies to corporations that have a three-year average annual adjusted financial statement income in excess of $1 billion. We have taken the CAMT and relevant extensions or expansions of existing tax credits applicable to projects in our immediate development pipeline into account when forecasting cash taxes for periods after the law takes effect. See Note 1 for our accounting policy related to refundable and transferable PTCs and ITCs.

Repurchase of TRA Rights and Preferred Stock Issuance

On December 29, 2023, Vistra repurchased (Repurchase) approximately 74% of the outstanding beneficial interests in the TRA Rights to receive payments under the TRA from a select group of registered holders of the TRA Rights (Selling Holders) in exchange for consideration of $1.50 per repurchased TRA Right, totaling an aggregate purchase price for the Repurchase of approximately $476 million. The shares of Series C Preferred Stock were issued (see Note 15 to the Financial Statements) to the Selling Holders in exchange for the TRA Rights in a transaction exempt from registration pursuant to Section 4(a)(2) of the Securities Act. As part of the transaction, on January 29, 2024, the Company filed a shelf registration statement on Form S-3 registering the resale of the shares by the Selling Holders of Series C Preferred Stock from time to time under Rule 415 of the Securities Act. If the Company repurchases TRA Rights at any time during the 180 days following December 29, 2023 at a price per TRA Right greater than $1.50, the Company will pay the Selling Holders an amount equal to such excess purchase price per TRA Right sold by the Selling Holders.

On January 11, 2024, Vistra repurchased an additional 43,494,944 TRA Rights from a select group of registered holders of TRA Rights in exchange for consideration of $1.50 per repurchased TRA Right. Total consideration of $65 million was paid using cash on hand.

On January 31, 2024, Vistra announced a cash tender offer to purchase any and all outstanding TRA Rights in exchange for consideration of $1.50 per tendered TRA Right accepted for purchase prior to close of business on February 13, 2024 (Early Tender Date), which included an early tender premium of $0.05 per TRA Right accepted for purchase. As of the Early Tender Date, 55,056,931 TRA Rights were accepted for purchase for total consideration of $83 million, which was paid using cash on hand. TRA Rights accepted for purchase after the Early Tender Date, but prior to the close of business on February 28, 2024, will receive consideration of $1.45 per TRA Right accepted for purchase, which will be paid in March 2024 using cash on hand.

As of the Early Tender Date, we have repurchased an aggregate 98% of the original outstanding TRA Rights, of which 10,430,083 TRA Rights remain outstanding.

See Note 8 to the Financial Statements for details of the TRA and Note 15 to the Financial Statements for details of the Series C Preferred Stock.

Financial and Operating Performance

The following are financial and operating highlights we achieved in the execution of our four strategic priorities:

Long-term, attractive earnings profile through the integrated business model.

- We continued to execute our integrated business model through exceptional operational performance and capitalization of market opportunities which drove strong earnings during the year ended December 31, 2023, highlighting our competitive advantage of coupling retail with our reliable and efficient generation fleet and wholesale commodity risk management capabilities which reduces the effects of commodity price movements and contributes to the stability and predictability of our cash flows.
- Our commercial team focused on effectively and efficiently managing risk by opportunistically hedging for 2023 and beyond and optimizing our assets and business positions which led to strong plant operating performance and energy margins.

- Our retail brands served 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 through products and solutions that differentiate from our competitors leading to an increase in residential customer counts within markets we continue to operate.

Strategic energy transition that supports the reliability and affordability of electricity.

- In June 2023, an additional 350 MW battery ESS at our Moss Landing Power Plant site commenced commercial operations.
- As of June 30, 2023, the net proceeds of our Series B Preferred Stock were fully allocated to eligible solar and battery projects, pursuant to our Green Finance Framework.
- We continued development and construction activities on the planned development of 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.
- We retired our Edwards coal generation plant on January 1, 2023.

Significant and consistent shareholder return of capital.

- During the year ended December 31, 2023, we paid dividends to common stockholders totaling $313 million.
- During the year ended December 31, 2023, we repurchased 45 million shares for $1.3 billion under our stock repurchase program. Total shares repurchased under the program established in October 2021 are 143 million shares for $3.5 billion. See Note 15 to the Financial Statements for more information about our dividend and Share Repurchase Program.

Maintaining a strong balance sheet.

- In December 2023, we issued $400 million of 6.950% Senior Secured Notes due 2033 and $350 million of 7.750% Senior Unsecured Notes due 2031 in which the net proceeds were used to fund the tender offer (Senior Secured Notes Tender Offer) to purchase for cash $759 million aggregate principal amount of certain notes in January 2024, including $58 million of 4.875% Senior Secured Notes due 2024, $345 million of 3.550% Senior Secured Notes due 2024 and $356 million of the 5.125% Senior Secured Notes due 2025.

During the year ended December 31, 2023, our operating segments delivered strong operating performance with a disciplined focus on cost management, while generating and selling essential electricity in a safe and reliable manner. Our performance reflected strong plant operating performance, summer scarcity pricing events in Texas and effectiveness of our comprehensive hedging strategy and the value we were able to lock in as forward power and natural gas curves increased beginning in 2022.

Macroeconomic Conditions

With forward power and natural gas curves increasing during 2022 and the continued volatility in 2023, we have increased our hedging for future periods. As of December 31, 2023, we have hedged approximately 91% of our expected generation volumes on average for the two-year period 2024 through 2025 (with approximately 98% hedged for 2024 and approximately 83% hedged for 2025).

The industry continues to experience supply chain constraints that have reduced the availability of certain equipment and supply relevant to construction of renewables projects, and increased the lead time to procure certain materials necessary to maintain our natural gas, nuclear and coal fleet. We are proactively managing the increased costs of materials and supply chain disruptions and continuing to prudently re-evaluate the business cases and timing of our planned development projects, which has resulted in a deferral of some of our planned capital spend for our renewables projects. In addition, we have proactively engaged our suppliers to secure key materials needed to maintain our existing generation facilities prior to future planned outages, and our Vistra Zero operational and development projects are anticipated to benefit from the impact of the IRA. The inflationary environment continues to drive elevated interest rates, resulting in increased expected refinancing or borrowing costs, including project financing for our development projects and refinancing expected in connection with debt due in 2024 and beyond.

We are closely monitoring developments in the Russia and Ukraine conflict, specifically with regards to, (i) sanctions (or potential sanctions) against Russian energy exports and Russian nuclear fuel supply and enrichment activities, and (ii) actions by Russia to limit energy deliveries, which may further impact commodity prices in Europe and globally. In addition, current policies being considered by the U.S. Congress, namely H.R. 1042 the Prohibiting Russian Uranium Imports Act, would restrict imports of uranium if signed into law. The bill passed out of the House of Representatives in December 2023, and the future of the bill remains uncertain as it awaits consideration in the Senate. Our 2024 refueling has not been affected by the Russia and Ukraine conflict, nor have we seen any disruption to the delivery of nuclear fuel. We are taking affirmative action by building strategic inventory and deploying mitigating strategies in our procurement portfolio to ensure we can secure the nuclear fuel needed to continue to operate our nuclear facility through potential Russian supply disruption. We work with a diverse set of global nuclear fuel cycle suppliers to procure our nuclear fuel years in advance, and therefore, we expect to have enough nuclear fuel to support all our refueling needs, including the Energy Harbor facilities following the expected closing of the Transactions, through 2027. If imports from Russia are restricted, refueling operations of U.S. merchant nuclear power generators could be challenged in future years.

Capacity Markets

PJM, NYISO, ISO-NE, MISO and CAISO ensure long-term grid reliability through monthly, semiannual, annual and multi-year capacity auctions or bilateral transactions where power suppliers commit to making the generation resources available to the ISO as needed for a specific time period. We participate in these capacity market auctions and also enter into bilateral capacity sales, and a portion of our East, West and Sunset segment revenues are impacted by the capacity auction results or bilateral contracts. The following information summarizes the auction pricing for zones in which we operate as well as our capacity auction and bilateral capacity sales by planning period. Performance incentive rules 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.

PJM

Reliability Pricing Model (RPM) auction results, for the zones in which our assets are located, are as follows for each planning year:

	2023-2024	2024-2025
	(average price per MW-day)	
RTO zone	$ 34.13	$ 28.92
ComEd zone	34.13	28.92
MAAC zone	49.49	49.49
EMAAC zone	49.49	54.95
ATSI zone	34.13	28.92
DEOK zone	34.13	96.24

Our capacity sales in PJM, net of purchases, aggregated by planning year and capacity type through planning year 2024-2025, are as follows:

	2023-2024		2024-2025	
	East Segment	Sunset Segment	East Segment	Sunset Segment
CP auction capacity sold, net (MW)	5,811	1,667	5,567	1,338
Bilateral capacity sold, net (MW)	378	166	400	38
Total segment capacity sold, net (MW)	6,189	1,833	5,967	1,376
Average price per MW-day	$ 38.61	$ 36.82	$ 36.80	$ 75.11

NYISO

The most recent seasonal auction results for NYISO's Rest-of-State zones, in which the capacity for our Independence plant clears, are as follows for each planning period:

	Winter 2023 - 2024
Price per kW-month	$ 3.83

Due to the short-term, seasonal nature of the NYISO capacity auctions, we monetize the majority of our capacity through bilateral trades. Our capacity sales, aggregated by season through winter 2025-2026, are as follows:

	East Segment				
	Winter 2023 - 2024	Summer 2024	Winter 2024 - 2025	Summer 2025	Winter 2025 - 2026
Auction capacity sold (MW)	12	—	—	—	—
Bilateral capacity sold (MW)	1,132	873	591	175	59
Total capacity sold (MW)	1,144	873	591	175	59
Average price per kW-month	$ 2.27	$ 3.80	$ 3.44	$ 4.10	$ 4.10

ISO-NE

The most recent Forward Capacity Auction results for ISO-NE Rest-of-Pool, in which most of our assets are located, are as follows for each planning year:

	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
Price per kW-month	$ 2.00	$ 2.61	$ 2.59	$ 2.59	$ 3.58

We continue to market and pursue longer term multi-year capacity transactions that extend through planning year 2027-2028.

	East Segment				
	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
Auction capacity sold (MW)	3,213	3,103	3,032	2,836	3,261
Bilateral capacity sold (MW)	22	78	78	58	8
Total capacity sold (MW)	3,235	3,181	3,110	2,894	3,269
Average price per kW-month	$ 2.22	$ 3.12	$ 2.72	$ 2.60	$ 3.58

MISO

The capacity auction results for MISO Local Resource Zone 4, in which our assets are located, are as follows for each planning year:

	2023-2024
Price per MW-day	$ 9.25

MISO capacity sales through planning year 2026-2027 are as follows:

	Sunset Segment			
	2023-2024	2024-2025	2025-2026	2026-2027
Bilateral capacity sold in MISO (MW)	1,702	984	423	101
Total MISO segment capacity sold (MW)	1,702	984	423	101
Average price per kW-month	$ 4.36	$ 4.34	$ 4.94	$ 4.59

CAISO

Our capacity sales as part of the California Public Utilities Commission Resource Adequacy (RA) Program in California, aggregated by calendar year for 2024 through 2027 for Moss Landing, are as follows:

	West Segment			
	2024	2025	2026	2027
Bilateral capacity sold (Avg MW)	1,880	1,770	1,250	750

Electricity Prices

The price of electricity has a significant impact on our operating revenues and purchased power costs. Electricity prices are typically set by the cost to fuel a generation facility and the amount of fuel needed to generate one unit of electricity (Heat Rate) from the generation facility. Market Heat Rate is the implied relationship between wholesale electricity prices and the commodity price of the marginal supplier (generally natural gas plants).

Wholesale electricity prices generally track to increases or decreases in the price of natural gas, with exceptions such as when ERCOT power prices rise significantly during weather events as a result of the scarcity of available generation resources relative to power demand. The price of natural gas is volatile; therefore, the costs to operate a natural gas-fueled generation facility can be volatile as well. In contrast to our natural gas-fueled generation facilities, changes in natural gas prices have no significant effect on the cost of generating power at our nuclear-, lignite- and coal-fueled facilities; however, all other factors being equal, changes in natural gas prices affect our operating margins on these facilities as electricity prices generally track to natural gas prices. Other variables that could impact electricity prices include, but are not limited to, the price of other fuels, generation resources in the region, weather, on-going competition, emerging technologies, and macroeconomic and regulatory factors.

The wholesale market price of electricity divided by the market price of natural gas represents the Market Heat Rate. Market Heat Rate can be affected by a number of factors, including generation availability, mix of assets and the efficiency of the marginal supplier (generally natural gas-fueled generation facilities) in generating electricity. Our Market Heat Rate exposure is impacted by changes in the availability of generation resources, such as additions and retirements of generation facilities, and mix of generation assets. For example, increasing renewable (wind and solar) generation capacity generally depresses Market Heat Rates, particularly during periods when total demand is relatively low. However, increasing penetration of renewable generation capacity may also contribute to greater volatility of wholesale market prices independent of changes in the price of natural gas, given their intermittent nature.

As a result of our exposure to the variability of natural gas prices and Market Heat Rates, retail sales and hedging activities are critical to our operating results and maintaining consistent cash flow levels. Our integrated power generation and retail electricity business provides us opportunities to hedge our generation position utilizing retail electricity markets as a sales channel. Our approach to managing electricity price risk focuses on the following:

- employing disciplined, liquidity-efficient hedging and risk management strategies through physical and financial energy-related contracts intended to partially hedge gross margins;
- continuing focus on cost management to better withstand gross margin volatility;
- following a retail pricing strategy that appropriately reflects the value of our product offering to customers, the magnitude and costs of commodity price, liquidity risk and retail demand variability; and
- improving retail customer service to attract and retain high-value customers.

Critical Accounting Estimates

We follow accounting principles generally accepted in the U.S. Application of these accounting policies in the preparation of our consolidated financial statements requires management to make estimates and assumptions about future events that affect the reporting of assets and liabilities at the balance sheet dates and revenues and expenses during the periods covered. The following is a summary of certain critical accounting estimates that are impacted by judgments and uncertainties and under which different amounts might be reported using different assumptions or estimation methodologies.

Derivative Instruments and Mark-to-Market Accounting

We enter into contracts for the purchase and sale of energy-related commodities, and also enter into other derivative instruments such as options, swaps, futures and forwards primarily to manage commodity price and interest rate risks. Under accounting standards related to derivative instruments and hedging activities, these instruments are subject to mark-to-market accounting, and the determination of market values for these instruments is based on numerous assumptions and estimation techniques.

Mark-to-market accounting recognizes changes in the fair value of derivative instruments in the financial statements as market prices change. Such changes in fair value are accounted for as unrealized mark-to-market gains and losses in net income with an offset to derivative assets and liabilities. The availability of quoted market prices in energy markets is dependent on the type of commodity (e.g., natural gas, electricity, etc.), time period specified and delivery point. Where quoted market prices are not available, the fair value is based on unobservable inputs, which require significant judgment. Derivative instruments valued based on unobservable inputs primarily include (i) forward sales and purchases of electricity (including certain retail contracts), natural gas and coal, (ii) electricity, natural gas and coal options, and (iii) financial transmission rights. In computing fair value for derivatives, each forward pricing curve is separated into liquid and illiquid periods. The liquid period varies by delivery point and commodity. Generally, the liquid period is supported by exchange markets, broker quotes and frequent trading activity. For illiquid periods, fair value is estimated based on forward price curves developed using proprietary modeling techniques that take into account available market information and other inputs that might not be readily observable in the market. Any significant changes to these inputs could result in a material change to the value of the assets or liabilities recorded on our consolidated balance sheets and could result in a material change to the unrealized gains or losses recorded in our consolidated statements of operations. We estimate fair value as described in Note 16 to the Financial Statements.

Accounting standards related to derivative instruments and hedging activities allow for normal purchase or sale elections, which generally eliminate the requirement for mark-to-market recognition in net income. Normal purchases and sales (NPNS) are contracts that provide for physical delivery of quantities expected to be used or sold over a reasonable period in the normal course of business and are not subject to mark-to-market accounting if the NPNS election is made and are accounted for on an accrual basis. Determining whether a contract qualifies for the normal purchase or sale election requires judgment as to whether or not the contract will physically deliver and requires that management ensure compliance with all associated qualification and documentation requirements. If it is determined that a transaction designated as a normal purchase or sale no longer meets the scope exception due to changes in estimates, the related contract would be recorded on the balance sheet at fair value with immediate recognition through earnings.

See Note 17 to the Financial Statements for further discussion regarding derivative instruments.

Accounting for Income Taxes

Our income tax expense and related consolidated balance sheet amounts involve significant management estimates and judgments. Amounts of deferred income tax assets and liabilities, as well as current and noncurrent accruals, involve estimates and judgments of the timing and probability of recognition of income and deductions by taxing authorities. Further, we assess the likelihood that we will be able to realize or utilize our deferred tax assets. If realization is not more likely than not, we would record a valuation allowance against such deferred tax assets for the amount we would not expect to utilize, which would reduce the carrying value of the deferred tax amounts. When evaluating the need for a valuation allowance, we consider all available positive and negative evidence, including the following:

- the creation and timing of future income associated with the reversal of deferred tax liabilities in excess of deferred tax assets;
- the existence, or lack thereof, of statutory limitations on the period that net operating losses may be carried forward; and
- the amounts and history of income or losses, adjusted for certain non-recurring items.

Actual income taxes could vary from estimated amounts due to the future impacts of various items, including changes in income tax laws, our forecasted financial condition and results of operations in future periods, as well as final review of filed tax returns by taxing authorities.

Income tax returns are regularly subject to examination by applicable tax authorities. In management's opinion, the liability recorded pursuant to income tax accounting guidance related to uncertain tax positions reflects future taxes that may be owed as a result of any examination.

See Notes 1 and 7 to the Financial Statements for further discussion of income tax matters.

Accounting for Tax Receivable Agreement (TRA)

On the Effective Date, Vistra entered into the TRA with a transfer agent. Pursuant to the TRA, we issued the TRA Rights for the benefit of the first-lien creditors of TCEH entitled to receive such TRA Rights under the Plan of Reorganization. Vistra reflected the obligation associated with TRA Rights at fair value in the amount of $574 million as of the Effective Date related to these future payment obligations. In December 2023, we repurchased approximately 74% of the TRA Rights to receive payments under the TRA from a select group of registered holders of the TRA Rights. Also, during the year ended December 31, 2023, we recorded an increase to the carrying value of the TRA obligation totaling $82 million as a result of adjustments to forecasted taxable income due to increases in longer-term commodity price forecasts. As of December 31, 2023, the TRA obligation has been adjusted to $171 million, and the expected undiscounted federal and state payments under the TRA is estimated to be approximately $350 million. After giving effect to the January 2024 additional repurchases and the January and February 2024 early tender offer repurchases, we have repurchased an aggregate 98% of the original outstanding TRA Rights, of which 10,430,083 TRA Rights remain outstanding as of the Early Tender Date.

The TRA obligation value is the discounted amount of projected payments to be made each year under the TRA, based on certain assumptions, including but not limited to:

- the amount of tax basis related to (i) the Lamar and Forney acquisition and (ii) step-up resulting from the PrefCo Preferred Stock Sale (which is estimated to be approximately $5.5 billion) and the allocation of such tax basis step-up among the assets subject thereto;
- the depreciable lives of the assets subject to such tax basis step-up, which generally is expected to be 15 years for most of such assets;
- a blended federal/state corporate income tax rate in all future years of 23.2%;
- future taxable income by year for future years;
- the Company generally expects to generate sufficient taxable income to be able to utilize the deductions arising out of (i) the tax basis step up attributable to the PrefCo Preferred Stock Sale, (ii) the entire tax basis of the assets acquired as a result of the Lamar and Forney Acquisition, and (iii) tax benefits related to imputed interest deemed to be paid by us as a result of payments under the TRA in the tax year in which such deductions arise;
- a discount rate of 15%, which represented our view at the Effective Date of the rate that a market participant would use based on the risk associated with the uncertainty in the amount and timing of the cash flows, at the time of Emergence; and
- additional states that Vistra now operates in, the relevant tax rates of those states and how income will be apportioned to those states.

There may be significant changes, which may be material, to the estimate of the related liability due to various reasons including changes in federal and state tax laws and regulations, changes in estimates of the amount or timing of future consolidated taxable income, utilization of acquired net operating losses, reversals of temporary book/tax differences and other items. Changes in those estimates are recognized as adjustments to the related TRA obligation, with offsetting impacts recorded in the consolidated statements of operations as Impacts of Tax Receivable Agreement. See Note 8 to the Financial Statements.

Asset Retirement Obligations (ARO)

As part of business combination accounting, new fair values were established for all AROs assumed in the Dynegy Merger. A liability is initially recorded at fair value for an ARO associated with the legal obligation associated with law, regulatory, contractual or constructive retirement requirements of tangible long-lived assets. These liabilities primarily relate to nuclear generation plant decommissioning, land reclamation related to lignite mining, and remediation or closure of coal ash basins. In estimating the ARO liability, we are required to make significant estimates and assumptions.

For the estimates and assumptions of the nuclear generation plant decommissioning, we use unit-by-unit decommissioning cost studies to provide a marketplace assessment of the expected costs (in current year dollars) and timing of decommissioning activities, which are validated by comparison to current decommissioning projects within the industry and other estimates. Decommissioning cost studies are updated for each of our nuclear units at least every five years unless circumstances warrant a more frequent update. In estimating the liability for December 31, 2023, we have included an assumption that Vistra receives a license extension of 20 years from the NRC to continue to operate Comanche Peak Units 1 and 2 through 2050 and 2053, respectively. The costs to ultimately decommission the facility are recoverable through the regulatory rate making process as part of Oncor's delivery fees and therefore changes in estimates of the ARO do not impact Vistra's earnings.

The estimates and assumptions required for the mining land reclamation related to lignite mining, such as costs to fill in mining pits and interpretation of the mining permit closure requirements, are complex and require a significant amount of judgment. To develop the estimate of costs to fill in mining pits, we utilize a complex proprietary model to estimate the volume of the pit. A significant portion of the estimate is associated with the Asset Closure segment, thus related to closed facilities with changes in the estimate recorded to our consolidated statements of operations.

These obligations are adjusted on a regular basis to reflect the passage of time and to incorporate revisions to the following significant estimates and assumptions:

- estimation of dates for retirement, which can be dependent on environmental and other legislation;
- amounts and timing of future cash expenditures associated with retirement, settlement or remediation activities;
- discount rates;
- cost escalation factors;
- market risk premium;
- inflation rates; and
- if applicable, past experience with government regulators regarding similar obligations.

For the next five years, Vistra is projected to spend approximately $516 million (on a nominal basis) to achieve its mining reclamation and other coal ash remediation objectives. During the years ended December 31, 2023, 2022 and 2021, we transferred zero, $61 million and zero, respectively, in ARO obligations to third parties for remediation. Any remaining unpaid third-party obligation was reclassified to other current liabilities and other noncurrent liabilities and deferred credits in our consolidated balance sheets.

See Note 22 to the Financial Statements for additional discussion of ARO obligations and adjustments made to the ARO obligation estimates during the years ended December 31, 2023, 2022 and 2021.

Impairment of Goodwill and Other Long-Lived Assets

We evaluate long-lived assets (including intangible assets with finite lives) for impairment, in accordance with accounting standards related to impairment or disposal of long-lived assets, whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. For our generation assets, possible indications include an expectation of continuing long-term declines in natural gas prices and/or Market Heat Rates or an expectation that "more likely than not" a generation asset will be sold or otherwise disposed of significantly before the end of its estimated useful life. The determination of the existence of these and other indications of impairment involves judgments that are subjective in nature and may require the use of estimates in forecasting future results and cash flows related to an asset or group of assets. Further, the unique nature of our property, plant and equipment, which includes a fleet of generation assets with a diverse fuel mix and individual generation units that have varying production or output rates, requires the use of significant judgments in determining the existence of impairment indications and the grouping of assets for impairment testing. See Note 22 to the Financial Statements for discussion of impairments of long-lived assets recorded in the years ended December 31, 2022, 2021 and 2020.

Recoverability of long-lived assets is determined by a comparison of the carrying amount of the long-lived asset group to the net cash flows expected to be generated by the asset group, through considering specific assumptions for forward natural gas and electricity prices, forward capacity prices, the effects of enacted environmental rules, generation plant performance, forecasted capital expenditures, forecasted fuel prices and forecasted operating costs. The carrying value of such asset groups is determined to be unrecoverable if the projected undiscounted cash flows are less than the carrying value.

If an asset group carrying value is determined to be unrecoverable, fair value will be calculated based on a market participant view and a loss will be recorded for the amount the carrying value exceeds the fair value. Fair value is determined primarily by discounted cash flows (income approach) and supported by available market valuations, if applicable. The income approach involves estimates of future performance that reflect assumptions regarding, among other things, forward natural gas and electricity prices, forward capacity prices, Market Heat Rates, the effects of enacted environmental rules, generation plant performance, forecasted capital expenditures and forecasted fuel prices. Another key assumption in the income approach is the discount rate applied to the forecasted cash flows. Any significant change to one or more of these factors can have a material impact on the fair value measurement of our long-lived assets. Additional material impairments related to our generation facilities may occur in the future if forward wholesale electricity prices decline in the markets in which we operate in or if additional environmental regulations increase the cost of producing electricity at our generation facilities.

Goodwill and intangible assets with indefinite useful lives, such as the intangible asset related to the trade names of TXU Energy™, Ambit Energy, 4Change Energy™, Homefield, Dynegy Energy Services, TriEagle Energy, Public Power and U.S. Gas & Electric, respectively, are required to be evaluated for impairment at least annually (we have selected October 1 as our annual impairment test date) or whenever events or changes in circumstances indicate an impairment may exist, such as the indicators used to evaluate impairments to long-lived assets discussed above or declines in values of comparable public companies in our industry.

As of December 31, 2023, our goodwill balances totaled $2.461 billion and $122 million for our Retail reporting unit and Texas Generation reporting unit, respectively. Under this goodwill impairment analysis, if at the assessment date, a reporting unit's carrying value exceeds its estimated fair value, the excess carrying value is written off as an impairment charge. Accounting standards allow a company to qualitatively assess if the carrying value of a reporting unit with goodwill is more likely than not less than the fair value of that reporting unit. If the entity determines the carrying value, including goodwill, is not more likely greater than the fair value, no further testing of goodwill for impairment is required. On the most recent goodwill testing date, we performed a qualitative assessment and determined that it was more likely than not that the fair value of our Retail and Texas Generation reporting units exceeded their carrying value at October 1, 2023. Significant qualitative factors evaluated included reporting unit financial performance and market multiples, general macroeconomic, industry, and market conditions, cost factors, customer attrition, interest rates and changes in reporting unit book value.

As of December 31, 2023, intangible assets with indefinite useful lives related to our retail trade names totaled $1.341 billion. Under this impairment analysis, if at the assessment date, a retail trade name's carrying value exceeds its estimated fair value, the excess carrying value is written off as an impairment charge.

Accounting standards allow a company to qualitatively assess if the carrying value of our retail trade name intangible assets is more likely than not less than the fair value. On the most recent testing date, we performed a qualitative assessment and determined that it was more likely than not that the fair value of our retail trade names exceeded their carrying value at October 1, 2023. Significant qualitative factors evaluated included trade name financial performance, general macroeconomic, industry, and market conditions, customer attrition and interest rates.

Results of Operations

Net income (loss) attributable to Vistra common stock increased $2.6 billion to income of $1.5 billion for the year ended December 31, 2023 from a loss of $1.2 billion for the year ended December 31, 2022. For additional information see the following discussion of our results of operations.

EBITDA and Adjusted EBITDA

In analyzing and planning for our business, we supplement our use of GAAP financial measures with non-GAAP financial measures, including EBITDA and Adjusted EBITDA as performance measures. These non-GAAP financial measures reflect an additional way of viewing aspects of our business that, when viewed (i) with our GAAP results and (ii) the accompanying reconciliations to corresponding GAAP financial measures may provide a more complete understanding of factors and trends affecting our business. Because EBITDA and Adjusted EBITDA are financial measures that management uses to allocate resources, determine our ability to fund capital expenditures, assess performance against our peers, and evaluate overall financial performance, we believe they provide useful information for investors.

These non-GAAP financial measures should not be relied upon to the exclusion of GAAP financial measures and are, by definition, an incomplete understanding of Vistra and must be considered in conjunction with GAAP measures. In addition, non-GAAP financial measures are not standardized; therefore, it may not be possible to compare these financial measures with other companies' non-GAAP financial measures having the same or similar names. We strongly encourage investors to review our consolidated financial statements and publicly filed reports in their entirety and not rely on any single financial measure.

When EBITDA or Adjusted EBITDA is discussed in reference to performance on a consolidated basis, the most directly comparable GAAP financial measure to EBITDA and Adjusted EBITDA is Net income (loss).

Vistra Consolidated Financial Results — Year Ended December 31, 2023 Compared to Year Ended December 31, 2022

The following table presents net income (loss), EBITDA and adjusted EBITDA for the year ended December 31, 2023:

	Year Ended December 31, 2023					
	Retail	Texas	East	West	Sunset	Asset Closure
Operating revenues	$ 10,572	$ 3,823	$ 4,215	$ 914	$ 1,831	$ —
Fuel, purchased power costs and delivery fees	(9,046)	(1,951)	(2,031)	(328)	(776)	(3)
Operating costs	(123)	(894)	(297)	(58)	(254)	(74)
Depreciation and amortization	(102)	(544)	(647)	(79)	(62)	—
Selling, general and administrative expenses	(858)	(134)	(82)	(24)	(51)	(34)
Impairment of long-lived assets	—	—	—	—	(49)	—
Operating income (loss)	443	300	1,158	425	639	(111)
Other income	1	35	3	21	1	110
Other deductions	—	(2)	—	—	(5)	—
Interest expense and related charges	(20)	21	—	8	(2)	(5)
Impacts of Tax Receivable Agreement	—	—	—	—	—	—
Income (loss) before income taxes	424	354	1,161	454	633	(6)
Income tax expense	—	—	(1)	—	—	—
Net income (loss)	**$ 424**	**$ 354**	**$ 1,160**	**$ 454**	**$ 633**	**$ (6)**

	Year Ended December 31, 2023					
	Retail	Texas	East	West	Sunset	Asset Closure
Income tax expense	—	—	1	—	—	—
Interest expense and related charges (a)	20	(21)	—	(8)	2	5
Depreciation and amortization (b)	102	635	647	79	62	—
EBITDA before Adjustments	546	968	1,808	525	697	(1)
Unrealized net (gain) loss resulting from commodity hedging transactions	586	799	(1,117)	(267)	(455)	(36)
Impacts of Tax Receivable Agreement (c)	—	—	—	—	—	—
Non-cash compensation expenses	—	—	—	—	—	—
Transition and merger expenses	—	1	1	—	1	—
Impairment of long-lived assets	—	—	—	—	49	—
PJM capacity performance default impacts (d)	—	—	3	—	6	—
Winter Storm Uri impacts (e)	(52)	4	—	—	—	—
Other, net	25	(2)	12	5	60	(2)
Adjusted EBITDA	**$ 1,105**	**$ 1,770**	**$ 707**	**$ 263**	**$ 358**	**$ (39)**

(a) Includes $36 million of unrealized mark-to-market net losses on interest rate swaps.

(b) Includes nuclear fuel amortization of $91 million in the Texas segment.
(c) Includes $29 million gain recognized on the repurchase of TRA Rights in December 2023 (see Note 8 to the Financial Statements).
(d) Represents estimate of anticipated market participant defaults or settlements on initial PJM capacity performance penalties due to extreme magnitude of penalties associated with Winter Storm Elliott.
(e) Includes the application of bill credits. The Company incentivized certain large commercial and industrial customers to curtail their usage during Winter Storm Uri by providing bill credits for use in future periods. The Company believes the inclusion of the bill credits as a reduction to Adjusted EBITDA in the years in which such bill credits are applied more accurately reflects its operating performance. We estimate remaining bill credit amounts to be applied in future periods for 2024 (approximately $11 million) and 2025 (approximately $26 million).

The following table presents net income (loss), EBITDA and adjusted EBITDA for the year ended December 31, 2022:

	Year Ended December 31, 2022					
	Retail	Texas	East	West	Sunset	Asset Closure
Operating revenues	$ 9,455	$ 3,733	$ 3,706	$ 336	$ 868	$ 384
Fuel, purchased power costs and delivery fees	(7,169)	(2,968)	(3,546)	(481)	(670)	(322)
Operating costs	(143)	(808)	(255)	(42)	(251)	(145)
Depreciation and amortization	(145)	(537)	(706)	(42)	(66)	(31)
Selling, general and administrative expenses	(826)	(131)	(66)	(21)	(35)	(44)
Impairment of long-lived assets	—	—	—	—	(74)	—
Operating income (loss)	1,172	(711)	(867)	(250)	(228)	(158)

	Year Ended December 31, 2022					
	Retail	Texas	East	West	Sunset	Asset Closure
Other income	2	78	2	6	—	16
Other deductions	(2)	(2)	—	—	1	(2)
Interest expense and related charges	(14)	20	(3)	6	(3)	(3)
Impacts of Tax Receivable Agreement	—	—	—	—	—	—
Income (loss) before income taxes	1,158	(615)	(868)	(238)	(230)	(147)
Income tax benefit	—	—	—	—	—	—
Net income (loss)	**$ 1,158**	**$ (615)**	**$ (868)**	**$ (238)**	**$ (230)**	**$ (147)**
Income tax benefit	—	—	—	—	—	—
Interest expense and related charges (a)	14	(20)	3	(6)	3	3
Depreciation and amortization (b)	145	623	706	42	66	31
EBITDA before Adjustments	1,317	(12)	(159)	(202)	(161)	(113)
Unrealized net (gain) loss resulting from commodity hedging transactions	(291)	1,610	759	351	100	(19)
Generation plant retirement expenses	—	—	—	—	7	(3)
Fresh start/ purchase accounting impacts	—	(2)	(1)	—	9	—
Impacts of Tax Receivable Agreement	—	—	—	—	—	—
Non-cash compensation expenses	—	—	—	—	—	—

(a) Includes $250 million of unrealized mark-to-market net gains on interest rate swaps.
(b) Includes nuclear fuel amortization of $86 million in the Texas segment.
(c) Adjusted EBITDA impacts of Winter Storm Uri reflects $183 million related to a reduction in the allocation of ERCOT default uplift charges which were expected to be paid over several decades under protocols existing at the time of the storm and $144 million related to the application of bill credits to large commercial and industrial customers that curtailed their usage during Winter Storm Uri. The adjustment for ERCOT default uplift charges relates to (i) ERCOT receiving payments that reduced the market wide default balance and (ii) the fourth quarter 2022 derecognition of the remaining default balance in connection with a settlement between Brazos and ERCOT.

Operating income increased $3.838 billion to $2.661 billion in the year ended December 31, 2023 compared to the year ended December 31, 2022. Results for the year ended December 31, 2023 were favorably impacted by $490 million in pre-tax unrealized mark-to-market gains on derivative positions due to power and natural gas forward market curves moving down in the year ended December 31, 2023 compared to $2.510 billion in pre-tax unrealized mark-to-market losses on commodity derivative positions due to power and natural gas forward market curves moving up materially in the year ended December 31, 2022. See further information on our derivative results in *Energy-Related Commodity Contracts and Mark-to-Market Activities* below.

Operating results for the year ended December 31, 2023, compared to the year ended December 31, 2022 were favorably impacted by strong plant operating performance allowing us to realize the value created by our comprehensive hedging strategy, partially offset by lower than expected retail sales volumes due to unfavorable weather. The following table presents operational performance of our retail and generation segments.

	Year Ended December 31,						
	Retail		Texas		East		
	2023	2022	2023	2022	2023	2022	2023
Retail sales volumes (GWh):							
Retail electricity sales volumes:							
Sales volumes in ERCOT	70,275	65,207					
Sales volumes in Northeast/ Midwest	27,147	32,882					
Total retail electricity sales volumes	97,422	98,089					
Production volumes (GWh):							
Natural gas facilities			41,849	34,784	60,502	54,569	5,46
Lignite and coal facilities			23,899	25,211			
Nuclear facilities			18,893	19,688			
Solar facilities			781	822			
Capacity factors:							
CCGT facilities			55.1 %	48.8 %	62.2 %	57.2 %	61.0 %
Lignite and coal facilities			70.9 %	74.8 %			
Nuclear facilities			89.9 %	93.6 %			
Weather - percent of normal (a):							
Cooling degree days	115 %	111 %	112 %	109 %	90 %	107 %	79 %
Heating degree days	85 %	108 %	88 %	123 %	87 %	99 %	125 %

(a) Reflects cooling degree or heating degree days for the region based on Weather Services International (WSI) data.

	Year Ended December 31,			Year Ended December 31,	
	2023	2022		2023	2022
Market pricing			**Average Market On-Peak Power Prices ($MWh) (b):**		
Average ERCOT North power price ($/MWh)	$ 48.30	$ 62.17	PJM West Hub	$ 39.22	$ 83.59
			AEP Dayton Hub	$ 36.22	$ 79.51
Average NYMEX Henry Hub natural gas price ($/MMBtu)	$ 2.53	$ 6.39	NYISO Zone C	$ 30.38	$ 65.54
			Massachusetts Hub	$ 41.02	$ 92.17
Average natural gas price (a):			Indiana Hub	$ 38.92	$ 82.03
TetcoM3 ($/MMBtu)	$ 1.90	$ 6.81	Northern Illinois Hub	$ 32.67	$ 71.76
Algonquin Citygates ($/MMBtu)	$ 2.94	$ 9.16	CAISO NP15	$ 63.92	$ 93.12

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(a) Reflects the average of daily quoted prices for the periods presented and does not reflect costs incurred by us.
(b) Reflects the average of day-ahead quoted prices for the periods presented and does not necessarily reflect prices we realized.

For the year ended December 31, 2023, other income totaled $257 million driven by a gain of $89 million from the sale of property in Freestone County, Texas recorded in the Asset Closure Segment and $86 million in interest income due to holding a material cash balance anticipating the Energy Harbor transaction closing. For the year ended December 31, 2022, other income totaled $117 million driven by insurance proceeds of $70 million which primarily consists of business interruption claim proceeds recorded in the Texas segment. See Note 22 to the Financial Statements.

The increase in consolidated interest expense and related charges of $372 million for the year ended December 31, 2023, compared to the year ended December 31, 2022, is primarily due to (a) unrealized mark-to-market losses on interest rate swaps of $36 million in 2023 compared to unrealized mark-to-market gains on interest rate swaps of $250 million in 2022 due to less volatility in interest rates in the year ended December 31, 2023 compared to the year ended December 31, 2022, (b) an increase in interest paid/accrued of $63 million driven by higher effective interest rates in 2023 and (c) $21 million of commitment fees related to the Commitment Letter in the year ended December 31, 2023. See Note 22 to the Financial Statements.

The following table presents additional changes to net income (loss) and Adjusted EBITDA for the year ended December 31, 2023 compared to the year ended December 31, 2022.

	Year Ended December 31, 2023 Compared to 2022				
	Retail	Texas	East	West	Sunset
Favorable change in realized revenue net of fuel driven by effectiveness of comprehensive hedging	$ —	$ 483	$ 153	$ 113	$ 357
Higher margins driven by increase in customers and interyear timing of power supply costs	290	—	—	—	—
Winter Storm Uri bill credit runoff	92	—	—	—	—
Impacts of mild weather in 2023	(160)	—	—	—	—
Change in operating costs due primarily to change in generation volumes	—	(86)	(40)	(17)	1
Change in SG&A and other	(40)	(65)	(14)	15	(42)
Change in Adjusted EBITDA	**$ 182**	**$ 332**	**$ 99**	**$ 111**	**$ 316**
Favorable/(unfavorable) change in depreciation and amortization	43	(12)	59	(37)	4
Change in unrealized net gains (losses) on hedging activities	(877)	811	1,876	618	555
Impairment of long-lived assets	—	—	—	—	25
PJM capacity performance default impacts	—	—	(3)	—	(6)
Winter Storm Uri impact (ERCOT default uplift)	(89)	(182)	—	—	—
Other (including interest expenses)	7	20	(3)	—	(31)
Change in Net income	**$ (734)**	**$ 969**	**$ 2,028**	**$ 692**	**$ 863**

To supplement the amounts and explanations noted above, primary drivers of results for the year ended December 31, 2023 compared to the year ended December 31, 2022 include:

- *Comprehensive hedging strategy*. See *Energy-Related Commodity Contracts and Mark-to-Market Activities* below.

- *Winter Storm Uri impacts*. 2022 GAAP and Adjusted EBITDA results continued to be materially impacted by Winter Storm Uri. In 2022, a $189 million default uplift liability to ERCOT was extinguished and resulted in net income during the year, but had no impact on Adjusted EBITDA in 2022 as the initial liability incurred in 2021 was excluded from Adjusted EBITDA.

- *SG&A expenses and other*. 2023 is unfavorable compared to 2022 driven primarily by higher incentive compensation in 2023 and insurance recoveries recorded in Texas in 2022.

Asset Closure Segment — Year Ended December 31, 2023 Compared to Year Ended December 31, 2022

	Year Ended December 31, 2023	Year Ended December 31, 2022	Favorable (Unfavorable) Change
Operating revenues	$ —	$ 384	$ (384)
Fuel, purchased power costs and delivery fees	(3)	(322)	319
Operating costs	(74)	(145)	71
Depreciation and amortization	—	(31)	31
Selling, general and administrative expenses	(34)	(44)	10
Operating loss	(111)	(158)	47
Other income	110	16	94
Other deductions	—	(2)	2
Interest expense and related charges	(5)	(3)	(2)
Income (loss) before income taxes	(6)	(147)	141
Net loss	**$ (6)**	**$ (147)**	**$ 141**
Adjusted EBITDA	**$ (39)**	**$ (125)**	**$ 86**
Production volumes (GWh)	—	9,401	(9,401)

For the year ended December 31, 2022, results and volumes for the Asset Closure segment include those from Edwards generation plant that we retired on January 1, 2023 and include unrealized hedging gains related to coal and power derivatives of $19 million. Operating costs for the years ended December 31, 2023 and 2022 also include ongoing costs associated with the decommissioning and reclamation of retired plants and mines. GAAP and Adjusted EBITDA results for 2023 are favorable to 2022 primarily due to the $89 million gain on sale of land in Freestone County, Texas.

Energy-Related Commodity Contracts and Mark-to-Market Activities

As forward power prices materially increased in 2022, our generation segments (Texas, East, West and Sunset) aggressively sold forward power for 2023 and future years. While settled power prices in 2023 are lower than 2022, the strategic hedging allowed us to lock in margins for 2023 which resulted in realized revenue net of fuel above what we were able to recognize in 2022 (were mostly hedged going into 2022 so did not recognize the full benefit of settled prices). The forward power sales are also the drivers of the changes in unrealized gains/losses on hedging activities. As power prices increase/decrease in comparison to what our generation segments have sold forward, the generation segments recognize unrealized losses/gains. The retail segment procures power from the generation segments to serve future load obligations and thus changes in forward power prices have an inverse effect on unrealized mark to market for the retail segment as compared to the generation segments. This is evident in 2022 as material increase in forward power prices drove material unrealized losses in our generation segment, partially offset by unrealized gains in our retail segment. In 2023, forward power prices decreased slightly which resulted in unrealized gains in our generation segments which is partially offset by unrealized losses in our retail segment.

The table below summarizes the changes in commodity contract assets and liabilities for the years ended December 31, 2023 and 2022. The net change in these assets and liabilities, excluding "other activity" as described below, reflects $490 million in unrealized net gains and $2.51 billion in unrealized net losses for the years ended December 31, 2023 and 2022, respectively, arising from mark-to-market accounting for positions in the commodity contract portfolio.

	Year Ended December 31,	
	2023	2022
Commodity contract net liability at beginning of period	$ (3,148)	$ (866)
Settlements/termination of positions (a)	1,643	1,218
Changes in fair value of positions in the portfolio (b)	(1,153)	(3,728)
Other activity (c)	(82)	228
Commodity contract net liability at end of period	$ (2,740)	$ (3,148)

(a) Represents reversals of previously recognized unrealized gains and losses upon settlement/termination (offsets realized gains/(losses) recognized in the settlement period). Excludes changes in fair value in the month the position settled as well as amounts related to positions entered into, and settled, in the same month.
(b) Represents unrealized net gains/(losses) recognized, reflecting the effect of changes in fair value. Excludes changes in fair value in the month the position settled as well as amounts related to positions entered into, and settled, in the same month.
(c) Represents changes in fair value of positions due to receipt or payment of cash not reflected in unrealized gains or losses. Amounts are generally related to premiums related to options purchased or sold as well as certain margin deposits classified as settlement for certain transactions executed on the CME.

The following maturity table presents the net commodity contract liability arising from recognition of fair values at December 31, 2023, scheduled by the source of fair value and contractual settlement dates of the underlying positions.

	Maturity dates of unrealized commodity contract net liability at December 31, 2023				
Source of Fair Value	Less than 1 year	1-3 years	4-5 years	Excess of 5 years	Total
Prices actively quoted	$ (725)	$ (207)	$ 3	$ —	$ (929)
Prices provided by other external sources	(358)	(409)	—	—	(767)
Prices based on models	(355)	(454)	(138)	(97)	(1,044)
Total	$ (1,438)	$ (1,070)	$ (135)	$ (97)	$ (2,740)

We have engaged in natural gas hedging activities to mitigate the risk of higher or lower wholesale electricity prices that have corresponded to increases or declines in natural gas prices. When natural gas prices are elevated or depressed, we continue to seek opportunities to manage our wholesale power price exposure through hedging activities, including forward wholesale and retail electricity sales.

Estimated hedging levels for generation volumes in our Texas, East, West and Sunset segments as of December 31, 2023 were as follows:

	2024	2025
Nuclear/Renewable/Coal Generation:		
Texas	96 %	93 %
Sunset	96 %	58 %
Natural Gas Generation:		
Texas	89 %	80 %
East	99 %	80 %
West	100 %	81 %

Financial Condition

Cash Flows

Operating Cash Flows

Year Ended December 31, 2023 Compared to Year Ended December 31, 2022 — Cash provided by operating activities totaled $5.453 billion and $485 million in the years ended December 31, 2023 and 2022, respectively. The favorable change of $4.968 billion was primarily driven by (a) a decrease in net margin deposits (return of cash) of $1.899 billion in the year ended December 31, 2023 as compared to an increase in net margin deposits of $1.874 billion in the year ended December 31, 2022 related to commodity contracts which support our comprehensive hedging strategy, including the impacts of cash margin deposits returned and replaced with amounts posted under an affiliate financing agreement (see Note 11 to the Financial Statements) and (b) an increase in cash from operating income exclusive of net margin deposits, partially offset by $544 million of securitization proceeds from ERCOT in the year ended December 31, 2022 (see Note 1 to the Financial Statements).

Depreciation and amortization — Depreciation and amortization expense reported as a reconciling adjustment in the consolidated statements of cash flows exceeds the amount reported in the consolidated statements of operations by $454 million, $451 million and $297 million for the years ended December 31, 2023, 2022 and 2021, respectively. The difference represents amortization of nuclear fuel, which is reported as fuel costs in the consolidated statements of operations consistent with industry practice, and amortization of intangible net assets and liabilities that are reported in various other consolidated statements of operations line items including operating revenues and fuel and purchased power costs and delivery fees (see Note 6 to the Financial Statements).

Investing Cash Flows

Year Ended December 31, 2023 Compared to Year Ended December 31, 2022 — Cash used in investing activities totaled $2.145 billion and $1.239 billion in the years ended December 31, 2023 and 2022, respectively. The increase of $906 million was driven by (a) $543 million in higher net purchases of environmental allowances and (b) a $375 million increase in capital expenditures due primarily to continued development of our solar and energy storage generation facilities (see Note 3 to the Financial Statements), partially offset by $37 million in higher proceeds from the sale of assets driven by our sale of property in Freestone County, Texas in the year ended December 31, 2023.

	Year Ended December 31,		
	2023	**2022**	**Increase (Decrease)**
Capital expenditures, including LTSA prepayments	$ (764)	$ (628)	(136)
Nuclear fuel purchases	(214)	(198)	(16)
Growth and development expenditures	(698)	(475)	(223)
Total capital expenditures	(1,676)	(1,301)	(375)
Net sales (purchases) of environmental allowances	(571)	(28)	(543)
Net sales of (investments in) nuclear decommissioning trust fund securities	(23)	(23)	0
Proceeds from sales of property, plant and equipment	115	78	37
Other investing activity	10	35	(25)
Cash used in investing activities	$ (2,145)	$ (1,239)	$ (906)

Financing Cash Flows

Year Ended December 31, 2023 Compared to Year Ended December 31, 2022 — Cash used in financing activities totaled $294 million and $80 million in the years ended December 31, 2023 and 2022, respectively. The $214 million increase in cash used was driven by (a) the net repayment of $1.075 billion in the year ended December 31, 2023 of short-term debt and accounts receivable financing amounts borrowed in the year ended December 31, 2022 driven by changes in collateral posting requirements and (b) $1.5 billion principal amount of senior secured notes issued in May 2022, partially offset by (1) $2.5 billion principal amount of senior secured and senior unsecured notes issued in September 2023 and December 2023, of which $750 million will be used to fund cash tender offers in January 2024, and (2) lower share repurchases in 2023.

	Year Ended December 31,		
	2023	2022	Increase (Decrease)
Share repurchases	$ (1,245)	$ (1,949)	$ 704
Issuances of senior notes	2,498	1,498	1,000
Other net long-term borrowings (repayments), including the forward capacity agreements	(33)	(251)	218
Net short-term borrowings (repayments)	(650)	650	(1,300)
Net borrowings (repayments) under the accounts receivable financing facilities	(425)	425	(850)
Dividends paid to common stockholders	(313)	(302)	(11)
Dividends paid to preferred stockholders	(150)	(151)	1
Other financing activity	24	—	24
Cash used in financing activities	$ (294)	$ (80)	$ (214)

Collateral Financing Agreement With Affiliate

On June 15, 2023, Vistra Operations entered into a facility agreement (Facility Agreement) with a Delaware trust formed by the Company that sold 450,000 pre-capitalized trust securities (P-Caps) redeemable May 17, 2028 for an initial purchase price of $450 million. The Trust is not consolidated by Vistra. The Trust invested the proceeds from the sale of the P-Caps in a portfolio of either (a) U.S. Treasury securities (Treasuries) or (b) Treasuries and/or principal and interest strips of Treasuries (Treasury Strips, and together with the Treasuries and cash denominated in U.S. dollars, the Eligible Assets). At the direction of Vistra Operations, the Eligible Assets held by the Trust will be (i) delivered to one or more designated subsidiaries of Vistra Operations in order to allow such subsidiaries to use the Eligible Assets to meet certain posting obligations with counterparties, and/or (ii) pledged as collateral support for a letter of credit program.

Under the Facility Agreement, Vistra Operations will have the right (Issuance Right), from time to time, to require the Trust to purchase from Vistra Operations up to $450 million aggregate principal amount of Vistra Operations' 7.233% senior secured notes due 2028 (7.233% Senior Secured Notes) in exchange for the delivery of all or a portion of the Treasuries and Treasury Strips corresponding to the portion of the issuance right exercised at such time.

As of December 31, 2023, all of the Eligible Assets were being utilized to meet a portion of our current and future collateral posting obligations.

The Trust will terminate at any time prior to May 17, 2028 and distribute the 7.233% Senior Secured Notes to the holders of the P-Caps if its sole assets consist of 7.233% Senior Secured Notes that Vistra Operations is no longer entitled to repurchase.

See Note 11 for additional details of the collateral financing agreement with affiliate.

Debt Activity

We remain committed to a strong balance sheet and have continued to state our objective to reduce our consolidated net leverage. We also intend to maintain adequate liquidity and pursue opportunities to refinance our long-term debt to extend maturities.

In May 2024 and July 2024, after taking into account the Senior Secured Notes Tender Offer settled in January 2024, $342 million of 4.875% Senior Secured Notes and $1.155 billion of 3.550% Senior Secured Notes, respectively, will reach maturity. We plan to fund these upcoming principal payments using a combination of cash on hand and new debt issuances. Increases in interest rates will likely result in increased borrowing costs.

See Note 10 to the Financial Statements for details of the Receivables Facility and Repurchase Facility and Note 12 to the Financial Statements for details of the Vistra Operations Credit Facilities, the Commodity-Linked Facility and other long-term debt.

Available Liquidity

The following table summarizes changes in available liquidity for the year ended December 31, 2023:

	December 31, 2023	December 31, 2022	Change
Cash and cash equivalents (a)	$ 3,485	$ 455	$ 3,030
Vistra Operations Credit Facilities — Revolving Credit Facility (b)	1,213	1,236	(23)
Vistra Operations — Commodity-Linked Facility (c)	1,101	808	293
Total available liquidity (d)(e)	$ 5,799	$ 2,499	$ 3,300

(a) See the Consolidated Statements of Cash Flows in the Financial Statements and *Cash Flows* above for details of the increase in cash and cash equivalents for the year ended December 31, 2023. The increase includes proceeds from the issuance of $1.75 billion and $750 million principal amount of Vistra Operations senior secured and senior unsecured notes in September 2023 and December 2023, respectively. Proceeds from the September 2023 issuance are expected to be used, together with cash on hand, to fund the Transactions. Proceeds from the December 2023 issuance were used to settle the Senior Secured Notes Tender Offers in January 2024.
(b) The decrease in availability for the year ended December 31, 2023 was driven by a $73 million increase in letters of credit outstanding under the facility and the maturity of $200 million of commitments under the Non-Extended Revolving Credit Facility, partially offset by $250 million in net repayments of borrowings under the facility.
(c) As of December 31, 2023 and 2022, the borrowing bases are less than the facility limits of $1.575 billion and $1.35 billion, respectively. As of December 31, 2023, available capacity reflects the borrowing base of $1.101 billion and no cash borrowings. As of December 31, 2022, available capacity reflects the borrowing base of $1.208 billion less $400 million in cash borrowings.
(d) Excludes amounts available to be borrowed under the Receivables Facility and the Repurchase Facility, respectively. See Note 10 to the Financial Statements for detail on our accounts receivable financing.
(e) Excludes any additional letters of credit that may be issued under the Secured LOC Facilities. See Note 12 to the Financial Statements for detail on our Secured LOC Facilities.

We expect to use cash on hand and borrowings under the Receivables Facility and Repurchase Facility and other liquidity facilities to fund the approximately $3.1 billion cash necessary to close the Energy Harbor acquisition. In addition, we believe that we will have access to sufficient liquidity to fund our other anticipated cash requirements through at least the next 12 months. Our operational cash flows tend to be seasonal and weighted toward the second half of the year.

Interest payments on long-term debt are expected to total approximately $744 million in 2024, $1.293 billion in 2025-2026, $955 million in 2027-2028 and $1.052 billion thereafter. See Note 12 to the Financial Statements for details of our long-term debt maturities.

Our obligations under commodity purchase and services agreements, including capacity payments, nuclear fuel and natural gas take-or-pay contracts, coal contracts, business services and nuclear-related outsourcing and other purchase commitments, are expected to total approximately $2.615 billion in 2024, $2.192 billion in 2025-2026, $982 million in 2027-2028 and $437 million thereafter. See Note 13 to the Financial Statements for maturities of lease liabilities and Note 14 to the Financial Statements for commitments related to long-term service and maintenance contracts.

Capital Expenditures

Estimated 2024 capital expenditures and nuclear fuel purchases as of December 31, 2023 total approximately $1.695 billion and include:

- $745 million for solar and energy storage development;
- $727 million for investments in generation and mining facilities;
- $149 million for nuclear fuel purchases; and
- $74 million for other growth expenditures.

Liquidity Effects of Commodity Hedging and Trading Activities

We have entered into commodity hedging and trading transactions that require us to post collateral if the forward price of the underlying commodity moves such that the hedging or trading instrument we hold has declined in value. We use cash, letters of credit, Eligible Assets (see Note 11 to the Financial Statements) and other forms of credit support to satisfy such collateral posting obligations. See Note 12 to the Financial Statements for discussion of the Vistra Operations Credit Facilities and the Commodity-Linked Facility.

Exchange cleared transactions typically require initial margin (*i.e.*, the upfront cash and/or letter of credit posted to take into account the size and maturity of the positions and credit quality) in addition to variation margin (*i.e.*, the daily cash margin posted to take into account changes in the value of the underlying commodity). The amount of initial margin required is generally defined by exchange rules. Clearing agents, however, typically have the right to request additional initial margin based on various factors, including market depth, volatility and credit quality, which may be in the form of cash, letters of credit, a guaranty or other forms as negotiated with the clearing agent. Cash collateral received from counterparties is either used for working capital and other business purposes, including reducing borrowings under credit facilities, or is required to be deposited in a separate account and restricted from being used for working capital and other corporate purposes. With respect to over-the-counter transactions, counterparties generally have the right to substitute letters of credit for such cash collateral. In such event, the cash collateral previously posted would be returned to such counterparties, which would reduce liquidity in the event the cash was not restricted.

As of December 31, 2023, we received or posted cash, letters of credit and Eligible Assets for commodity hedging and trading activities as follows:

- $1.244 billion in cash and Eligible Assets has been posted with counterparties as compared to $3.137 billion posted as of December 31, 2022;
- $45 million in cash has been received from counterparties as compared to $39 million received as of December 31, 2022;
- $2.408 billion in letters of credit have been posted with counterparties as compared to $2.314 billion posted as of December 31, 2022; and
- $143 million in letters of credit have been received from counterparties as compared to $74 million received as of December 31, 2022.

See *Collateral Support Obligations* below for information related to collateral posted in accordance with the PUCT and ISO/RTO rules.

Income Tax Payments

In the next 12 months, we do not expect to make federal income tax payments due to Vistra's NOL carryforwards. We expect to make approximately $35 million in state income tax payments offset by $10 million in state tax refunds.

For the year ended December 31, 2023, there were no federal income tax payments, $44 million in state income tax payments, $13 million in state income tax refunds and $9 million in TRA payments.

Capitalization

Our capitalization ratios consisted of 70% and 71% long-term debt (less amounts due currently) and 30% and 29% stockholders' equity at December 31, 2023 and 2022, respectively. Total long-term debt (including amounts due currently) to capitalization was 73% and 71% at December 31, 2023 and 2022, respectively.

Financial Covenants

The Vistra Operations Credit Agreement and the Vistra Operations Commodity-Linked Credit Agreement each includes a covenant, solely with respect to the Revolving Credit Facility and the Commodity-Linked Facility and solely during a compliance period (which, in general, is applicable when the aggregate revolving borrowings and issued revolving letters of credit exceed 30% of the revolving commitments, provided that solely with respect to the Revolving Credit Facility only such amounts in excess of $300 million are taken into account for purposes of determining whether a compliance period is in effect), that requires the consolidated first-lien net leverage ratio not to exceed 4.25 to 1.00 (or, during a collateral suspension period, the consolidated total net leverage ratio not to exceed 5.50 to 1.00). In addition, each of the Secured LOC Facilities includes a covenant that requires the consolidated first-lien net leverage ratio not to exceed 4.25 to 1.00 (or, for certain facilities that include a collateral suspension mechanism, during a collateral suspension period, the consolidated total net leverage ratio not to exceed 5.50 to 1.00). As of December 31, 2023, we were in compliance with the Vistra Operations Credit Agreement, Vistra Operations Commodity-Linked Credit Agreement and Secured LOC Facilities financial covenants.

See Note 12 to the Financial Statements for discussion of other covenants related to the Vistra Operations Credit Facilities.

Collateral Support Obligations

The RCT has rules in place to assure that parties can meet their mining reclamation obligations. In September 2016, the RCT agreed to a collateral bond of up to $975 million to support Luminant's reclamation obligations. The collateral bond is effectively a first lien on all of Vistra Operations' assets (which ranks pari passu with the Vistra Operations Credit Facilities) that contractually enables the RCT to be paid (up to $975 million) before the other first-lien lenders in the event of a liquidation of our assets. Collateral support relates to land mined or being mined and not yet reclaimed as well as land for which permits have been obtained but mining activities have not yet begun and land already reclaimed but not released from regulatory obligations by the RCT, and includes cost contingency amounts.

The PUCT has rules in place to assure adequate creditworthiness of each REP, including the ability to return customer deposits, if necessary. Under these rules, at December 31, 2023, Vistra has posted letters of credit in the amount of $91 million with the PUCT, which is subject to adjustments.

The ISOs/RTOs we operate in have rules in place to assure adequate creditworthiness of parties that participate in the markets operated by those ISOs/RTOs. Under these rules, Vistra has posted collateral support totaling $554 million in the form of letters of credit, $30 million in the form of a surety bond and $3 million of cash at December 31, 2023 (which is subject to daily adjustments based on settlement activity with the ISOs/RTOs).

Material Cross Default/Acceleration Provisions

Certain of our contractual arrangements contain provisions that could result in an event of default if there were a failure under financing arrangements to meet payment terms or to observe covenants that could result in an acceleration of payments due. Such provisions are referred to as "cross default" or "cross acceleration" provisions.

A default by Vistra Operations or any of its restricted subsidiaries in respect of certain specified indebtedness in an aggregate amount in excess of the greater of $300 million and 17.5% of Consolidated EBITDA may result in a cross default under the Vistra Operations Credit Facilities and the Commodity-Linked Facility. Such a default would allow the lenders under each such facility to accelerate the maturity of outstanding balances under such facilities, which totaled approximately $2.5 billion and zero, respectively, as of December 31, 2023.

Each of Vistra Operations' (or its subsidiaries') commodity hedging agreements and interest rate swap agreements that are secured with a lien on its assets on a pari passu basis with the Vistra Operations Credit Facilities lenders contains a cross-default provision. An event of a default by Vistra Operations or any of its subsidiaries relating to indebtedness equal to or above a threshold defined in the applicable agreement that results in the acceleration of such debt, would give such counterparty under these hedging agreements the right to terminate its hedge or interest rate swap agreement with Vistra Operations (or its applicable subsidiary) and require all outstanding obligations under such agreement to be settled.

Under the Vistra Operations Senior Unsecured Indentures, the Vistra Operations Senior Secured Indenture and the Indenture governing the 7.233% Senior Secured Notes, a default under any document evidencing indebtedness for borrowed money by Vistra Operations or any Guarantor Subsidiary for failure to pay principal when due at final maturity or that results in the acceleration of such indebtedness in an aggregate amount of $300 million or more may result in a cross default under the Vistra Operations Senior Unsecured Notes, the Senior Secured Notes, the 7.233% Senior Secured Notes, the Vistra Operations Credit Facilities, the Receivables Facility, the Commodity-Linked Facility and other current or future documents evidencing any indebtedness for borrowed money by the applicable borrower or issuer, as the case may be, and the applicable Guarantor Subsidiaries party thereto.

Additionally, we enter into energy-related physical and financial contracts, the master forms of which contain provisions whereby an event of default or acceleration of settlement would occur if we were to default under an obligation in respect of borrowings in excess of thresholds, which may vary by contract.

The Receivables Facility contains a cross-default provision. The cross-default provision applies, among other instances, if TXU Energy, Dynegy Energy Services, Ambit Texas, Value Based Brands, TriEagle Energy, each indirect subsidiaries of Vistra and originators under the Receivables Facility (Originators), and Vistra or any of their respective subsidiaries fails to make a payment of principal or interest on any indebtedness that is outstanding in a principal amount of at least $300 million, in the case of Vistra, and in a principal amount of at least $50 million, in the case of TXU Energy or any of the other Originators, after the expiration of any applicable grace period, or if other events occur or circumstances exist under such indebtedness which give rise to a right of the debtholder to accelerate such indebtedness, or if such indebtedness becomes due before its stated maturity. If this cross-default provision is triggered, a termination event under the Receivables Facility would occur and the Receivables Facility may be terminated.

The Repurchase Facility contains a cross-default provision. The cross-default provision applies, among other instances, if an event of default (or similar event) occurs under the Receivables Facility or the Vistra Operations Credit Facilities. If this cross-default provision is triggered, a termination event under the Repurchase Facility would occur and the Repurchase Facility may be terminated.

Under the Secured LOC Facilities, a default by Vistra Operations or any of its restricted subsidiaries in respect of certain specified indebtedness in an aggregate amount in excess of $300 million may result in a cross default under the Secured LOC Facilities. In addition, a default under any document evidencing indebtedness for borrowed money by Vistra Operations or any Guarantor Subsidiary for failure to pay principal when due at final maturity or that results in the acceleration of such indebtedness in an aggregate amount of $300 million or more, may result in a termination of the Secured LOC Facilities.

Under the Vistra Operations Senior Unsecured Indenture and the Vistra Operations Senior Secured Indenture governing the 7.750% Senior Unsecured Notes and 6.950% Senior Secured Notes, respectively, a default under any document evidencing indebtedness for borrowed money by Vistra Operations or any Guarantor Subsidiary for failure to pay principal when due at final maturity or that results in the acceleration of such indebtedness in an aggregate amount that exceeds the greater of 1.5% of total assets and $600 million may result in a cross default under the respective notes and other current or future documents evidencing any indebtedness for borrowed money by the applicable borrower or issuer, as the case may be, and the applicable Guarantor Subsidiaries party thereto.

Guarantees

See Note 14 to the Financial Statements for discussion of guarantees.

Commitments and Contingencies

See Note 14 to the Financial Statements for discussion of commitments and contingencies.

Changes in Accounting Standards

See Note 1 to the Financial Statements for discussion of changes in accounting standards.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risk is the risk that in the normal course of business we may experience a loss in value because of changes in market conditions that affect economic factors such as commodity prices, interest rates and counterparty credit. Our exposure to market risk is affected by several factors, including the size, duration and composition of our energy and financial portfolio, as well as the volatility and liquidity of markets. Instruments used to manage this exposure include interest rate swaps to hedge debt costs, as well as exchange-traded, over-the-counter contracts and other contractual arrangements to hedge commodity prices.

Risk Oversight

We manage the commodity price, counterparty credit and commodity-related operational risk related to the competitive energy business within limitations established by senior management and in accordance with overall risk management policies. Interest rate risk is managed centrally by our treasury function. Market risks are monitored by risk management groups that operate independently of the wholesale commercial operations, utilizing defined practices and analytical methodologies. These techniques measure the risk of change in value of the portfolio of contracts and the hypothetical effect on this value from changes in market conditions and include, but are not limited to, position reporting and review, Value at Risk (VaR) methodologies and stress test scenarios. Key risk control activities include, but are not limited to, transaction review and approval (including credit review), operational and market risk measurement, transaction authority oversight, validation of transaction capture, market price validation and reporting, and portfolio valuation and reporting, including mark-to-market, VaR and other risk measurement metrics.

Vistra has a risk management organization that enforces applicable risk limits, including the respective policies and procedures to ensure compliance with such limits, and evaluates the risks inherent in our businesses.

Commodity Price Risk

Our business is subject to the inherent risks of market fluctuations in the price of electricity, natural gas and other energy-related products it markets or purchases. We actively manage the portfolio of generation assets, fuel supply and retail sales load to mitigate the near-term impacts of these risks on results of operations. Similar to other participants in the market, we cannot fully manage the long-term value impact of structural declines or increases in natural gas and power prices.

In managing energy price risk, we enter into a variety of market transactions including, but not limited to, short- and long-term contracts for physical delivery, exchange-traded and over-the-counter financial contracts and bilateral contracts with customers. Activities include hedging, the structuring of long-term contractual arrangements and proprietary trading. We continuously monitor the valuation of identified risks and adjust positions based on current market conditions. We strive to use consistent assumptions regarding forward market price curves in evaluating and recording the effects of commodity price risk.

VaR Methodology

A VaR methodology is used to measure the amount of market risk that exists within the portfolio under a variety of market conditions. The resultant VaR produces an estimate of a portfolio's potential for loss given a specified confidence level and considers, among other things, market movements utilizing standard statistical techniques given historical and projected market prices and volatilities.

Parametric processes are used to calculate VaR and are considered by management to be the most effective way to estimate changes in a portfolio's value based on assumed market conditions for liquid markets. The use of this method requires a number of key assumptions, such as use of (i) an assumed confidence level, (ii) an assumed holding period (*i.e.*, the time necessary for management action, such as to liquidate positions) and (iii) historical estimates of volatility and correlation data. The table below details a VaR measure related to various portfolios of contracts.

VaR for Underlying Generation Assets and Energy-Related Contracts

This measurement estimates the potential loss in value, due to changes in market conditions, of all underlying generation assets and contracts, based on a 95% confidence level and an assumed holding period of 60 days. The forward period covered by this calculation includes the current and subsequent calendar year at the time of calculation.

	Year Ended December 31,	
	2023	2022
Month-end average VaR	$ 190	$ 489
Month-end high VaR	$ 423	$ 686
Month-end low VaR	$ 115	$ 283

The month-end high VaR risk measure in 2023 is currently lower than the prior year due to lower prices and higher hedge levels.

Price Sensitivities

The following sensitivity table provides approximate estimates of the potential impact of movements in power prices and spark spreads (the difference between the power revenue and fuel expense of natural gas-fired generation as calculated using an assumed Heat Rate of 7.2 MMBtu/MWh) on realized pre-tax earnings (in millions) taking into account the hedge positions noted above for the periods presented. The residual natural gas position is calculated based on two steps: first, calculating the difference between actual Heat Rates of our natural gas generation units and the assumed 7.2 Heat Rate used to calculate the sensitivity to spark spreads; and second, calculating the residual natural gas exposure that is not already included in the natural gas generation spark spread sensitivity shown in the table below. The estimates related to price sensitivity are based on our expected generation, related hedges and forward prices as of December 31, 2023.

	2024	2025
Texas:		
Nuclear/Renewable/Coal Generation: $2.50/MWh increase in power price	$ 5	$ 9
Nuclear/Renewable/Coal Generation: $2.50/MWh decrease in power price	$ (4)	$ (8)
Natural Gas Generation: $1.00/MWh increase in spark spread	$ 7	$ 10
Natural Gas Generation: $1.00/MWh decrease in spark spread	$ (6)	$ (9)
Residual Natural Gas Position: $0.25/MMBtu increase in natural gas price	$ (9)	$ 8
Residual Natural Gas Position: $0.25/MMBtu decrease in natural gas price	$ 3	$ (11)
East:		
Natural Gas Generation: $1.00/MWh increase in spark spread	$ 2	$ 11
Natural Gas Generation: $1.00/MWh decrease in spark spread	$ —	$ (10)
Residual Natural Gas Position: $0.25/MMBtu increase in natural gas price	$ (7)	$ (25)
Residual Natural Gas Position: $0.25/MMBtu decrease in natural gas price	$ 7	$ 25
West:		
Natural Gas Generation: $1.00/MWh increase in spark spread	$ —	$ 1
Natural Gas Generation: $1.00/MWh decrease in spark spread	$ —	$ (1)
Residual Natural Gas Position: $0.25/MMBtu increase in natural gas price	$ 1	$ 2
Residual Natural Gas Position: $0.25/MMBtu decrease in natural gas price	$ (1)	$ (2)
Sunset:		
Coal Generation: $2.50/MWh increase in power price	$ 3	$ 27
Coal Generation: $2.50/MWh decrease in power price	$ (2)	$ (27)

Interest Rate Risk

We manage our interest rate risk to limit the impact of interest rate changes on our results of operations and cash flows and to lower our overall borrowing costs. To achieve these objectives, a majority of our borrowings have fixed interest rates. The inflationary environment continues to drive elevated interest rates, resulting in increased expected refinancing or borrowing costs. See Item 7. *Management's Discussion and Analysis of Financial Condition, and Results of Operations – Significant Activities and Events, and Items Influencing Future Performance – Macroeconomic Conditions.*

The following table provides information concerning our financial instruments at December 31, 2023 and 2022 that are sensitive to changes in interest rates. Debt amounts consist of the Vistra Operations Credit Facilities. See Note 12 to the Financial Statements for further discussion of these financial instruments.

	Expected Maturity Date						
	2024	2025	2026	2027	2028	There-after	2[illegible] T[illegible] Car[illegible] Am[illegible]
Long-term debt, including current maturities (a):							
Variable rate debt amount	$ 25	$ 25	$ 25	$ 25	$ 25	$ 2,375	$ 2,[illegible]
Average interest rate (b)	7.36 %	7.36 %	7.36 %	7.36 %	7.36 %	7.36 %	7[illegible]
Debt swapped to fixed (c):							
Notional amount	$ —	$ —	$ 2,300	$ —	$ —	$ 1,625	$ 3,[illegible]
Average pay rate	5.42 %	5.41 %	5.37 %	5.28 %	5.28 %	5.28 %	
Average receive rate	7.36 %	7.36 %	7.36 %	7.36 %	7.36 %	7.36 %	

(a) Unamortized premiums, discounts and debt issuance costs are excluded from the table.
(b) The weighted average interest rate presented is based on the rates in effect at December 31, 2023.
(c) Interest rate swaps have maturity dates through December 2030, of which $1.625 billion become effective in July 2026. Maturities are presented net of $600 million and $700 million of debt swapped to variable maturing in 2024 and 2026, respectively, that is matched against the terms of the equivalent amounts of debt swapped to fixed that effectively fix the out-of-the-money position of such swaps (see Note 12 to the Financial Statements).

As of December 31, 2023, the potential reduction of annual pretax earnings over the next twelve months due to a one percentage-point (100 basis points) increase in floating interest rates on long-term debt totaled approximately $2 million taking into account the interest rate swaps discussed in Note 12 to Financial Statements.

Credit Risk

Credit risk relates to the risk of loss associated with nonperformance by counterparties. We minimize credit risk by evaluating potential counterparties, monitoring ongoing counterparty risk and assessing overall portfolio risk. This includes review of counterparty financial condition, current and potential credit exposures, credit rating and other quantitative and qualitative credit criteria. We also employ certain risk mitigation practices, including utilization of standardized master agreements that provide for netting and setoff rights, as well as credit enhancements such as margin deposits and customer deposits, letters of credit, parental guarantees and surety bonds. See Note 17 to the Financial Statements for further discussion of this exposure.

Credit Exposure

Our gross credit exposure (excluding collateral impacts) associated with retail and wholesale trade accounts receivable and net derivative assets arising from commodity contracts and hedging and trading activities totaled $1.976 billion at December 31, 2023.

As of December 31, 2023, Retail segment credit exposure totaled approximately $1.302 billion, including $1.241 billion of trade accounts receivable and $61 million related to derivatives. Cash deposits and letters of credit held as collateral for these receivables totaled $54 million, resulting in a net exposure of $1.248 billion. Allowances for uncollectible accounts receivable are established for the expected loss from nonpayment by these customers based on historical experience, market or operational conditions and changes in the financial condition of large business customers.

As of December 31, 2023, aggregate Texas, East, Sunset and Asset Closure segments credit exposure totaled $674 million including $545 million related to derivative assets and $129 million of trade accounts receivable, after taking into account master netting agreement provisions but excluding collateral impacts.

Including collateral posted to us by counterparties, our net Texas, East, Sunset and Asset Closure segments exposure was $551 million, as seen in the following table that presents the distribution of credit exposure by counterparty credit quality as of December 31, 2023. Credit collateral includes cash and letters of credit but excludes other credit enhancements such as guarantees or liens on assets.

	Exposure Before Credit Collateral	Credit Collateral	Net Exposure
Investment grade	$ 539	$ 26	$ 513
Below investment grade or no rating	135	97	38
Totals	$ 674	$ 123	$ 551

Significant (*i.e.*, 10% or greater) concentration of credit exposure exists with two counterparties, which represented an aggregate $293 million, or 53%, of our total net exposure as of December 31, 2023. We view exposure to these counterparties to be within an acceptable level of risk tolerance due to the counterparties' credit ratings, the counterparties' market role and deemed creditworthiness and the importance of our business relationship with the counterparty. An event of default by one or more counterparties could subsequently result in termination-related settlement payments that reduce available liquidity if amounts such as margin deposits are owed to the counterparties or delays in receipts of expected settlements owed to us.

Contracts classified as "normal" purchase or sale and non-derivative contractual commitments are not marked-to-market in the financial statements and are excluded from the detail above. Such contractual commitments may contain pricing that is favorable considering current market conditions and therefore represent economic risk if the counterparties do not perform.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of Vistra Corp.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Vistra Corp. and subsidiaries (the "Company") as of December 31, 2023 and 2022, the related consolidated statements of operations, consolidated statements of comprehensive income (loss), consolidated statements of cash flows, and consolidated statement of changes in equity, for each of the three years in the period ended December 31, 2023, and the related notes and the schedule listed in the Index at Item 15(b) (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2023, based on criteria established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2024, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Fair Value Measurements — Certain Complex Level 3 Derivative Assets and Liabilities — Refer to Notes 1 and 16 to the financial statements

Critical Audit Matter Description

The Company has derivative assets and liabilities whose fair values are based on complex proprietary models and/or unobservable inputs. These financial instruments can span a broad array of contract types, some of which include especially complex valuations due to unique contract terms and significant judgement by management in estimating prices or volumes, including (1) power purchases and sales that include power and heat rate positions; (2) physical power and natural gas options and swaptions; (3) forward purchase contracts for congestion revenue rights; and (4) retail sales contracts. Under accounting principles generally accepted in the United States of America, these financial instruments are generally classified as Level 3 derivative assets or liabilities.

Given management uses complex proprietary models and/or unobservable inputs to estimate the fair value of the aforementioned Level 3 derivative assets and liabilities, performing audit procedures to evaluate the reasonableness of the fair value of Level 3 derivative assets and liabilities required a high degree of auditor judgment and an increased extent of effort, including the need to involve our energy commodity fair value specialists who possess significant quantitative and modeling expertise.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the evaluation of the fair value of Level 3 derivative assets and liabilities included the following, among others:

- We tested the effectiveness of controls over derivative asset and liability valuations, including controls related to appropriate application of illiquid price curves and other significant unobservable valuation inputs.
- We obtained the Company's complete listing of derivative assets and liabilities and related fair values as of December 31, 2023, to obtain an understanding of the types of instruments outstanding.
- We assessed the consistency by which management has applied illiquid price curves and significant unobservable valuation inputs.
- With the assistance of our energy commodity fair value specialists, we developed independent estimates of the fair value of a sample of Level 3 derivative instruments and compared our estimates to the Company's estimates.

/s/ Deloitte & Touche LLP

Dallas, Texas
February 28, 2024

We have served as the Company's auditor since 2002.

VISTRA CORP.
CONSOLIDATED STATEMENTS OF OPERATIONS
(Millions of Dollars, Except Per Share Amounts)

	Year Ended December 31,		
	2023	2022	2021
Operating revenues (Note 5)	$ 14,779	$ 13,728	$ 12,077
Fuel, purchased power costs and delivery fees	(7,557)	(10,401)	(9,169)
Operating costs	(1,702)	(1,645)	(1,559)
Depreciation and amortization	(1,502)	(1,596)	(1,753)
Selling, general and administrative expenses	(1,308)	(1,189)	(1,040)
Impairment of long-lived and other assets	(49)	(74)	(71)
Operating income (loss)	2,661	(1,177)	(1,515)
Other income (Note 22)	257	117	140
Other deductions (Note 22)	(14)	(4)	(16)
Interest expense and related charges (Note 22)	(740)	(368)	(384)
Impacts of Tax Receivable Agreement (Note 8)	(164)	(128)	53
Net income (loss) before income taxes	2,000	(1,560)	(1,722)
Income tax (expense) benefit (Note 7)	(508)	350	458
Net income (loss)	1,492	(1,210)	(1,264)
Net (income) loss attributable to noncontrolling interest	1	(17)	(10)
Net income (loss) attributable to Vistra	1,493	(1,227)	(1,274)
Cumulative dividends attributable to preferred stock	(150)	(150)	(21)
Net income (loss) attributable to Vistra common stock	$ 1,343	$ (1,377)	$ (1,295)
Weighted average shares of common stock outstanding:			
Basic	369,771,359	422,447,074	482,214,544
Diluted	375,193,110	422,447,074	482,214,544
Net income (loss) per weighted average share of common stock outstanding:			
Basic	$ 3.63	$ (3.26)	$ (2.69)
Diluted	$ 3.58	$ (3.26)	$ (2.69)

See Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(Millions of Dollars)

	Year Ended December 31,		
	2023	2022	2021
Net income (loss)	$ 1,492	$ (1,210)	$ (1,264)
Other comprehensive income (loss), net of tax effects:			
Effects related to pension and other retirement benefit obligations (net of tax expense of $—, $7 and $9)	(1)	23	32
Total other comprehensive income (loss)	(1)	23	32
Comprehensive income (loss)	1,491	(1,187)	(1,232)
Comprehensive (income) loss attributable to noncontrolling interest	1	(17)	(10)
Comprehensive income (loss) attributable to Vistra	$ 1,492	$ (1,204)	$ (1,242)

See Notes to the Consolidated Financial Statements.

VISTRA CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions of Dollars)

	Year Ended December 31,		
	2023	2022	2021
Cash flows — operating activities:			
Net income (loss)	$ 1,492	$ (1,210)	$ (1,264)
Adjustments to reconcile net income (loss) to cash provided by (used in) operating activities:			
Depreciation and amortization	1,956	2,047	2,050
Deferred income tax expense (benefit), net	457	(359)	(475)
Gain on sale of land	(95)	(8)	(9)
Impairment of long-lived and other assets	49	74	71
Unrealized net (gain) loss from mark-to-market valuations of commodities	(490)	2,510	759
Unrealized net (gain) loss from mark-to-market valuations of interest rate swaps	36	(250)	(134)
Change in asset retirement obligation liability	27	13	(5)
Asset retirement obligation accretion expense	34	34	38
Impacts of Tax Receivable Agreement	164	128	(53)
Gain on TRA settlement	(29)	—	—
Bad debt expense	164	179	110
Stock-based compensation	77	63	47
Other, net	103	(71)	50
Changes in operating assets and liabilities:			
Accounts receivable — trade	214	(852)	(228)
Inventories	(174)	36	(100)
Accounts payable — trade	(350)	94	402
Commodity and other derivative contractual assets and liabilities	82	(228)	32
Margin deposits, net	1,899	(1,874)	(1,000)
Uplift securitization proceeds receivable from ERCOT	—	544	(544)
Accrued interest	46	16	13
Accrued taxes	5	(8)	(20)
Accrued employee incentive	58	21	(68)
Asset retirement obligation settlement	(81)	(87)	(88)
Major plant outage deferral	(32)	20	2
Other — net assets	84	(17)	(27)
Other — net liabilities	(243)	(330)	235
Cash provided by (used in) operating activities	5,453	485	(206)
Cash flows — investing activities:			
Capital expenditures, including nuclear fuel purchases and LTSA prepayments	(1,676)	(1,301)	(1,033)
Proceeds from sales of nuclear decommissioning trust fund securities	601	670	483
Investments in nuclear decommissioning trust fund securities	(624)	(693)	(505)
Proceeds from sales of environmental allowances	500	1,275	392
Purchases of environmental allowances	(1,071)	(1,303)	(605)

VISTRA CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions of Dollars)

	Year Ended December 31,		
	2023	**2022**	**2021**
Cash flows — financing activities:			
Issuances of preferred stock	—	—	2,000
Issuances of long-term debt	2,498	1,498	1,250
Repayments/repurchases of debt	(33)	(251)	(381)
Borrowings under Term Loan A	—	—	1,250
Repayment under Term Loan A	—	—	(1,250)
Proceeds from forward capacity agreement	—	—	500
Net borrowings/(repayments) under accounts receivable financing	(425)	425	(300)
Borrowings under Revolving Credit Facility	100	1,750	1,450
Repayments under Revolving Credit Facility	(350)	(1,500)	(1,450)
Borrowings under Commodity-Linked Facility	—	3,150	—
Repayments under Commodity-Linked Facility	(400)	(2,750)	—
Debt issuance costs	(59)	(31)	(13)
Stock repurchases	(1,245)	(1,949)	(471)
Dividends paid to common stockholders	(313)	(302)	(290)
Dividends paid to preferred stockholders	(150)	(151)	—
Other, net	83	31	(21)
Cash provided by (used in) financing activities	(294)	(80)	2,274
Net change in cash, cash equivalents and restricted cash	3,014	(834)	915
Cash, cash equivalents and restricted cash — beginning balance	525	1,359	444
Cash, cash equivalents and restricted cash — ending balance	$ 3,539	$ 525	$ 1,359

See Notes to the Consolidated Financial Statements.

VISTRA CORP.
CONSOLIDATED BALANCE SHEETS
(Millions of Dollars)

	December 31,	
	2023	**2022**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 3,485	$ 455
Restricted cash (Note 22)	40	37
Trade accounts receivable — net (Note 22)	1,674	2,059
Income taxes receivable	6	27
Inventories (Note 22)	740	570
Commodity and other derivative contractual assets (Note 17)	3,645	4,538
Margin deposits related to commodity contracts	1,244	3,137
Margin deposits posted under affiliate financing agreement (Note 11)	439	—
Prepaid expense and other current assets	364	293
Total current assets	11,637	11,116
Restricted cash (Note 22)	14	33
Investments (Note 22)	2,035	1,729
Property, plant and equipment — net (Note 22)	12,432	12,554
Operating lease right-of-use assets (Note 13)	50	51
Goodwill (Note 6)	2,583	2,583
Identifiable intangible assets — net (Note 6)	1,864	1,958
Commodity and other derivative contractual assets (Note 17)	577	702
Accumulated deferred income taxes (Note 7)	1,223	1,710
Other noncurrent assets	551	351
Total assets	$ 32,966	$ 32,787
LIABILITIES AND EQUITY		
Current liabilities:		
Short-term borrowings (Note 12)	$ —	$ 650
Accounts receivable financing (Note 10)	—	425
Long-term debt due currently (Note 12)	2,286	38
Trade accounts payable	1,147	1,556
Commodity and other derivative contractual liabilities (Note 17)	5,258	6,610
Margin deposits related to commodity contracts	45	39
Accrued taxes other than income	203	199
Accrued interest	206	160
Asset retirement obligations (Note 22)	124	128
Operating lease liabilities (Note 13)	7	8
Other current liabilities	547	524
Total current liabilities	9,823	10,337
Margin deposits financing with affiliate (Note 11)	439	—
Long-term debt, less amounts due currently (Note 12)	12,116	11,933
Operating lease liabilities (Note 13)	48	45
Commodity and other derivative contractual liabilities (Note 17)	1,688	1,726
Accumulated deferred income taxes (Note 7)	1	1
Tax Receivable Agreement obligation (Note 8)	164	514
Asset retirement obligations (Note 22)	2,414	2,309

VISTRA CORP.
CONSOLIDATED BALANCE SHEETS
(Millions of Dollars)

	December 31,	
	2023	**2022**
Other noncurrent liabilities and deferred credits (Note 22)	951	1,004
Total liabilities	27,644	27,869
Commitments and Contingencies (Note 14)		
Total equity (Note 15):		
Preferred stock, number of shares authorized — 100,000,000; Series A (liquidation preference — $1,000; shares outstanding: December 31, 2023 and 2022 — 1,000,000; Series B (liquidation preference — $1,000; shares outstanding: December 31, 2023 and 2022 — 1,000,000; Series C (liquidation preference — $1,000; shares outstanding: December 31, 2023 — 476,081; December 31, 2022 — zero)	2,476	2,000
Common stock (par value — $0.01; number of shares authorized — 1,800,000,000) (shares outstanding: December 31, 2023 — 351,457,016; December 31, 2022 — 389,754,870)	5	5
Treasury stock, at cost (shares: December 31, 2023 — 192,178,156; December 31, 2022 — 147,424,202)	(4,662)	(3,395)
Additional paid-in-capital	10,095	9,928
Retained deficit	(2,613)	(3,643)
Accumulated other comprehensive income	6	7
Stockholders' equity	5,307	4,902
Noncontrolling interest in subsidiary	15	16
Total equity	5,322	4,918
Total liabilities and equity	$ 32,966	$ 32,787

See Notes to the Consolidated Financial Statements.

VISTRA CORP.
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
(Millions of Dollars)

	Preferred Stock	Common Stock	Treasury Stock	Additional Paid-In Capital	Retained Deficit	Accumulat Other Comprehen Income (Lo
Balances at December 31, 2020	$ —	$ 5	$ (973)	$ 9,786	$ (399)	$ (48)
Series A Preferred Stock issued	1,000	—	—	(10)	—	—
Series B Preferred Stock issued	1,000	—	—	(15)	—	—
Stock repurchases	—	—	(585)	—	—	—
Effects of stock-based compensation	—	—	—	60	—	—
Net income (loss)	—	—	—	—	(1,274)	—
Dividends declared on common stock	—	—	—	—	(290)	—
Change in accumulated other comprehensive income (loss)	—	—	—	—	—	32
Investment by noncontrolling interest	—	—	—	—	—	—
Other	—	—	—	3	(1)	—
Balances at December 31, 2021	$ 2,000	$ 5	$ (1,558)	$ 9,824	$ (1,964)	$ (16)
Stock repurchases	—	—	(1,837)	—	—	—
Effects of stock-based compensation	—	—	—	103	—	—
Net income (loss)	—	—	—	—	(1,227)	—
Dividends declared on common stock	—	—	—	—	(302)	—
Dividends declared on preferred stock	—	—	—	—	(151)	—
Change in accumulated other comprehensive income (loss)	—	—	—	—	—	23

See Notes to the Consolidated Financial Statements.

VISTRA CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. BUSINESS AND SIGNIFICANT ACCOUNTING POLICIES

Description of 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 of Terms and Abbreviations* for defined terms.

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.

Vistra has six reportable segments: (i) Retail, (ii) Texas, (iii) East, (iv) West, (v) Sunset and (vi) Asset Closure. See Note 21 for further information concerning our reportable business segments.

Transaction Agreement

On March 6, 2023, Vistra Operations and Merger Sub entered into a transaction agreement (Transaction Agreement) with Energy Harbor pursuant to which, upon the terms and subject to the conditions thereof, Merger Sub will be merged with and into Energy Harbor, with Energy Harbor surviving as an indirect subsidiary of Vistra (Merger, and collectively with the other transactions contemplated by the Transaction Agreement, the Transactions). The Transaction Agreement, the Merger and the other Transactions were approved by each of Vistra's board of directors (Board) and Energy Harbor's board of directors. On February 16, 2024, we received approval from FERC to acquire Energy Harbor. FERC's approval was the last regulatory approval needed, and we anticipate closing on March 1, 2024. See Note 2 for more information concerning the Transaction Agreement.

Winter Storm Uri

In February 2021, a severe winter storm with extremely cold temperatures affected much of the U.S., including Texas. This severe weather resulted in surging demand for power, natural gas supply shortages, operational challenges for generators, and a significant load shed event that was ordered by ERCOT beginning on February 15, 2021 and continuing through February 18, 2021. Winter Storm Uri had a material adverse impact on our 2021 results of operations and operating cash flows.

As part of the 2021 regular Texas legislative sessions and in response to extraordinary costs incurred by electricity market participants during Winter Storm Uri, the Texas legislature passed House Bill (HB) 4492 for ERCOT to obtain financing to distribute to load-serving entities (LSEs) that were uplifted and paid to ERCOT exceptionally high price adders and ancillary service costs during Winter Storm Uri. In October 2021, the PUCT issued a Debt Obligation Order approving $2.1 billion financing and the methodology for allocation of proceeds to the LSEs. In December 2021, ERCOT finalized the amount of allocations to the LSEs, and we received $544 million of proceeds from ERCOT in the second quarter of 2022. The Company accounted for the proceeds we received by analogy to the contribution model within Accounting Standards Codification (ASC) 958-605, *Not-for-Profit Entities - Revenue Recognition* and the grant model within International Accounting Standard 20, *Accounting for Government Grants and Disclosure of Government Assistance*, as a reduction to expenses in the statements of operations in the annual period for which the proceeds are intended to compensate. We concluded that the threshold for recognizing a receivable was met in December 2021 as the amounts to be received were determinable and ERCOT was directed by its governing body, the PUCT, to take all actions required to effectuate the $2.1 billion funding approved in the Debt Obligation Order. The final financial impact of Winter Storm Uri continues to be subject to the outcome of litigation arising from the event.

Recent Developments

See Note 8 for information on the 2024 TRA Rights repurchases and tender offer, Note 12 for information on the January 2024 Senior Secured Notes Tender Offer and Note 15 for information on the February 2024 declaration of common and preferred stock dividends and the additional $1.5 billion authorization under the Share Repurchase Program.

Significant Accounting Policies

Basis of Presentation

The consolidated financial statements have been prepared in accordance with U.S. GAAP and on the same basis as the audited financial statements included in our 2022 Form 10-K. All intercompany items and transactions have been eliminated in consolidation. All dollar amounts in the financial statements and tables in the notes are stated in millions of U.S. dollars unless otherwise indicated. Certain prior period amounts have been reclassified to conform with the current year presentation.

Use of Estimates

Preparation of financial statements requires estimates and assumptions about future events that affect the reporting of assets and liabilities as of the balance sheet dates and the reported amounts of revenue and expense, including fair value measurements, estimates of expected obligations, judgments related to the potential timing of events and other estimates. In the event estimates and/or assumptions prove to be different from actual amounts, adjustments are made in subsequent periods to reflect more current information.

Derivative Instruments and Mark-to-Market Accounting

We enter into contracts for the purchase and sale of electricity, natural gas, coal and other commodities utilizing instruments such as options, swaps, futures and forwards primarily to manage commodity price and interest rate risks. If the instrument meets the definition of a derivative under accounting standards related to derivative instruments and hedging activities, changes in the fair value of the derivative are recognized in net income as unrealized gains and losses. This recognition is referred to as mark-to-market accounting. The fair values of our unsettled derivative instruments under mark-to-market accounting are reported in the consolidated balance sheets as commodity and other derivative contractual assets or liabilities. We report derivative assets and liabilities in the consolidated balance sheets without taking into consideration netting arrangements we have with counterparties. Margin deposits that contractually offset these assets and liabilities are reported separately in the consolidated balance sheets, except for certain margin amounts related to changes in fair value on CME transactions that are legally characterized as settlement of derivative contracts rather than collateral. When derivative instruments are settled and realized gains and losses are recorded, the previously recorded unrealized gains and losses and derivative assets and liabilities are reversed. See Notes 16 and 17 for additional information regarding fair value measurement and commodity and other derivative contractual assets and liabilities. A commodity-related derivative contract may be designated as a normal purchase or sale if the commodity is to be physically received or delivered for use or sale in the normal course of business. If designated as normal, the derivative contract is accounted for under the accrual method of accounting (not marked-to-market) with no balance sheet or income statement recognition of the contract until settlement.

Because derivative instruments are frequently used as economic hedges, accounting standards related to derivative instruments and hedging activities allow for hedge accounting, which provides for the designation of such instruments as cash flow or fair value hedges if certain conditions are met. As of December 31, 2023 and 2022, there were no derivative positions accounted for as cash flow or fair value hedges.

We report commodity hedging and trading results as revenue, fuel expense or purchased power in the consolidated statements of operations depending on the type of activity. Electricity hedges, financial natural gas hedges and trading activities are primarily reported as revenue. Physical or financial hedges for coal or fuel oil, along with physical natural gas trades, are primarily reported as fuel expense. Realized and unrealized gains and losses associated with interest rate swap transactions are reported in the consolidated statements of operations in interest expense.

Revenue Recognition

Revenue is recognized when electricity is delivered to our customers in an amount that we expect to invoice for volumes delivered or services provided. Sales tax is excluded from revenue. Energy sales and services that have been delivered but not billed by period end are estimated. Accrued unbilled revenues are based on estimates of customer usage since the date of the last meter reading provided by the independent system operators or electric distribution companies. Estimated amounts are adjusted when actual usage is known and billed.

We record wholesale generation revenue when volumes are delivered or services are performed for transactions that are not accounted for on a mark-to-market basis. These revenues primarily consist of physical electricity sales to the ISO/RTO, ancillary service revenue for reliability services, capacity revenue for making installed generation and demand response available for system reliability requirements, and certain other electricity sales contracts. See Note 5 for detailed descriptions of revenue from contracts with customers. See *Derivative Instruments and Mark-to-Market Accounting* for revenue recognition related to derivative contracts.

Impairment of Long-Lived Assets

We evaluate long-lived assets (including intangible assets with finite lives) for impairment whenever indications of impairment exist. The carrying value of such assets is deemed to be impaired if the projected undiscounted cash flows are less than the carrying value. If there is such impairment, a loss is recognized based on the amount by which the carrying value exceeds the fair value. Fair value is determined primarily by discounted cash flows, supported by available market valuations, if applicable. See Note 22 for details of impairments of long-lived assets recorded.

Finite-lived intangibles identified as a result of fresh start reporting or purchase accounting are amortized over their estimated useful lives based on the expected realization of economic effects. See Note 6 for details of intangible assets with finite lives, including discussion of fair value determinations.

Goodwill and Intangible Assets with Indefinite Lives

As part of fresh start reporting and purchase accounting, reorganization value or the purchase consideration is generally allocated, first, to identifiable tangible assets and liabilities, identifiable intangible assets and liabilities, then any remaining excess reorganization value or purchase consideration is allocated to goodwill. We evaluate goodwill and intangible assets with indefinite lives for impairment at least annually, or when indications of impairment exist. We have established October 1 as the date we evaluate goodwill and intangible assets with indefinite lives for impairment. See Note 6 for details of goodwill and intangible assets with indefinite lives, including discussion of fair value determinations.

Nuclear Fuel

Nuclear fuel is capitalized and reported as a component of our property, plant and equipment in our consolidated balance sheets. Amortization of nuclear fuel is calculated on the units-of-production method and is reported as a component of fuel, purchased power costs and delivery fees in our consolidated statements of operations.

Major Maintenance Costs

Major maintenance costs incurred during generation plant outages are deferred and amortized into operating costs over the period between the major maintenance outages for the respective asset. Other routine costs of maintenance activities are charged to expense as incurred and reported as operating costs in our consolidated statements of operations.

Defined Benefit Pension Plans and OPEB Plans

Certain health care and life insurance benefits are offered to eligible employees and their dependents upon the retirement of such employees from the company. Pension benefits are offered to eligible employees under collective bargaining agreements based on either a traditional defined benefit formula or a cash balance formula. Costs of pension and OPEB plans are dependent upon numerous factors, assumptions and estimates.

See Note 18 for additional information regarding pension and OPEB plans.

Stock-Based Compensation

Stock-based compensation is accounted for in accordance with ASC 718, *Compensation - Stock Compensation.* We recognize compensation expense for graded vesting awards on a straight-line basis over the requisite service period for the entire award. Forfeitures are recognized as they occur. See Note 19 for additional information regarding stock-based compensation.

Sales and Excise Taxes

Sales and excise taxes are accounted for as "pass through" items on the consolidated balance sheets with no effect on the consolidated statements of operations (*i.e.*, the tax is billed to customers and recorded as trade accounts receivable with an offsetting amount recorded as a liability to the taxing jurisdiction in other current liabilities in our consolidated statements of operations).

Franchise and Revenue-Based Taxes

Unlike sales and excise taxes, franchise and revenue-based taxes are not "pass through" items. These taxes are imposed on us by state and local taxing authorities, based on revenues or kWh delivered, as a cost of doing business and are recorded as an expense. Rates we charge to customers are intended to recover our costs, including the franchise and revenue-based receipt taxes, but we are not acting as an agent to collect the taxes from customers. We report franchise and revenue-based taxes in SG&A expense in our consolidated statements of operations.

Income Taxes

Investment tax credits which are not transferable or refundable under the IRA are accounted for using the deferral method, which reduces the basis of our solar and battery storage facilities. As of both December 31, 2023 and 2022, deferred tax assets related to these credits totaled $70 million.

Deferred income taxes are provided for temporary differences between the book and tax basis of assets and liabilities as required under accounting rules. See Note 7.

We report interest and penalties related to uncertain tax positions as current income tax expense. See Note 7.

Tax Receivable Agreement (TRA)

The Company accounts for its obligations under the TRA as a liability in our consolidated balance sheets (see Note 8). The carrying value of the TRA obligation represents the discounted amount of projected payments under the TRA. The projected payments are based on certain assumptions, including but not limited to (a) the federal corporate income tax rate, (b) estimates of our taxable income in the current and future years and (c) additional states that Vistra operates in, including the relevant tax rate and apportionment factor for each state. Our taxable income takes into consideration the current federal tax code and reflects our current estimates of future results of the business.

The carrying value of the obligation is being accreted to the amount of the gross expected obligation using the effective interest method. Changes in the estimated amount of this obligation resulting from changes to either the timing or amount of TRA payments are recognized in the period of change and measured using the discount rate inherent in the initial fair value of the obligation. These changes are included on our consolidated statements of operations under the heading of Impacts of Tax Receivable Agreement.

Accounting for Contingencies

Our financial results may be affected by judgments and estimates related to loss contingencies. Accruals for loss contingencies are recorded when management determines that it is probable that a liability has been incurred and that such economic loss can be reasonably estimated. Such determinations are subject to interpretations of current facts and circumstances, forecasts of future events and estimates of the financial impacts of such events. See Note 14 for a discussion of contingencies.

Cash and Cash Equivalents

For purposes of reporting cash and cash equivalents, temporary cash investments purchased with an original maturity of three months or less are considered cash equivalents.

Restricted Cash

The terms of certain agreements require the restriction of cash for specific purposes. See Note 22 for more details regarding restricted cash.

Property, Plant and Equipment

Property, plant and equipment has been recorded at estimated fair values at the time of acquisition for assets acquired or at cost for capital improvements and individual facilities developed (see Note 3). Significant improvements or additions to our property, plant and equipment that extend the life of the respective asset are capitalized at cost, while other costs are expensed when incurred. The cost of self-constructed property additions includes materials and both direct and indirect labor, including payroll-related costs. Interest related to qualifying construction projects and qualifying software projects is capitalized in accordance with accounting guidance related to capitalization of interest cost. See Note 22.

Depreciation of our property, plant and equipment (except for nuclear fuel) is calculated on a straight-line basis over the estimated service lives of the properties. Depreciation expense is calculated on an asset-by-asset basis. Estimated depreciable lives are based on management's estimates of the assets' economic useful lives. See Note 22.

Asset Retirement Obligations (ARO)

A liability is initially recorded at fair value for an asset retirement obligation associated with the legal obligation associated with law, regulatory, contractual or constructive retirement requirements of tangible long-lived assets in the period in which it is incurred if a fair value is reasonably estimable. At initial recognition of an ARO obligation, an offsetting asset is also recorded for the long-lived asset that the liability corresponds with, which is subsequently depreciated over the estimated useful life of the asset. These liabilities primarily relate to our nuclear generation plant decommissioning, land reclamation related to lignite mining and removal of lignite/coal-fueled plant ash treatment facilities. Over time, the liability is accreted for the change in present value and the initial capitalized costs are depreciated over the remaining useful lives of the assets. Generally, changes in estimates related to ARO obligations are recorded as increases or decreases to the liability and related asset as information becomes available. Changes in estimates related to assets that have been retired or for which costs are not recoverable are recorded as operating costs in the consolidated statements of operations. See Note 22.

Regulatory Asset or Liability

The costs to ultimately decommission the Comanche Peak nuclear power plant are recoverable through the regulatory rate making process as part of Oncor's delivery fees. As a result, the asset retirement obligation and the investments in the decommissioning trust are accounted for as rate regulated operations. Changes in these accounts, including investment income and accretion expense, do not impact net income, but are reported as a change in the corresponding regulatory asset or liability balance that is reflected in our consolidated balance sheets as other noncurrent assets or other noncurrent liabilities and deferred credits.

Inventories

Inventories consist of materials and supplies, fuel stock and natural gas in storage. Materials and supplies inventory is valued at weighted average cost and is expensed or capitalized when used for repairs/maintenance or capital projects, respectively. Fuel stock and natural gas in storage are reported at the lower of cost (calculated on a weighted average basis) or net realizable value. We expect to recover the value of inventory costs in the normal course of business. See Note 22.

Investments

Investments in a nuclear decommissioning trust fund are carried at current market value in the consolidated balance sheets. Assets related to employee benefit plans represent investments held to satisfy deferred compensation liabilities and are recorded at current market value. See Note 22 for discussion of these and other investments.

Treasury Stock

Treasury stock purchases are accounted for under the cost method whereby the entire cost of the acquired stock is recorded as treasury stock, which is presented in our consolidated balance sheets as a reduction to additional paid-in capital. Treasury stock purchases made by third party brokers on our behalf are recorded on a trade date basis when we are contractually obligated to pay the broker for their repurchase costs. See Note 15.

Leases

At the inception of a contract we determine if it is or contains a lease, which involves the contract conveying the right to control the use of explicitly or implicitly identified property, plant, or equipment for a period of time in exchange for consideration.

Right-of-use (ROU) assets represent our right to use an underlying asset for the lease term and lease liabilities represent our obligation to make lease payments arising from the lease. ROU assets and lease liabilities are recognized at the commencement date of the underlying lease based on the present value of lease payments over the lease term. We use our secured incremental borrowing rate based on the information available at the lease commencement date to determine the present value of lease payments. Operating leases are included in operating lease ROU assets, operating lease liabilities (current) and operating lease liabilities (noncurrent) on our consolidated balance sheet. Finance leases are included in property, plant and equipment, other current liabilities and other noncurrent liabilities and deferred credits on our consolidated balance sheet. Lease term includes options to extend or terminate the lease when it is reasonably certain that we will exercise the option. We apply the practical expedient permitted by ASC *842, Leases* to not separate lease and non-lease components for a majority of our lease asset classes.

Leases with an initial lease term of 12 months or less are not recorded on the balance sheet; we recognize lease expense for these leases on a straight-line basis over the lease term.

We also present lessor sublease income on a net basis against the related lessee lease expense.

Adoption of Accounting Standards Issued in 2023

Improvements to Reportable Segment Disclosures — In November 2023, the Financial Accounting Standards Board (FASB) issued ASU No. 2023-07, *Segment Reporting (Topic 280), Improvements to Reportable Segment Disclosures*, to improve the disclosures about reportable segments and add more detailed information about a reportable segment's expenses. The amendments in the ASU require public entities to disclose on an annual and interim basis significant segment expenses that are regularly provided to the chief operating decision maker (CODM) and included within each reported measure of segment profit or loss, other segment items by reportable segment, the title and position of the CODM, and an explanation of how the CODM uses the reported measures of segment profit or loss in assessing segment performance and deciding how to allocate resources. The ASU does not change the definition of a segment, the method for determining segments, the criteria for aggregating operating segments into reportable segments, or the current specifically enumerated segment expenses that are required to be disclosed. The Company will adopt the amendments in this ASU for its fiscal year ended December 31, 2024 and interim periods within its fiscal year ended December 31, 2025. The amendment will be applied retrospectively to all prior periods presented. We are currently evaluating the impact this ASU will have on our consolidated financial statements and related disclosures.

Improvements to Income Tax Disclosures — In December 2023, the FASB issued ASU No. 2023-09 (ASU 2023-09), *Income Taxes (Topic 740): Improvements to Income Tax Disclosures* to enhance the transparency and decision usefulness of income tax disclosures. ASU 2023-09 is effective for annual periods beginning after December 15, 2024 on a prospective basis. Early adoption is permitted. As the amendments apply to income tax disclosures only, the Company does not expect adoption to have a material impact on our consolidated financial statements.

Adoption of Accounting Standards Issued Prior to 2023

Facilitation of the Effects of Reference Rate Reform on Financial Reporting

In March 2020, the FASB issued ASU 2020-04, *Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting*. The ASU provides optional expedients and exceptions for applying GAAP to contract modifications and hedging relationships, subject to meeting certain criteria, that reference LIBOR or another rate that is expected to be discontinued. The amendments in the ASU were effective for all entities as of March 12, 2020 through December 31, 2022.

In December 2022, the FASB issued ASU 2022-06, *Reference Rate Reform (Topic 848): Deferral of the Sunset Date of Topic 848*, which deferred the sunset date of Topic 848 from December 31, 2022 to December 31, 2024. The expedients and exceptions may be elected over time as reference rate reform activities occur through the sunset date. We have applied the optional expedients to amendments to financial instruments that now reference the Secured Overnight Financing Rate (SOFR). Additionally, we have identified the financial instruments to which the expedients could be applied, if deemed necessary, as amendments to these financial instruments are made through the sunset date.

Disclosures by Business Entities about Government Assistance

In November 2021, the Financial Accounting Standards Board issued ASU 2021-10, *Government Assistance (Topic 832) Disclosures by Business Entities about Government Assistance*. This standard requires additional annual disclosures when a business receives government assistance and uses a grant or contribution accounting model by analogy to other accounting guidance such as the grant model under International Accounting Standards 20, *Accounting for Government Grants and Disclosures of Government Assistance* (IAS 20) and GAAP ASC 958-605, *Not-for-Profit Entities - Revenue Recognition*. The standard was effective January 1, 2022 with early adoption permitted. As further discussed in Note 1, we made disclosures in accordance with this guidance when accounting for the *Uplift Securitization Proceeds from ERCOT.*

Due to the enactment of the IRA, the Company qualifies for tax incentives through eligible construction spending and production. These tax incentives generally provide for refundable or transferable tax credits upon the applicable qualifying event for the credit type, typically production or in-service date. Transferable and refundable PTCs are included in other noncurrent assets in the consolidated balance sheet and included in revenues in the consolidated statements of operations when receipt of the credit is reasonably assured. Transferable investment tax credits (ITCs) are included in other noncurrent assets on the consolidated balance sheet with a corresponding reduction to the cost basis of the Company's plant assets when receipt of the credit is reasonably assured, and reduces depreciation expense over the life of the asset. We believe the reasonable assurance term as used in IAS 20 is analogous to the term probable as defined in ASC 450-20 of U.S. GAAP. The Company accounts for the credits we expect to receive by analogy to the grant model within IAS 20, as U.S. GAAP does not address how to account for these tax credits.

2. TRANSACTION AGREEMENT

On March 6, 2023, Vistra Operations and Merger Sub entered into the Transaction Agreement with Energy Harbor pursuant to which, upon the terms and subject to the conditions thereof, Merger Sub will be merged with and into Energy Harbor, with Energy Harbor surviving as an indirect subsidiary of Vistra. The Transaction Agreement, the Merger and the other Transactions were approved by each of Vistra's Board and Energy Harbor's board of directors.

Subject to the terms and conditions of the Transaction Agreement, prior to the consummation of the Merger, Vistra will cause certain of its affiliates to transfer certain of its affiliate entities, including Merger Sub, to an indirect wholly owned subsidiary of Vistra (Vistra Vision).

Subject to the terms and conditions of the Transaction Agreement, at the effective time of the Merger (Effective Time), the issued and outstanding shares of Energy Harbor common stock other than shares that are being exchanged by certain funds and accounts managed by Nuveen Asset Management LLC and certain funds managed by Avenue Capital Management II, L.P. (Rollover Holders) for 15% of the direct or indirect equity interests in Vistra Vision, and certain other shares, each as specified in the Transaction Agreement and the Contribution and Exchange Agreements (as defined below) will be cancelled and extinguished and automatically converted into the right to receive cash consideration per share payable in the Merger. Vistra's transfer of cash and equity in Vistra Vision in exchange for the issued and outstanding shares of Energy Harbor common stock will be covered under the non-recognition provisions of the Internal Revenue Code. The Aggregate Base Transaction Value is defined in the Transaction Agreement to be (a) the Aggregate Cash Consideration Value (defined in the Transaction Agreement to be $3.0 billion), plus (b) for the 15% equity in Vistra Vision, the Aggregate Equity Consideration Value (defined in the Transaction Agreement to be $3.333 billion for the purpose of determining the amount per share to be distributed to Energy Harbor's stockholders), minus (c) certain adjustments as specified in the Transaction Agreement. In addition, in connection with the Merger, Energy Harbor's equity awards will be cancelled for cash based on the per share Merger consideration for the shares underlying such equity awards and Energy Harbor's stockholders (including Rollover Holders and holders of Energy Harbor equity awards) will receive an additional amount of cash paid from Energy Harbor to the extent of Energy Harbor's unrestricted cash on hand as of the closing, subject to certain adjustments as specified in the Transaction Agreement. In addition, Vistra Operations will pay up to $100 million of Energy Harbor's transaction expenses.

On February 16, 2024, we received approval from FERC to acquire Energy Harbor, which was the last regulatory approval needed to close the acquisition. Consummation of the Transactions is subject to customary closing conditions, and we anticipate closing on March 1, 2024.

Vistra Vision will combine Energy Harbor's nuclear and retail businesses with Vistra's nuclear and retail businesses and certain of the Vistra Zero renewables and energy storage projects. This combination is expected to create a leading integrated retail electricity and zero-carbon generation company with the second-largest competitive nuclear fleet in the U.S., along with a growing renewables and energy storage portfolio. This transaction is expected to accelerate Vistra's path to a clean energy transition by more than doubling the amount of zero-carbon generation it has online at the time of the Transactions' closing.

Financing Arrangements

In connection with the Transactions, in March 2023, Vistra Operations entered into a debt commitment letter (Commitment Letter) and related fee letters with various lenders (Commitment Parties), pursuant to which, and subject to the terms and conditions set forth therein, the Commitment Parties committed to provide (a) up to approximately $3.0 billion in an aggregate principal amount of senior secured bridge loans under a 364-day senior secured bridge loan credit facility (Acquisition Bridge Facility), (b) in the event Vistra Operations did not obtain certain required consents and amendments from the lenders under the Vistra Operations Credit Agreement, a 364-day senior secured term loan B bridge facility in an aggregate principal amount of up to approximately $2.5 billion (TLB Refinancing Bridge Facility) and (c) in the event Vistra Operations did not obtain certain required consents and amendments from the lenders under the Vistra Operations Commodity-Linked Credit Agreement, a replacement commodity-linked revolving credit facility in an aggregate principal amount up to $300 million (Refinancing Commodity-Linked Revolving Credit Facility). Vistra Operations subsequently obtained commitments from the lenders under the Vistra Operations Credit Agreement and Vistra Operations Commodity-Linked Credit Agreement to provide the required consents and amendments which resulted in the termination of the commitments for each of the TLB Refinancing Bridge Facility and the Refinancing Commodity-Linked Revolving Credit Facility. In September 2023, the Acquisition Bridge Facility was terminated as a result of the issuance of $1.75 billion of a combination of senior secured and senior unsecured notes by Vistra Operations in September 2023 that are expected to be used, together with cash on hand, to fund the Transactions. Fees related to the Commitment Letter totaled $21 million in the year ended December 31, 2023 which were classified as interest expense and related charges in the consolidated statement of operations.

3. DEVELOPMENT OF GENERATION FACILITIES

Texas Segment Solar Generation and Energy Storage Projects

In connection with our previously announced renewable development plans in Texas, 158 MW of solar generation came online in January and February 2022 and 260 MW of battery ESS came online in April 2022. Estimated commercial operation dates for the remaining facilities to be developed are expected to be 2025 and beyond, but we will only invest in growth projects if we are confident that the expected returns will meet or exceed internal targets. As of December 31, 2023, we had accumulated approximately $200 million in construction-work-in-process for these remaining Texas segment solar generation projects.

East Segment Solar Generation and Energy Storage Projects

In September 2021, we announced the planned development of 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, based on the passage of Illinois Senate Bill 2408, the Energy Transition Act. Estimated commercial operation dates for these facilities range from 2024 to 2026. As of December 31, 2023, we had accumulated approximately $66 million in construction-work-in-process for these East segment solar generation and battery ESS projects.

West Segment Energy Storage Projects

Moss Landing

In June 2018, we announced that, subject to approval by the CPUC, we would enter into a 20-year resource adequacy contract with PG&E to develop a 300 MW battery ESS at our Moss Landing Power Plant site in California (Moss Landing Phase I). The CPUC approved the resource adequacy contract in November 2018. Under the contract, PG&E will pay us a fixed monthly resource adequacy payment, while we will receive the energy revenues and incur the costs from dispatching and charging the battery ESS. Moss Landing Phase I commenced commercial operations in May 2021.

In May 2020, we announced that, subject to approval by the CPUC, we would enter into a 10-year resource adequacy contract with PG&E to develop an additional 100 MW battery ESS at our Moss Landing Power Plant site (Moss Landing Phase II). The CPUC approved the resource adequacy contract in August 2020. Moss Landing Phase II commenced commercial operations in July 2021.

In January 2022, we announced that, subject to approval by the CPUC, we would enter into a 15-year resource adequacy and energy settlement contract with PG&E to develop an additional 350 MW battery ESS at our Moss Landing Power Plant site (Moss Landing Phase III). The CPUC approved the resource adequacy and energy settlement contract in April 2022. Moss Landing Phase III commenced commercial operations in June 2023. As a result of reaching commercial operations, we recognized $154 million of transferable ITCs associated with the project within other noncurrent assets in the consolidated balance sheet.

Moss Landing Outages

In September 2021, Moss Landing Phase I experienced an incident impacting a portion of the battery ESS. A review found the root cause originated in systems separate from the battery system. The facility was offline as we performed the work necessary to return the facility to service. Restoration work on the facility was completed in June 2022. Moss Landing Phases II and III were not affected by this incident.

In February 2022, Moss Landing Phase II experienced an incident impacting a portion of the battery ESS. A review found the root cause originated in systems separate from the battery system. The facility was offline as we performed the work necessary to return the facility to service. Restoration work on the facility was completed in September 2022. Moss Landing Phases I and III were not affected by this incident.

These incidents did not have a material impact on our results of operations.

4. RETIREMENT OF GENERATION FACILITIES

Operational results for plants with defined retirement dates are included in our Sunset segment beginning in the quarter when a retirement plan is announced and move to the Asset Closure segment at the beginning of the calendar year the retirement is expected to occur.

Facility	Location	ISO/RTO	Fuel Type	Net Generation Capacity (MW)	Actual or Expected Retirement Date (a)(b)	Segment
Baldwin	Baldwin, IL	MISO	Coal	1,185	By the end of 2025	Sunset
Coleto Creek	Goliad, TX	ERCOT	Coal	650	By the end of 2027	Sunset
Kincaid	Kincaid, IL	PJM	Coal	1,108	By the end of 2027	Sunset
Miami Fort	North Bend, OH	PJM	Coal	1,020	By the end of 2027	Sunset
Newton	Newton, IL	MISO/ PJM	Coal	615	By the end of 2027	Sunset
Edwards	Bartonville, IL	MISO	Coal	585	Retired January 1, 2023	Asset Closure
Joppa	Joppa, IL	MISO	Coal	802	Retired September 1, 2022	Asset Closure
Joppa	Joppa, IL	MISO	Natural Gas	221	Retired September 1, 2022	Asset Closure
Zimmer	Moscow, OH	PJM	Coal	1,300	Retired June 1, 2022	Asset Closure
Total				7,486		

(a) Generation facilities may retire earlier than expected dates disclosed if economic or other conditions dictate.
(b) Retirement dates represent the first full day in which a plant does not operate.

In 2020, we announced our intention to retire all of our remaining coal generation facilities in Illinois and Ohio, one coal generation facility in Texas and one natural gas facility in Illinois no later than year-end 2027 due to economic challenges, including incremental expenditures that would be required to comply with the CCR rule and ELG rule (see Note 14), and in furtherance of our efforts to significantly reduce our carbon footprint. As previously announced in April 2021, we retired the Joppa generation facilities in September 2022 in order to settle a complaint filed with the Illinois Pollution Control Board (IPCB) by the Sierra Club in 2018. As previously announced in July 2021, we retired the Zimmer coal generation facility in June 2022 due to the inability to secure capacity revenues for the plant in the PJM capacity auction held in May 2021.

See Note 22 for discussion of impairments recorded in connection with these determinations.

5. REVENUE

Revenue Disaggregation

The following tables disaggregate our revenue by major source:

	Year Ended December 31, 2023					
	Retail	Texas	East	West	Sunset	Asset Closure
Revenue from contracts with customers:						
Retail energy charge in ERCOT	$ 7,674	$ —	$ —	$ —	$ —	$ —
Retail energy charge in Northeast/ Midwest	1,642	—	—	—	—	—
Wholesale generation revenue from ISO/ RTO	—	1,060	1,036	421	392	—
Capacity revenue from ISO/ RTO (a)	—	—	57	—	41	—
Revenue from other wholesale contracts	—	505	654	179	143	—
Total revenue from contracts with customers	9,316	1,565	1,747	600	576	—
Other revenues:						
Intangible amortization	(1)	—	(2)	—	(3)	—
Transferable PTC revenues	—	10	—	—	—	—
Hedging and other revenues (b)	1,257	(1,611)	277	310	736	—
Affiliate sales (c)	—	3,859	2,193	4	522	—
Total other revenues	1,256	2,258	2,468	314	1,255	—
Total revenues	$ 10,572	$ 3,823	$ 4,215	$ 914	$ 1,831	$ —

(a) Represents net capacity sold (purchased) in each ISO/RTO. The East segment includes $157 million of capacity sold offset by $100 million of capacity purchased. The Sunset segment includes $76 million of capacity sold offset by $35 million of capacity purchased.

(b) Includes $714 million of unrealized net gains from mark-to-market valuations of commodity positions.

For the year ended	Retail	Texas	East	West	Sunset	A Cl
December 31, 2023	$ 191	$ (758)	$ 1,165	$ 237	$ 603	$ 3

(1) Amounts attributable to generation segments offset in fuel, purchased power costs and delivery fees in the Retail segment, with no impact to consolidated results.

(c) East and Sunset segments include $641 million and $187 million, respectively, of affiliated unrealized net gains, and Texas segment includes $62 million of affiliated unrealized net losses from mark-to-market valuations of commodity positions with the Retail segment.

	Year Ended December 31, 2022					
	Retail	Texas	East	West	Sunset	Asset Closure
Revenue from contracts with customers:						
Retail energy charge in ERCOT	$ 6,971	$ —	$ —	$ —	$ —	$ —
Retail energy charge in Northeast/ Midwest	2,139	—	—	—	—	—
Wholesale generation revenue from ISO/ RTO	—	1,105	1,209	467	950	562
Capacity revenue from ISO/ RTO (a)	—	—	20	—	56	27
Revenue from other wholesale contracts	—	696	1,106	151	150	22
Total revenue from contracts with customers	9,110	1,801	2,335	618	1,156	611
Other revenues:						
Intangible amortization	—	—	1	—	(7)	—
Hedging and other revenues (b)	345	(640)	(316)	(291)	(765)	(231)
Affiliate sales (c)	—	2,572	1,686	9	484	4
Total other revenues	345	1,932	1,371	(282)	(288)	(227)
Total revenues	$ 9,455	$ 3,733	$ 3,706	$ 336	$ 868	$ 384

(a) Represents net capacity sold (purchased) in each ISO/RTO. The East segment includes $302 million of capacity sold offset by $282 million of capacity purchased. The Sunset segment includes $59 million of capacity sold offset by $3 million of capacity purchased. The Asset Closure segment includes $27 million of capacity sold.

(b) Includes $2.163 billion of unrealized net losses from mark-to-market valuations of commodity positions.

For the year ended	Retail	Texas	East	West	Sunset	Asset Closure
December 31, 2022	(532)	(1,472)	(757)	(324)	(3)	106

(1) Amounts attributable to generation segments offset in fuel, purchased power costs and delivery fees in the Retail segment, with no impact to consolidated results.

(c) Texas and East segments include $817 million and $38 million, respectively, of affiliated unrealized net losses, and Sunset and Asset Closure segment includes $30 million and $4 million, respectively, of affiliated unrealized net gains from mark-to-market valuations of commodity positions with the Retail segment.

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	Year Ended December 31, 2021					
	Retail	Texas	East	West	Sunset	Asset Closure
Revenue from contracts with customers:						
Retail energy charge in ERCOT	$ 5,733	$ —	$ —	$ —	$ —	$ —
Retail energy charge in Northeast/ Midwest	2,255	—	—	—	—	—
Wholesale generation revenue from ISO/ RTO	—	3,808	786	229	1,050	475
Capacity revenue from ISO/ RTO (a)	—	—	(22)	1	122	62
Revenue from other wholesale contracts	—	2,302	602	104	192	1
Total revenue from contracts with customers	7,988	6,110	1,366	334	1,364	538
Other revenues:						
Intangible amortization	(2)	—	74	—	(12)	—
Hedging and other revenues (b)	(115)	(4,355)	123	35	(929)	(442)
Affiliate sales (c)	—	1,035	1,024	5	238	(18)
Total other revenues	(117)	(3,320)	1,221	40	(703)	(460)
Total revenues	$ 7,871	$ 2,790	$ 2,587	$ 374	$ 661	$ 78

(a) Represents net capacity sold (purchased) in each ISO/RTO. The East segment includes $470 million of capacity purchased offset by $448 million of capacity sold. The West segment includes $1 million of capacity sold. The Sunset segment includes $126 million of capacity sold offset by $4 million of capacity purchased. The Asset Closure segment includes $62 million of capacity sold.

(b) Includes $1.191 billion of unrealized net losses from mark-to-market valuations of commodity positions.

For the year ended	Retail	Texas	East	West	Sunset	Asset Closure
December 31, 2021	(325)	(1,272)	(637)	(42)	(394)	(240)

(1) Amounts attributable to generation segments offset in fuel, purchased power costs and delivery fees in the Retail segment, with no impact to consolidated results.

(c) Texas, East, Sunset and Asset Closure segments include $1.028 billion, $529 million, $144 million and $18 million respectively, of affiliated unrealized net losses from mark-to-market valuations of commodity positions with the Retail segment.

Retail Energy Charges

Revenue is recognized when electricity is delivered to our customers in an amount that we expect to invoice for volumes delivered or services provided. Sales tax is excluded from revenue. Payment terms vary from 15 to 60 days from invoice date. Revenue is recognized over-time using the output method based on kilowatt hours delivered. Energy charges are delivered as a series of distinct services and are accounted for as a single performance obligation.

Energy sales and services that have been delivered but not billed by period end are estimated. Accrued unbilled revenues are based on estimates of customer usage since the date of the last meter reading provided by the independent system operators or electric distribution companies. Estimated amounts are adjusted when actual usage is known and billed.

As contracts for retail electricity can be for multi-year periods, the Company has performance obligations under these contracts that have not yet been satisfied. These performance obligations have transaction prices that are both fixed and variable, and that vary based on the contract duration and customer type. For the fixed price contracts, the amount of any unsatisfied performance obligations will vary based on customer usage, which will depend on factors such as weather and customer activity and therefore it is not practicable to estimate such amounts.

Wholesale Generation Revenue from ISOs/RTOs

Revenue is recognized when volumes are delivered to the ISO/RTO. Revenue is recognized over time using the output method based on kilowatt hours delivered and cash is settled within 10 days of invoicing. Vistra operates as a market participant within ERCOT, PJM, ISO-NE, NYISO, MISO and CAISO and expects to continue to remain under contract with each ISO/RTO indefinitely. Wholesale generation revenues are delivered as a series of distinct services and are accounted for as a single performance obligation. When electricity is sold to and purchased from the same ISO/RTO in the same period, the excess of the amount sold over the amount purchased is reflected in wholesale generation revenues.

Capacity Revenue From ISO/RTO

We offer generation capacity into competitive ISO/RTO auctions in exchange for revenue from awarded capacity offers. Capacity ensures installed generation and demand response is available to satisfy system integrity and reliability requirements. Capacity revenues are recognized when the performance obligation is satisfied ratably over time as our power generation facilities stand ready to deliver power to the customer. Penalties are assessed by the ISO/RTO against generation facilities if the facility is not available during the capacity period. The penalties are recorded as a reduction to revenue.

Revenue from Other Wholesale Contracts

Other wholesale contracts include other revenue activity with the ISO/RTO, such as ancillary services, auction revenue, neutrality revenue and revenue from nonaffiliated retail electric providers, municipalities or other wholesale counterparties. Revenue is recognized when the service is performed. Revenue is recognized over time using the output method based on kilowatt hours delivered or other applicable measurements, and cash settles shortly after invoicing. Vistra operates as a market participant within ERCOT, PJM, ISO-NE, NYISO, MISO and CAISO and expects to continue to remain under contract with each ISO/RTO indefinitely. Other wholesale contracts are delivered as a series of distinct services and are accounted for as a single performance obligation.

Other Revenues

Other revenues, as included in the tables of disaggregated revenue above, represent amounts not accounted for under ASC 606, *Revenue from Contracts with Customers* and are comprised of intangible amortization, hedging and other revenues and affiliate sales.

- Intangible amortization represents amortization of acquired intangible liabilities related to retail and wholesale contracts (see Note 6).
- Some of our contracts for the sale of electricity meet the definition of a derivative under the accounting standards related to derivative instruments. Revenue from derivative contracts accounted for under ASC 815, *Derivatives and Hedging* is not considered revenue from contracts with customers under the accounting standards related to revenue. Our revenue from the sale of electricity under derivative contracts, including the impact of unrealized gains or losses on those contracts, is reported in the table above as hedging and other revenues.
- Sales to affiliates are presented by segment and eliminated in consolidation.

Contract and Other Customer Acquisition Costs

We defer costs to acquire retail contracts and amortize these costs over the expected life of the contract. The expected life of a retail contract is calculated using historical attrition rates, which we believe to be an accurate indicator of future attrition rates. The deferred acquisition and contract cost balance as of December 31, 2023 and 2022 was $97 million and $89 million, respectively. The amortization related to these costs during the years ended December 31, 2023, 2022 and 2021 totaled $88 million, $83 million and $75 million respectively, recorded as SG&A expenses, and $6 million, $6 million and $6 million, respectively, recorded as a reduction to operating revenues in the consolidated statements of operations.

Practical Expedients

The vast majority of revenues are recognized under the right to invoice practical expedient, which allows us to recognize revenue in the same amount that we have a right to invoice our customers. Unbilled revenues are recorded based on the volumes delivered and services provided to the customers at the end of the period, using the right to invoice practical expedient. We have elected to not disclose the value of unsatisfied performance obligations for contracts with variable consideration for which we recognize revenue using the right to invoice practical expedient. We use the portfolio approach in evaluating similar customer contracts with similar performance obligations. Sales taxes are not included in revenue.

Performance Obligations

As of December 31, 2023, we have future performance obligations that are unsatisfied, or partially unsatisfied, relating to capacity auction volumes awarded through capacity auctions held by the ISO/RTO or contracts with customers. Therefore, an obligation exists as of the date of the results of the respective ISO/RTO capacity auction or the contract execution date. These obligations total $480 million, $417 million, $282 million, $100 million and $62 million that will be recognized in the years ending December 31, 2024, 2025, 2026, 2027 and 2028, respectively, and $610 million thereafter. Capacity revenues are recognized as capacity is made available to the related ISOs/RTOs or counterparties.

Accounts Receivable

The following table presents trade accounts receivable (net of allowance for uncollectible accounts) relating to both ASC 606, *Revenue from Contracts with Customers* and other activities:

	December 31,	
	2023	2022
Trade accounts receivable from contracts with customers — net	$ 1,239	$ 1,644
Other trade accounts receivable — net	435	415
Total trade accounts receivable — net	$ 1,674	$ 2,059

6. GOODWILL AND IDENTIFIABLE INTANGIBLE ASSETS AND LIABILITIES

Goodwill

As of both December 31, 2023 and 2022, the carrying value of goodwill totaled $2.583 billion as there were no additions or impairments in the years then ended. The carrying value of goodwill as of each date consists of the following:

Reportable Segment	Reporting Unit	Carrying Value of Goodwill
Texas	Texas Generation	$ 122
Retail (a)	Retail	2,461
Total		$ 2,583

(a) $1.944 billion of goodwill is deductible for tax purposes over 15 years on a straight-line basis.

Goodwill is required to be evaluated for impairment at least annually or whenever events or changes in circumstances indicate an impairment may exist. We have selected October 1 as our annual goodwill test date. On the most recent goodwill testing date, we applied qualitative factors and determined that it was more likely than not that the fair value of our Retail and Texas Generation reporting units exceeded their carrying value at October 1, 2023. Significant qualitative factors evaluated included reporting unit financial performance and market multiples, general macroeconomic, industry, and market conditions, cost factors, customer attrition, interest rates and changes in reporting unit book value.

Identifiable Intangible Assets and Liabilities

Identifiable intangible assets are comprised of the following:

	December 31, 2023			December 31, 2022	
Identifiable Intangible Asset	Gross Carrying Amount	Accumulated Amortization	Net	Gross Carrying Amount	Accumulated Amortization
Retail customer relationship	$ 2,088	$ 1,866	$ 222	$ 2,088	$ 1,768
Software and other technology-related assets	536	315	221	475	258
Retail and wholesale contracts	233	217	16	233	209
LTSA	18	5	13	18	4
Other identifiable intangible assets (a)	62	11	51	50	8
Total identifiable intangible assets subject to amortization	$ 2,937	$ 2,414	523	$ 2,864	$ 2,247
Retail trade names (not subject to amortization)			1,341		
Total identifiable intangible assets			$ 1,864		

(a) Includes mining development costs and environmental allowances (emissions allowances and renewable energy certificates).

Identifiable intangible liabilities are comprised of the following:

	Year Ended December 31,	
Identifiable Intangible Liability	2023	2022
LTSA	$ 122	$ 128
Fuel and transportation purchase contracts	9	9
Other identifiable liabilities	—	3
Total identifiable intangible liabilities	$ 131	$ 140

Expense related to finite-lived identifiable intangible assets (including the classification in the consolidated statements of operations) consisted of:

Identifiable Intangible Assets	Consolidated Statements of Operations	Remaining useful lives of identifiable intangible assets at December 31, 2023 (weighted average in years)	Year Ended December 31, 2023	2022	2021
Retail customer relationship	Depreciation and amortization	3	$ 98	$ 137	$ 197
Software and other technology-related assets	Depreciation and amortization	4	58	69	74
Retail and wholesale contracts	Operating revenues/fuel, purchased power costs and delivery fees	3	8	7	(56)
Other identifiable intangible assets	Fuel, purchased power costs and delivery fees	5	357	391	279
Total intangible asset expense (a)			$ 521	$ 604	$ 494

(a) Amounts recorded in depreciation and amortization totaled $158 million, $208 million and $275 million for the years ended December 31, 2023, 2022 and 2021, respectively. Amounts include all expenses associated with environmental allowances including expenses accrued to comply with emissions allowance programs and renewable portfolio standards which are presented in fuel, purchased power costs and delivery fees on our consolidated statements of operations. Emissions allowance obligations are accrued as associated electricity is generated and renewable energy certificate obligations are accrued as retail electricity delivery occurs.

The following is a description of the separately identifiable intangible assets. In connection with fresh start reporting, the Dynegy Merger, the Crius Transaction and the Ambit Transaction, the intangible assets were adjusted based on their estimated fair value as of the Effective Date, the Dynegy Merger Date, the Crius Acquisition Date and the Ambit Acquisition Date, respectively, based on observable prices or estimates of fair value using valuation models.

- *Retail customer relationship* — Retail customer relationship intangible asset represents the fair value of our non-contracted retail customer base, including residential and business customers, and is being amortized using an accelerated method based on historical customer attrition rates and reflecting the expected pattern in which economic benefits are realized over their estimated useful life.

- *Retail and wholesale contracts* — These intangible assets represent the value of various acquired retail and wholesale contracts and fuel and transportation purchase contracts. The contracts were identified as either assets or liabilities based on the respective fair values as of the Effective Date, the Dynegy Merger Date, the Crius Acquisition Date or the Ambit Acquisition Date utilizing prevailing market prices for commodities or services compared to the fixed prices contained in these agreements. The intangible assets or liabilities are being amortized in relation to the economic terms of the related contracts.

- *LTSA* — Our acquired LTSA represent the estimated fair value of favorable or unfavorable contract obligations with respect to long-term plant maintenance agreements and are being amortized based on the expected usage of the service agreements over the contract terms. The majority of the plant maintenance services relate to capital improvements and the related amortization of the plant maintenance agreements is recorded to property, plant and equipment.

- *Retail trade names* — Our retail trade name intangible assets represent the fair value of our retail brands, including the trade names of TXU Energy™, Ambit Energy, 4Change Energy™, Homefield Energy, Dynegy Energy Services, TriEagle Energy, Public Power and U.S. Gas & Electric, and were determined to be indefinite-lived assets not subject to amortization. These intangible assets are evaluated for impairment at least annually in accordance with accounting guidance related to other indefinite-lived intangible assets. We have selected October 1 as our test date. Significant qualitative factors evaluated included trade name financial performance, general macroeconomic, industry, and market conditions, customer attrition and interest rates. On the most recent testing date, we determined that it was more likely than not that the fair value of our retail trade name intangible asset exceeded its carrying value at October 1, 2023.

Estimated Amortization of Identifiable Intangible Assets

As of December 31, 2023, the estimated aggregate amortization expense of identifiable intangible assets for each of the next five fiscal years is as shown below.

Year	Estimated Amortization Expense
2024	$ 122
2025	$ 95
2026	$ 71
2027	$ 47
2028	$ 31

7. INCOME TAXES

Vistra files a U.S. federal income tax return that includes the results of its consolidated subsidiaries. Vistra is the corporate parent of the Vistra consolidated group. Pursuant to applicable U.S. Department of the Treasury regulations and published guidance of the IRS, corporations that are members of a consolidated group have joint and several liability for the taxes of such group.

Income Tax Expense (Benefit)

The components of our income tax expense (benefit) are as follows:

	Year Ended December 31,		
	2023	2022	2021
Current:			
U.S. Federal	$ (1)	$ 2	$ 1
State	52	7	16
Total current	51	9	17
Deferred:			
U.S. Federal	421	(304)	(336)
State	36	(55)	(139)
Total deferred	457	(359)	(475)
Total	$ 508	$ (350)	$ (458)

Reconciliation of income taxes computed at the U.S. federal statutory rate to income tax expense (benefit) recorded:

	Year Ended December 31,		
	2023	2022	2021
Income (loss) before income taxes	$ 2,000	$ (1,560)	$ (1,722)
U.S. federal statutory rate	21 %	21 %	21 %
Income taxes at the U.S. federal statutory rate	420	(328)	(362)
Nondeductible TRA accretion	41	18	(8)
State tax, net of federal benefit	86	(19)	(2)
Valuation allowance on state NOLs	(20)	(8)	(94)
Release of Uncertain Tax Positions	(35)	—	—
Other	16	(13)	8
Income tax expense (benefit)	$ 508	$ (350)	$ (458)
Effective tax rate	25.4 %	22.4 %	26.6 %

Deferred Income Tax Balances

Deferred income taxes provided for temporary differences based on tax laws in effect at December 31, 2023 and 2022 are as follows:

	December 31,	
	2023	2022
Noncurrent Deferred Income Tax Assets		
Tax credit carryforwards	$ 84	$ 125
Loss carryforwards	1,081	1,182
Identifiable intangible assets	380	456
Long-term debt	173	121
Employee benefit obligations	117	108
Commodity contracts and interest rate swaps	664	764
Other	33	49
Total deferred tax assets	$ 2,532	$ 2,805
Noncurrent Deferred Income Tax Liabilities		
Property, plant and equipment	1,264	1,033
Total deferred tax liabilities	1,264	1,033
Valuation allowance	46	63
Net Deferred Income Tax Asset	$ 1,222	$ 1,709

As of December 31, 2023, we had total net deferred tax assets of approximately $1.22 billion that were substantially comprised of book and tax basis differences related to our generation and mining property, plant and equipment, as well as federal and state net operating loss (NOL) carryforwards. Our deferred tax assets were significantly impacted by the impacts of Winter Storm Uri as well as the Dynegy Merger. For the year ended December 31, 2023, we recognized a tax benefit of $20 million on the release of state valuation allowances. For the year ended December 31, 2022, we recognized a tax benefit of $9 million on the release of state valuation allowances. For the year ended December 31, 2021, we recognized a tax benefit of $74 million on the release of state valuation allowances largely related to Illinois. As of December 31, 2023, we assessed the need for a valuation allowance related to our deferred tax asset and considered both positive and negative evidence related to the likelihood of realization of the deferred tax assets. We have identified negative evidence, in the form of cumulative losses on an unadjusted basis over the preceding 12 quarters. We evaluated historical earnings after adjusting for certain nonrecurring items for purposes of projecting future income, performed scheduling of the reversal of temporary differences, and considered other positive and negative evidence. In connection with our analysis, we concluded that it is more likely than not that the federal deferred tax assets will be fully utilized by future taxable income, and thus no valuation allowance was required. A valuation allowance of approximately $3 million was recorded in the fourth quarter of 2022 against a portion of our charitable contribution deferred tax asset that is not more likely than not to be utilized before expiration in 2024.

As of December 31, 2023, we had $4.0 billion pre-tax net operating loss (NOL) carryforwards for federal income tax purposes that will begin to expire in 2032.

The income tax effects of the components included in accumulated other comprehensive income totaled net deferred tax liabilities of zero and $7 million at December 31, 2023 and 2022, respectively.

Inflation Reduction Act of 2022 (IRA)

In August 2022, the U.S. enacted the IRA, which, among other things, implements substantial new and modified energy tax credits, including a nuclear PTC, a solar PTC, a first-time stand-alone battery storage investment tax credit, a 15% corporate alternative minimum tax (CAMT) on book income of certain large corporations, and a 1% excise tax on net stock repurchases. Treasury regulations are expected to further define the scope of the legislation in many important respects over the next twelve months. The excise tax on stock repurchases is not expected to have a material impact on our financial statements. Vistra is not subject to the CAMT in the 2023 tax year since it applies only to corporations that have a three-year average annual adjusted financial statement income in excess of $1 billion. We have taken the CAMT and relevant extensions or expansions of existing tax credits applicable to projects in our immediate development pipeline into account when forecasting cash taxes for periods after the law takes effect. See Note 1 for our accounting policy related to refundable and transferable PTCs and ITCs.

Final Section 163(j) Regulations

The final Section 163(j) regulations were issued in July 2020 and provided a critical correction to the proposed regulations with respect to the computation of adjusted taxable income. As of January 1, 2022, certain provisions in the final Section 163(j) regulations have sunset, including the addback of depreciation and amortization to adjusted taxable income. As a result, under the law as currently enacted, Vistra's deductible business interest expense has been significantly limited for the 2023 tax year. Vistra remains active in legislative monitoring and advocacy efforts to support a legislative solution to reinstate and make permanent the addback of depreciation and amortization to adjusted taxable income.

Liability for Uncertain Tax Positions

Accounting guidance related to uncertain tax positions requires that all tax positions subject to uncertainty be reviewed and assessed with recognition and measurement of the tax benefit based on a "more-likely-than-not" standard with respect to the ultimate outcome, regardless of whether this assessment is favorable or unfavorable.

We classify interest and penalties related to uncertain tax positions as current income tax expense. The amounts were immaterial for the years ended December 31, 2023, 2022 and 2021. The following table summarizes the changes to the uncertain tax positions, reported in accumulated deferred income taxes and other current liabilities in the consolidated balance sheets for the years ended December 31, 2023, 2022 and 2021.

	Year Ended December 31,		
	2023	2022	2021
Balance at beginning of period, excluding interest and penalties	$ 36	$ 38	$ 39
Additions based on tax positions related to prior years	—	—	1
Reductions based on tax positions related to prior years	—	(1)	—
Reductions related to the lapse of the tax statute of limitations	(35)	—	—
Settlements with taxing authorities	(1)	(1)	(2)
Balance at end of period, excluding interest and penalties	$ —	$ 36	$ 38

Vistra and its subsidiaries file income tax returns in U.S. federal, state and foreign jurisdictions and are, at times, subject to examinations by the IRS and other taxing authorities. In February 2021, Vistra was notified that the IRS had opened a federal income tax audit for tax years 2018 and 2019. The federal income tax audit was closed in June 2023 with immaterial changes. Uncertain tax positions totaled zero and $36 million as of December 31, 2023 and 2022, respectively. Of the amounts recorded as unrecognized tax benefits, an insignificant portion would impact our effective tax rate if recognized.

Tax Matters Agreement

On the Effective Date, we entered into the Tax Matters Agreement with EFH Corp. whereby the parties have agreed to take certain actions and refrain from taking certain actions in order to preserve the intended tax treatment of the Spin-Off and to indemnify the other parties to the extent a breach of such agreement results in additional taxes to the other parties.

Among other things, the Tax Matters Agreement allocates the responsibility for taxes for periods prior to the Spin-Off between EFH Corp. and us. For periods prior to the Spin-Off: (a) Vistra is generally required to reimburse EFH Corp. with respect to any taxes paid by EFH Corp. that are attributable to us and (b) EFH Corp. is generally required to reimburse us with respect to any taxes paid by us that are attributable to EFH Corp.

We are also required to indemnify EFH Corp. against taxes, under certain circumstance, if the IRS or another taxing authority successfully challenges the amount of gain relating to the PrefCo Preferred Stock Sale or the amount or allowance of EFH Corp.'s net operating loss deductions.

Subject to certain exceptions, the Tax Matters Agreement prohibits us from taking certain actions that could reasonably be expected to undermine the intended tax treatment of the Spin-Off or to jeopardize the conclusions of the private letter ruling we obtained from the IRS or opinions of counsel received by us or EFH Corp., in each case, in connection with the Spin-Off. Certain of these restrictions apply for two years after the Spin-Off.

Under the Tax Matters Agreement, we may engage in an otherwise restricted action if (a) we obtain written consent from EFH Corp., (b) such action or transaction is described in or otherwise consistent with the facts in the private letter ruling we obtained from the IRS in connection with the Spin-Off, (c) we obtain a supplemental private letter ruling from the IRS, or (d) we obtain an unqualified opinion of a nationally recognized law or accounting firm that is reasonably acceptable to EFH Corp. that the action will not affect the intended tax treatment of the Spin-Off.

8. TAX RECEIVABLE AGREEMENT OBLIGATION

On the Effective Date, Vistra entered into the TRA with a transfer agent on behalf of certain former first-lien creditors of TCEH. The TRA generally provides for the payment by us to holders of TRA Rights of 85% of the amount of cash savings, if any, in U.S. federal and state income tax that we realize in periods after Emergence as a result of (a) certain transactions consummated pursuant to the Plan of Reorganization (including the step-up in tax basis in our assets resulting from the PrefCo Preferred Stock Sale), (b) the tax basis of all assets acquired in connection with the acquisition of two CCGT natural gas-fueled generation facilities in April 2016 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.

Pursuant to the TRA, we issued TRA Rights for the benefit of the first-lien secured creditors of TCEH entitled to receive such TRA Rights under the Plan of Reorganization. Such TRA Rights are entitled to certain registration rights more fully described in the Registration Rights Agreement (see Note 20). As of January 1, 2023, 426,369,370 of TRA Rights were outstanding.

In December 2023, Vistra repurchased (Repurchase) approximately 74% of the TRA Rights to receive payments under the TRA from a select group of registered holders of the TRA Rights (Selling Holders) in exchange for consideration of $1.50 per repurchased TRA Right, totaling an aggregate purchase price for the Repurchase of approximately $476 million. The consideration for the Repurchase was paid through the issuance of 476,081 shares of Series C Preferred Stock (see Note 15) to the Selling Holders in a transaction exempt from registration pursuant to Section 4(a)(2) of the Securities Act. As part of the transaction, the Company agreed to file a shelf registration statement on Form S-3 registering the resale of the shares by the Selling Holders of Series C Preferred Stock from time to time under Rule 415 of the Securities Act, which was filed on January 29, 2024. If the Company repurchases TRA Rights at any time during the 180 days following December 29, 2023 at a price per TRA Right greater than $1.50, the Company will pay the Selling Holders an amount equal to such excess purchase price per TRA Right sold by the Selling Holders.

In connection with the Repurchase, holders of approximately 74% of the outstanding TRA Rights consented to certain amendments to the TRA which were effected in an Amended and Restated Tax Receivables Agreement (A&R TRA), dated as of December 29, 2023. Such amendments to the TRA include (i) the removal of the Company's obligation to provide registered holders of the TRA Rights (Holders) with regular reporting and access to information, (ii) limitations on the transferability of the TRA Rights, (iii) removal of certain obligations of the Company in the event it incurs indebtedness and (iv) a change to the definition of "Change of Control."

In connection with the Repurchase, in the year ended December 31, 2023, we recognized a $29 million gain in other income in our consolidated statements of operations. The gain represents the difference between the $506 million carrying value of the portion of the TRA liability that was repurchased and the $476 million fair value of the Series C Preferred Stock issued.

On January 11, 2024, Vistra repurchased an additional 43,494,944 of outstanding TRA Rights from a select group of registered holders of TRA Rights in exchange for consideration of $1.50 per repurchased TRA Right. Total consideration of $65 million was paid using cash on hand.

On January 31, 2024, Vistra announced a cash tender offer to purchase any and all outstanding TRA Rights in exchange for consideration of $1.50 per tendered TRA Right accepted for purchase prior to close of business on February 13, 2024 (Early Tender Date), which included an early tender premium of $0.05 per TRA Right accepted for purchase. As of the Early Tender Date, 55,056,931 TRA Rights were accepted for purchase for total consideration of $83 million, which was paid using cash on hand. TRA Rights accepted for purchase after the Early Tender Date, but prior to close of business on February 28, 2024, will receive consideration of $1.45 per TRA Right accepted for purchase, which will be paid using cash on hand.

As of the Early Tender Date, we have repurchased an aggregate 98% of the original outstanding TRA Rights, of which 10,430,083 TRA Rights remain outstanding.

The following table summarizes the changes to the TRA obligation, reported as other current liabilities and Tax Receivable Agreement obligation in our consolidated balance sheets, for the years ended December 31, 2023, 2022 and 2021.

	Year Ended December 31,		
	2023	2022	2021
TRA obligation at the beginning of the period	$ 522	$ 395	$ 450
Accretion expense	82	64	62
Changes in tax assumptions impacting timing of payments (a)	82	64	(115)
Impacts of Tax Receivable Agreement	164	128	(53)
Payments	(9)	(1)	(2)
Repurchase of TRA Rights	(506)	—	—
TRA obligation at the end of the period	171	522	395
Less amounts due currently	(7)	(8)	(1)
Noncurrent TRA obligation at the end of the period	$ 164	$ 514	$ 394

(a) During the year ended December 31, 2023, we recorded an increase to the carrying value of the TRA obligation totaling $82 million as a result of adjustments to forecasted taxable income due to increases in longer-term commodity price forecasts. During the year ended December 31, 2022, we recorded an increase to the carrying value of the TRA obligation totaling approximately $64 million as a result of adjustments to forecasted book and taxable income due to increases in commodity price forecasts. During the year ended December 31, 2021, we recorded a decrease to the carrying value of the TRA obligation totaling $115 million as a result of adjustments to forecasted taxable income, including the financial impacts of Winter Storm Uri, and anticipated tax benefits available under current tax laws for planned additional renewable development projects.

As of December 31, 2023, the estimated carrying value of the TRA obligation totaled $171 million, which represents the discounted amount of projected payments under the TRA. The projected payments are based on certain assumptions, including but not limited to (a) the federal corporate income tax rate of 21%, (b) estimates of our taxable income in the current and future years and (c) additional states that Vistra now operates in, including the relevant tax rate and apportionment factor for each state. Our taxable income takes into consideration the current federal tax code, various relevant state tax laws and reflects our current estimates of future results of the business. The estimates of future business results include assumptions related to renewable development projects that Vistra is planning to execute that generate significant tax benefits. These benefits have a material impact on the timing of TRA obligation payments. These assumptions are subject to change, and those changes could have a material impact on the carrying value of the TRA obligation. As of December 31, 2023, and excluding the January and February 2024 activity discussed above, the aggregate amount of undiscounted federal and state payments under the TRA is estimated to be approximately $350 million, with more than half of such amount expected to be paid during the next 15 years, and the final payment expected to be made around the year 2056 (if the TRA is not terminated earlier pursuant to its terms).

The carrying value of the obligation is being accreted to the amount of the gross expected obligation using the effective interest method. Changes in the amount of this obligation resulting from changes to either the timing or amount of TRA payments are recognized in the period of change and measured using the discount rate inherent in the initial fair value of the obligation.

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 three-month CME Term SOFR plus the tenor spread adjustment of 0.26161% plus 100 basis points) of the anticipated future tax benefits based on certain valuation assumptions.

The LIBOR provisions of the TRA are subject to the Adjustable Interest Rate (LIBOR) Act of 2022 (LIBOR Act) and the regulations promulgated to carry out the LIBOR Act (LIBOR Regulations). With respect to payments under the TRA, pursuant to the LIBOR Act and the LIBOR Regulations, the "Board-selected benchmark replacement" (BSBR) of three-month CME Term SOFR plus the tenor spread adjustment of 0.26161% automatically became the benchmark replacement to three-month LIBOR on

July 1, 2023 and, in addition, the four conforming changes promulgated by the Federal Reserve System Board in the LIBOR Regulations (each of which is a technical or administrative in nature) also apply to the TRA, by operation of law, to effectuate the implementation and use of the foregoing BSBR.

9. EARNINGS PER SHARE

Basic earnings per share available to common stockholders are based on the weighted average number of common shares outstanding during the period. Diluted earnings per share is calculated using the treasury stock method and includes the effect of all potential issuances of common shares under stock-based incentive compensation arrangements. Cumulative dividends attributable to Series C Preferred Stock were immaterial during the year ended December 31, 2023.

	Year Ended December 31,		
	2023	2022	2021
Net income (loss) attributable to Vistra	$ 1,493	$ (1,227)	$ (1,274)
Less cumulative dividends attributable to Series A Preferred Stock	(80)	(80)	(17)
Less cumulative dividends attributable to Series B Preferred Stock	(70)	(70)	(4)
Less cumulative dividends attributable to Series C Preferred Stock	—	—	—
Net income (loss) attributable to common stock — basic	1,343	(1,377)	(1,295)
Weighted average shares of common stock outstanding — basic	369,771,359	422,447,074	482,214,544
Net income (loss) per weighted average share of common stock outstanding — basic	$ 3.63	$ (3.26)	$ (2.69)
Dilutive securities: Stock-based incentive compensation plan	5,421,752	—	—
Weighted average shares of common stock outstanding — diluted	375,193,110	422,447,074	482,214,544
Net income (loss) per weighted average share of common stock outstanding — diluted	$ 3.58	$ (3.26)	$ (2.69)

Stock-based incentive compensation plan awards excluded from the calculation of diluted earnings per share because the effect would have been antidilutive totaled 392,218, 8,292,647 and 14,412,299 shares for the years ended December 31, 2023, 2022 and 2021, respectively.

10. ACCOUNTS RECEIVABLE FINANCING

Accounts Receivable Securitization Program

TXU Energy Receivables Company LLC (RecCo), an indirect subsidiary of Vistra, has an accounts receivable financing facility (Receivables Facility) provided by issuers of asset-backed commercial paper and commercial banks (Purchasers). The Receivables Facility was renewed in July 2023, extending the term of the Receivables Facility to July 2024 and adjusting the commitment of the purchasers to purchase interests in the receivables under the Receivables Facility during all periods to a fixed purchase limit of $750 million from seasonally adjusted commitment limits ranging from $600 million to $750 million.

In connection with the Receivables Facility, TXU Energy, Dynegy Energy Services, Ambit Texas, Value Based Brands and TriEagle Energy, each indirect subsidiaries of Vistra and originators under the Receivables Facility (Originators), each sell and/or contribute, subject to certain exclusions, all of its receivables (other than any receivables excluded pursuant to the terms of the Receivables Facility), arising from the sale of electricity to its customers and related rights (Receivables), to RecCo, a consolidated, wholly owned, bankruptcy-remote, direct subsidiary of TXU Energy. RecCo, in turn, is subject to certain conditions, and may draw under the Receivables Facility up to the limits described above to fund its acquisition of the Receivables from the Originators. RecCo has granted a security interest on the Receivables and all related assets for the benefit of the Purchasers under the Receivables Facility and Vistra Operations has agreed to guarantee the obligations under the agreements governing the Receivables Facility. Amounts funded by the Purchasers to RecCo are reflected as short-term borrowings on the consolidated balance sheets. Proceeds and repayments under the Receivables Facility are reflected as cash flows from financing activities in our consolidated statements of cash flows. Receivables transferred to the Purchasers remain on Vistra's balance sheet and Vistra reflects a liability equal to the amount advanced by the Purchasers. The Company records interest expense on amounts advanced. TXU Energy continues to service, administer and collect the Receivables on behalf of RecCo and the Purchasers, as applicable.

As of December 31, 2023, there were no outstanding borrowings under the Receivables Facility. As of December 31, 2022, outstanding borrowings under the Receivables totaled $425 million and were supported by $1 billion of RecCo gross receivables.

Repurchase Facility

TXU Energy and the other originators under the Receivables Facility have a repurchase facility (Repurchase Facility) that is provided on an uncommitted basis by a commercial bank as buyer (Buyer). In July 2023, the Repurchase Facility was renewed until July 2024 while maintaining the facility size of $125 million. The Repurchase Facility is collateralized by a subordinated note (Subordinated Note) issued by RecCo in favor of TXU Energy for the benefit of Originators under the Receivables Facility and representing a portion of the outstanding balance of the purchase price paid for the Receivables sold by the Originators to RecCo under the Receivables Facility. Under the Repurchase Facility, TXU Energy may request that Buyer transfer funds to TXU Energy in exchange for a transfer of the Subordinated Note, with a simultaneous agreement by TXU Energy to transfer funds to Buyer at a date certain or on demand in exchange for the return of the Subordinated Note (collectively, the Repo Transaction). Each Repo Transaction is expected to have a term of one month, unless terminated earlier on demand by TXU Energy or terminated by Buyer after an event of default.

TXU Energy and the other Originators have each granted Buyer a first-priority security interest in the Subordinated Note to secure its obligations under the agreements governing the Repurchase Facility, and Vistra Operations has agreed to guarantee the obligations under the agreements governing the Repurchase Facility. Unless earlier terminated under the agreements governing the Repurchase Facility, the Repurchase Facility will terminate concurrently with the scheduled termination of the Receivables Facility.

There were no outstanding borrowings under the Repurchase Facility as of both December 31, 2023 and December 31, 2022.

11. COLLATERAL FINANCING AGREEMENT WITH AFFILIATE

On June 15, 2023, Vistra Operations entered into a facility agreement (Facility Agreement) with a Delaware trust formed by the Company (the Trust) that sold 450,000 pre-capitalized trust securities (P-Caps) redeemable May 17, 2028 for an initial purchase price of $450 million. The Trust is not consolidated by Vistra. The Trust invested the proceeds from the sale of the P-Caps in a portfolio of either (a) U.S. Treasury securities (Treasuries) or (b) Treasuries and/or principal and interest strips of Treasuries (Treasury Strips, and together with the Treasuries and cash denominated in U.S. dollars, the Eligible Assets). At the direction of Vistra Operations, the Eligible Assets held by the Trust can be (i) delivered to one or more designated subsidiaries of Vistra Operations in order to allow such subsidiaries to use the Eligible Assets to meet certain posting obligations with counterparties, and/or (ii) pledged as collateral support for a letter of credit program. Fees related to the Facility Agreement transaction totaled $7 million in the year ended December 31, 2023, which were capitalized as other noncurrent assets.

Under the Facility Agreement, Vistra Operations has the right (Issuance Right), from time to time, to require the Trust to purchase from Vistra Operations up to $450 million aggregate principal amount of Vistra Operations' 7.233% Senior Secured Notes due 2028 (7.233% Senior Secured Notes) in exchange for the delivery of all or a portion of the Treasuries and Treasury Strips corresponding to the portion of the issuance right exercised at such time.

The Trust will terminate at any time prior to May 17, 2028 and distribute the 7.233% Senior Secured Notes to the holders of the P-Caps if its sole assets consist of 7.233% Senior Secured Notes that Vistra Operations is no longer entitled to repurchase.

Vistra Operations pays a facility fee (Facility Fee) to the Trust payable on each May 17 and November 17, commencing on November 17, 2023, to and including May 17, 2028 (each, a Distribution Date), and on certain other dates as provided in the Facility Agreement. The Facility Fee is generally calculated at a rate of 3.3608% per annum, applied to the maximum amount of 7.233% Senior Secured Notes that Vistra Operations could issue and sell to the Trust under the Facility Agreement as of the close of business on the business day immediately preceding the applicable Distribution Date.

As of December 31, 2023, $439 million is the fair value of Eligible Assets held by counterparties to satisfy current and future margin deposit requirements and is reported in our consolidated balance sheets as margin deposits posted under affiliate financing agreement and margin deposit financing with affiliate.

12. DEBT

Amounts in the table below represent the categories of long-term debt obligations, including amounts due currently, incurred by the Company.

	December 31, 2023	December 31, 2022
Vistra Operations Credit Facilities, Term Loan B-3 Facility due December 20, 2030	$ 2,500	$ 2,514
Vistra Operations Senior Secured Notes:		
4.875% Senior Secured Notes, due May 13, 2024	400	400
3.550% Senior Secured Notes, due July 15, 2024	1,500	1,500
5.125% Senior Secured Notes, due May 13, 2025	1,100	1,100
3.700% Senior Secured Notes, due January 30, 2027	800	800
4.300% Senior Secured Notes, due July 15, 2029	800	800
6.950% Senior Secured Notes, due October 15, 2033	1,050	—
Total Vistra Operations Senior Secured Notes	5,650	4,600
Vistra Operations Senior Unsecured Notes:		
5.500% Senior Unsecured Notes, due September 1, 2026	1,000	1,000
5.625% Senior Unsecured Notes, due February 15, 2027	1,300	1,300
5.000% Senior Unsecured Notes, due July 31, 2027	1,300	1,300
4.375% Senior Unsecured Notes, due May 15, 2029	1,250	1,250
7.750% Senior Unsecured Notes, due October 15, 2031	1,450	—
Total Vistra Operations Senior Unsecured Notes	6,300	4,850
Other:		
Equipment Financing Agreements	67	79
Total other long-term debt	67	79
Unamortized debt premiums, discounts and issuance costs	(115)	(72)
Total long-term debt including amounts due currently	14,402	11,971
Less amounts due currently (a)	(2,286)	(38)
Total long-term debt less amounts due currently	$ 12,116	$ 11,933

(a) Includes $356 million of the 5.125% senior secured notes due 2025 repurchased for cash as part of the Senior Secured Notes Tender Offer in January 2024 (described below) as the payment was made with current assets on our consolidated balance sheet as of December 31, 2023.

As of December 31, 2023 and 2022, outstanding short-term borrowings under the Revolving Credit Facility and the Commodity-Linked Facility (each described below) totaled zero and $650 million, respectively.

Vistra Operations Credit Facilities and Commodity-Linked Revolving Credit Facility

Vistra Operations Credit Facilities

As of December 31, 2023, the Vistra Operations Credit Facilities consisted of up to $5.675 billion in senior secured, first-lien revolving credit commitments and outstanding term loans, which consisted of revolving credit commitments of up to $3.175 billion (Revolving Credit Facility) and term loans of $2.5 billion (Term Loan B-3 Facility). These amounts reflect the following transactions and amendments completed in 2023, 2022 and 2021:

- On December 20, 2023, Vistra Operations entered into an amendment (December 2023 Credit Agreement Amendment) to the Vistra Operations Credit Agreement among Vistra Operations, as borrower, Vistra Intermediate, the guarantors party thereto, the 2023 Incremental Term Loan Lender, Credit Suisse AG, Cayman Islands Branch, as administrative agent and collateral agent, and other parties named therein. Pursuant to the December 2023 Credit Agreement Amendment, (i) incremental term loans totaling $7 million aggregate principal amount were established and were added to (and made part of) the existing Term Loan B-3 Facility, (ii) the maturity date of the Term Loan B-3 Facility was extended to December 20, 2030, (iii) Credit Suisse AG, Cayman Islands Branch provided notice of its intent to resign as administrative agent, collateral agent and a letter of credit issuer and Vistra Operations and the required lenders agreed to appoint Citibank, N.A. as successor thereto upon the effectiveness of such resignation, (iv) interest rate margins on the Term SOFR Rate and Alternate Base Rate (ABR) were increased by 25 basis points, and (v) the credit spread adjustment related to the Adjusted Term SOFR Rate applicable to the Term B-3 Facility, as discussed in the April 2023 Credit Agreement Amendment below, was eliminated. Fees and expenses related to the December 2023 Credit Agreement Amendment of $19 million and original issue discount of $25 million were capitalized as a reduction in the carrying amount of the debt. We recorded an extinguishment gain of $3 million related to the December 2023 Credit Agreement Amendment in interest expense and other charges in our consolidated statements of operations.

- On September 26, 2023, Vistra Operations entered into (a) an amendment to the Vistra Operations Credit Agreement, among Vistra Operations, as borrower, Vistra Intermediate, the guarantors party thereto, Credit Suisse AG, Cayman Islands Branch, as administrative agent, and the other parties named therein, and (b) an amendment to the Vistra Operations Commodity-Linked Credit Agreement, among Vistra Operations, as borrower, Vistra Intermediate, the guarantors party thereto, Citibank, N.A., as administrative agent, and the other parties named therein (such amendments, the September 2023 Amendments). The September 2023 Amendments, among other things, (i) implemented changes to certain covenants and other provisions of the Vistra Operations Credit Agreement and the Vistra Operations Commodity-Linked Credit Agreement, as applicable, to allow for the Energy Harbor acquisition and related additional financings contemplated by the Commitment Letter and (ii) provided for additional operational flexibility in the conduct of Vistra Operation's business. In addition, the September 2023 amendment to the Vistra Operations Commodity-Linked Credit Agreement also provided Vistra Operations the flexibility to update the deemed hedge portfolio that serves as the borrowing base under the Commodity-Linked Facility on a more frequent basis.

- On April 28, 2023, Vistra Operations entered into an amendment (April 2023 Credit Agreement Amendment) to the Vistra Operations Credit Agreement, among Vistra Operations, as borrower, Vistra Intermediate, the guarantors party thereto, Credit Suisse AG, Cayman Islands Branch, as administrative agent, and the other parties named therein. Pursuant to the April 2023 Credit Agreement Amendment, and in light of a public statement by the supervisor for the administrator of the "LIBOR Rate" identifying June 30, 2023 as the date after which the "LIBOR Rate" was to permanently or indefinitely cease to be published, the "LIBOR Rate", with respect to the term loans under the Vistra Operations Credit Agreement, ceased to be applicable after June 30, 2023 and was replaced by the Adjusted Term SOFR Rate, other than as expressly contemplated by the April 2023 Credit Agreement Amendment. The Adjusted Term SOFR Rate with respect to the Term Loan B-3 Facility was effective through December 20, 2023 and was the interest rate per annum equal to the Term SOFR Rate plus (a) with respect to an interest period of one month, 0.11% per annum, (b) with respect to an interest period of three months, 0.26% per annum and (c) with respect to an interest period of six months, 0.43% per annum.

- On April 29, 2022 (April 2022 Amendment Effective Date) and July 18, 2022 (July 2022 Amendment Effective Date), Vistra Operations entered into amendments (2022 Credit Agreement Amendments) to the Vistra Operations Credit Agreement, among Vistra Operations, as borrower, Vistra Intermediate, the guarantors party thereto, Credit Suisse AG, Cayman Islands Branch, as administrative agent and collateral agent, and the other parties named therein. Pursuant to the 2022 Credit Agreement Amendments, new classes of extended revolving credit commitments maturing in April 2027 were established in aggregate amounts of $2.8 billion and $725 million as of the April 2022 Amendment Effective Date and the July 2022 Amendment Effective Date, respectively. The July 18, 2022 amendment to the Vistra Operations Credit Agreement also provided that Vistra Operations would terminate at least $350 million in Extended Revolving Credit Facility (as defined below) commitments by December 30, 2022 or earlier if Vistra Operations or any guarantor receives proceeds from any capital markets transaction whose primary purpose is designed to enhance the liquidity of Vistra Operations and its guarantors. In accordance with this requirement, effective December 30, 2022, Vistra Operations terminated $350 million in revolving commitments. After giving effect to the 2022 Credit Agreement Amendments and the revolving commitment reduction, the aggregate amount of revolving commitments maturing on April 29, 2027 equals $3.175 billion (Extended Revolving Credit Facility), while the $200 million in revolving commitments that matured on June 14, 2023 (Non-Extended Revolving Credit Facility) remained unchanged by the Credit Agreement Amendments. Furthermore, the 2022 Credit Agreement Amendments appointed new revolving letter of credit issuers, such that the aggregate amount of revolving letter of credit commitments equals $3.105 billion after giving effect to (i) the 2022 Credit Agreement Amendments and (ii) the maturity of the Non-Extended Credit Facility on June 14, 2023 in accordance with the terms of the Vistra Operations Credit Agreement. Fees and expenses related to the 2022 Credit Agreement Amendments totaled $8 million in the year ended December 31, 2022, which were capitalized as a reduction in the carrying amount of the debt.

- In March 2021, Vistra Operations borrowed $1.0 billion principal amount under the Term Loan A Facility. In April 2021, Vistra Operations borrowed an additional $250 million principal amount under the Term Loan A Facility. Proceeds from the Term Loan A Facility, together with cash on hand, were used to repay certain amounts outstanding under the Revolving Credit Facility. Borrowings under the Term Loan A Facility were reported in short-term borrowings in our consolidated balance sheet. In May 2021, Vistra Operations used the proceeds from the issuance of the Vistra Operations 4.375% senior unsecured notes due 2029 (described below), together with cash on hand, to repay the $1.25 billion borrowings under the Term Loan A Facility. We recorded an extinguishment loss of $1 million on the transaction in the year ended December 31, 2021.

Our credit facilities and related available capacity at December 31, 2023 are presented below.

		December 31, 2023			
Credit Facilities	Maturity Date	Facility Limit	Cash Borrowings	Letters of Credit Outstanding	Available Capacity
Extended Revolving Credit Facility (a)	April 29, 2027	$ 3,175	$ —	$ 1,962	$ 1,213
Term Loan B-3 Facility (b)	December 20, 2030	2,500	2,500	—	—
Total Vistra Operations Credit Facilities		$ 5,675	$ 2,500	$ 1,962	$ 1,213
Commodity-Linked Facility (c)	October 2, 2024	$ 1,575	$ —	—	$ 1,101
Total Credit Facilities		$ 7,250	$ 2,500	$ 1,962	$ 2,314

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(a) Extended Revolving Credit Facility is used for general corporate purposes. Cash borrowings under the Extended Revolving Credit Facility are reported in short-term borrowings in our consolidated balance sheets. The full amount of Extended Revolving Credit Facility available capacity can be utilized to issue letters of credit. In December 2022, Vistra Operations terminated $350 million in Extended Revolving Credit Facility commitments.

(b) Effective December 20, 2023, cash borrowings under the Term Loan B-3 Facility are subject to required scheduled quarterly payments of $6.25 million beginning in March 2024. Amounts paid cannot be reborrowed.

(c) Commodity-Linked Facility (defined below) is used to support our comprehensive hedging strategy. As of December 31, 2023, the borrowing base of $1.101 billion is lower than the facility limit which represents aggregate commitments of $1.575 billion. See *Commodity-Linked Revolving Credit Facility* below for discussion of the borrowing base calculation. The Commodity-Linked Facility was amended in October 2023, increasing the aggregate commitments to $1.575 billion and extending the term to October 2024. The deemed hedge portfolio was also updated to reflect current hedge positions, including the addition of the 2025 deemed hedges. Cash borrowings under the Commodity-Linked Facility are reported in short-term borrowings in our consolidated balance sheets.

Under the Vistra Operations Credit Agreement, the interest applicable to the Extended Revolving Credit Facility is based on the forward-looking term rate based on SOFR (Term SOFR Rate) plus a spread that will range from 1.25% to 2.00%, based on the ratings of Vistra Operations' senior secured long-term debt securities, and the fee on any undrawn amounts with respect to the Extended Revolving Credit Facility will range from 17.5 basis points to 35.0 basis points, based on ratings of Vistra Operations' senior secured long-term debt securities. As of December 31, 2023, the applicable interest rate margins for the Extended Revolving Credit Facility and the fee for undrawn amounts relating to such extended commitments were lowered to 1.70% and 26.5 basis points, respectively, related to a sustainability pricing adjustment based on certain sustainability-linked targets and thresholds. As of December 31, 2023, there were no outstanding borrowings under the Extended Revolving Credit Facility. Letters of credit issued under the Extended Revolving Credit Facility bear interest that ranges from 1.25% to 2.00% (based on the ratings of Vistra Operations' senior secured long-term debt securities), which as of December 31, 2023 was reduced to 1.70% as a result of a sustainability pricing adjustment. The Vistra Operations Credit Facilities also provide for certain additional customary fees payable to the agents and lenders, including fronting fees with respect to outstanding letters of credit.

Effective December 20, 2023, the principal amount under the Term Loan B-3 Facility increased from $2.493 billion to $2.50 billion and bears interest based on the applicable Term SOFR Rate, plus a fixed spread of 2.00% and the weighted average interest rates before taking into consideration interest rate swaps on outstanding borrowings was 7.36% under the Term Loan B-3 Facility.

Obligations under the Vistra Operations Credit Facilities are secured by liens covering substantially all of Vistra Operations' (and certain of its subsidiaries') consolidated assets, rights and properties, subject to certain exceptions set forth in the Vistra Operations Credit Facilities. The Vistra Operations Credit Agreement includes certain collateral suspension provisions that would take effect upon Vistra Operations achieving unsecured investment grade ratings from two ratings agencies, there being no Term Loans (under and as defined in the Vistra Operations Credit Agreement) then outstanding (or the holders thereof agreeing to release such security interests), and there being no outstanding revolving credit commitments the maturities of which have not been extended to April 29, 2027 (or the holders thereof agreeing to release such security interests), such collateral suspension provisions would continue to be in effect unless and until Vistra Operations no longer holds unsecured investment grade ratings from at least two ratings agencies, at which point collateral reversion provisions would take effect (subject to a 60-day grace period).

The Vistra Operations Credit Facilities also permit certain hedging agreements and cash management agreements to be secured on a pari-passu basis with the Vistra Operations Credit Facilities in the event those hedging agreements and cash management agreements met certain criteria set forth in the Vistra Operations Credit Facilities.

The Vistra Operations Credit Facilities provide for affirmative and negative covenants applicable to Vistra Operations (and its restricted subsidiaries), including affirmative covenants requiring it to provide financial and other information to the agents under the Vistra Operations Credit Facilities and to not change its lines of business, and negative covenants restricting Vistra Operations' (and its restricted subsidiaries') ability to incur additional indebtedness, make investments, dispose of assets, pay dividends, grant liens or take certain other actions, in each case, except as permitted in the Vistra Operations Credit Facilities. Vistra Operations' ability to borrow under the Vistra Operations Credit Facilities is subject to the satisfaction of certain customary conditions precedent set forth therein.

The Vistra Operations Credit Facilities provide for certain customary events of default, including events of default resulting from non-payment of principal, interest or fees when due, material breaches of representations and warranties, material breaches of covenants in the Vistra Operations Credit Facilities or ancillary loan documents, cross-defaults under other agreements or instruments and the entry of material judgments against Vistra Operations. Solely with respect to the Revolving Credit Facility, and solely during a compliance period (which, in general, is applicable when the aggregate revolving borrowings and issued revolving letters of credit (in excess of $300 million) exceed 30% of the revolving commitments), the agreement includes a covenant that requires the consolidated first lien net leverage ratio, which is based on the ratio of net first lien debt compared to an EBITDA calculation defined under the terms of the Vistra Operations Credit Facilities, not to exceed 4.25 to 1.00 (or, during a collateral suspension period, the consolidated total net leverage ratio, which is based on the ratio of consolidated total debt compared to an EBITDA calculation defined under the terms of the Vistra Operations Credit Facilities, not to exceed 5.50 to 1.00). As of December 31, 2023, we were in compliance with this financial covenant. Upon the existence of an event of default, the Vistra Operations Credit Facilities provide that all principal, interest and other amounts due thereunder will become immediately due and payable, either automatically or at the election of specified lenders.

Commodity-Linked Revolving Credit Facility

In order to support our comprehensive hedging strategy, in February 2022, Vistra Operations entered into a $1.0 billion senior secured commodity-linked revolving credit facility (Commodity-Linked Facility) by and among Vistra Operations, Vistra Intermediate, the lenders, joint lead arrangers and joint bookrunners party thereto, and Citibank, N.A., as administrative agent and collateral agent. In May 2022, we entered into an amendment to the Commodity-Linked Facility to increase the aggregate available commitments from $1.0 billion to $2.0 billion and to provide the flexibility, subject to our ability to obtain additional commitments, to further increase the size of the Commodity-Linked Facility by an additional $1.0 billion to a facility size of $3.0 billion. Subsequent amendments in May 2022 and June 2022 increased the aggregate available commitments from $2.0 billion to $2.25 billion. In October 2022, Vistra initiated amendments to the Commodity-Linked Facility to, among other things, reduce the aggregate available commitments to $1.35 billion. In September 2023, the Commodity-Linked Credit Agreement was amended to (i) conform to changes and modifications consistent with the Vistra Operations Credit Agreement including to allow for the Energy Harbor acquisition and related additional financings contemplated by the Commitment Letter and (ii) give Vistra Operations the flexibility to update the deemed hedge portfolio that serves as the borrowing base under the Commodity-Linked Facility on a more frequent basis. In October 2023, Vistra Operations initiated amendments to the Commodity-Linked Facility to, among other things, (i) extend the maturity date to October 2, 2024 and (ii) increase the aggregate available commitments to $1.575 billion.

Under the Commodity-Linked Facility, the borrowing base is calculated on a weekly basis based on a set of theoretical transactions which approximate a portion of the hedge portfolio of Vistra Operations and certain of its subsidiaries in certain power markets, with availability thereunder not to exceed the aggregate available commitments nor be less than zero. Vistra Operations may, at its option, borrow an amount up to the borrowing base, as adjusted from time to time, provided that if outstanding borrowings at any time would exceed the borrowing base, Vistra Operations shall make a repayment to reduce outstanding borrowings to be less than or equal to the borrowing base. Vistra Operations intends to use any borrowings provided under the Commodity-Linked Facility to make cash postings as required under various commodity contracts to which Vistra Operations and its subsidiaries are parties as power prices increase from time-to time and for other working capital and general corporate purposes.

Under the Vistra Operations Commodity-Linked Credit Agreement, the interest applicable to the Commodity-Linked Facility is based on the Term SOFR Rate plus a spread that will range from 1.25% to 2.00%, based on the ratings of Vistra Operations' senior secured long-term debt securities, and the fee on any undrawn amounts with respect to the Commodity-Linked Facility will range from 17.5 basis points to 35.0 basis points, based on ratings of Vistra Operations' senior secured long-term debt securities. As of December 31, 2023, the applicable interest rate margins for the Commodity-Linked Facility and the fee on any undrawn amounts with respect to the Commodity-Linked Facility were lowered to 1.70% and 26.5 basis points, respectively, related to a sustainability pricing adjustment based on certain sustainability-linked targets and thresholds. As of December 31, 2023, there were no outstanding borrowings under the Commodity-Linked Facility.

The Vistra Operations Commodity-Linked Credit Agreement includes a covenant, solely during a compliance period (which, in general, is applicable when the aggregate revolving borrowings exceeds 30% of the revolving commitments), that requires the consolidated first lien net leverage ratio, which is based on the ratio of net first lien debt compared to an EBITDA calculation defined under the terms of the Commodity-Linked Facility, not to exceed 4.25 to 1.00 (or, during a collateral suspension period, the consolidated total net leverage ratio, which is based on the ratio of consolidated total debt compared to an EBITDA calculation defined under the terms of the Commodity-Linked Facility, not to exceed 5.50 to 1.00). As of December 31, 2023, we were in compliance with this financial covenant.

Interest Rate Swaps

Vistra employs interest rate swaps to hedge our exposure to variable rate debt. As of December 31, 2023, Vistra has entered into the following series of interest rate swap transactions. The rate ranges in the table below reflect the fixed leg of each swap plus an interest margin of 2.00%. The February 2024 and July 2026 swaps were amended in the second quarter of 2023 to reflect the conversion of LIBOR to SOFR.

	Notional Amount	Expiration Date	Rate Range			
Swapped to fixed	$600	February 2024	3.86	%	-	3.88%
Swapped to variable	$600	February 2024	3.35	%	-	3.36%
Swapped to fixed	$3,000	July 2026	4.89	%	-	4.97%
Swapped to variable	$700	July 2026	3.44	%	-	3.49%
Swapped to fixed (a)	$1,625	December 2030	5.20	%	-	5.37%

(a) Effective from July 2026 through December 2030.

During 2019, Vistra entered into interest rate swaps, pursuant to which Vistra will pay a variable rate and receive a fixed rate. The terms of these new swaps were matched against the terms of certain existing swaps, effectively offsetting the hedge of the existing swaps and fixing the out-of-the-money position of such swaps. These matched swaps will settle over time, in accordance with the original contractual terms. Swaps expiring in July 2026 continue to hedge our exposure on $2.30 billion of debt through July 2026.

In October 2023, Vistra settled and terminated $120 million notional amount of each series of interest rate swaps expiring in February 2024.

In March 2023, Vistra entered into $750 million notional amount of interest rate swaps to hedge future floating rate debt issuances. The swaps were effective as of December 31, 2023 and expire December 31, 2030. In December 2023, we settled the January 2024 through July 2026 mark-to-market gain of these swaps for $13 million in cash proceeds, amended the effective dates to July 31, 2026 and modified the fixed rate coupons to correspond with the one-month Term SOFR Rate. In addition, in December 2023, Vistra entered into $875 million notional amount of interest rate swaps effective July 31, 2026 and expire December 31, 2030. These swaps, along with the $750 million notional amount of interest rate swaps entered into in March 2023, will hedge our exposure on $1.625 billion of floating rate debt from August 2026 through December 2030.

Secured Letter of Credit Facilities

In August and September 2020, Vistra entered into uncommitted standby letter of credit facilities that are each secured by a first lien on substantially all of Vistra Operations' (and certain of its subsidiaries') assets (which ranks pari passu with the Vistra Operations Credit Facilities) (each, a Secured LOC Facility and collectively, the Secured LOC Facilities). The Secured LOC Facilities are used for general corporate purposes. In October 2021, September 2022 and October 2022, Vistra entered into additional Secured LOC Facilities which are used for general corporate purposes. As of December 31, 2023, $788 million of letters of credit were outstanding under the Secured LOC Facilities.

Each of the Secured LOC Facilities includes a covenant that requires the consolidated first-lien net leverage ratio not to exceed 4.25 to 1.00 (or, for certain facilities that include a collateral suspension mechanism, during a collateral suspension period, the consolidated total net leverage ratio not to exceed 5.50 to 1.00). As of December 31, 2023, we were in compliance with these financial covenants.

Vistra Operations Senior Secured Notes

In September and December 2023, Vistra Operations issued $650 million and $400 million, respectively, aggregate principal amount of 6.950% senior secured notes due 2033 (6.950% Senior Secured Notes) in offerings to eligible purchasers under Rule 144A and Regulation S under the Securities Act. The 6.950% Senior Secured Notes were sold pursuant to a purchase agreement by and among Vistra Operations, certain direct and indirect subsidiaries of Vistra Operations and Citigroup Global Markets Inc., as representative of the several initial purchasers. The 6.950% Senior Secured Notes mature in October 2033, with interest payable in cash semiannually in arrears on April 15 and October 15 beginning April 2024. Net proceeds from the September 2023 issuance totaling $643 million, together with proceeds from the September 2023 issuance of 7.750% Senior Unsecured Notes discussed below and cash on hand, will be used to fund the Transactions. Net proceeds from the December 2023 issuance totaling $412 million, together with proceeds from the December 2023 issuance of 7.750% Senior Unsecured Notes discussed below and cash on hand, were used to pay the purchase price and accrued interest (together with fees and expenses) required in connection with the Senior Secured Notes Tender Offer described below. In the year ended December 31, 2023, fees and expenses of $12 million and a debt premium of $9 million related to these offerings were capitalized as a reduction in the carrying amount of the debt.

In May 2022, Vistra Operations issued $1.5 billion aggregate principal amount of senior secured notes (2022 Senior Secured Notes), consisting of $400 million aggregate principal amount of 4.875% senior secured notes due 2024 (4.875% Senior Secured Notes) and $1.1 billion aggregate principal amount of 5.125% senior secured notes due 2025 (5.125% Senior Secured Notes) in an offering to eligible purchasers under Rule 144A and Regulation S under the Securities Act (Senior Secured Notes Offering). The 2022 Senior Secured Notes were sold pursuant to a purchase agreement by and among Vistra Operations, certain direct and indirect subsidiaries of Vistra Operations and Citigroup Global Markets Inc., as representative of the several initial purchasers. The 4.875% Senior Secured Notes mature in May 2024 and the 5.125% Senior Secured Notes mature in May 2025. Interest on the 2022 Senior Secured Notes is payable in cash semiannually in arrears on May 13 and November 13 of each year, beginning in November 2022. Net proceeds from the Senior Secured Notes Offering totaling $1.485 billion, together with cash on hand, were used to pay down borrowings under the Commodity-Linked Facility. Fees and expenses related to the offering totaled $17 million in the year ended December 31, 2023, which were capitalized as a reduction in the carrying amount of the debt.

Since 2019, Vistra Operations issued and sold $5.65 billion aggregate principal amount of senior secured notes in offerings to eligible purchasers under Rule 144A and Regulation S under the Securities Act. The indenture (as may be amended or supplemented from time to time, the Vistra Operations Senior Secured Indenture) governing the 3.550% senior secured notes due 2024, the 3.700% senior secured notes due 2027, the 4.300% senior secured notes due 2029, the 2022 Senior Secured Notes and the 6.950% Senior Secured Notes (collectively, as each may be amended or supplemented from time to time, the Senior Secured Notes) provides for the full and unconditional guarantee by certain of Vistra Operations' current and future subsidiaries that also guarantee the Vistra Operations Credit Facilities. The Senior Secured Notes are secured by a first-priority security interest in the same collateral that is pledged for the benefit of the lenders under the Vistra Operations Credit Facilities, which consists of a substantial portion of the property, assets and rights owned by Vistra Operations and certain direct and indirect subsidiaries of Vistra Operations as subsidiary guarantors (collectively, the Guarantor Subsidiaries) as well as the stock of Vistra Operations held by Vistra Intermediate. The collateral securing the Senior Secured Notes will be released if Vistra Operations' senior, unsecured long-term debt securities obtain an investment grade rating from two out of the three rating agencies, subject to reversion if such rating agencies withdraw the investment grade rating of Vistra Operations' senior, unsecured long-term debt securities or downgrade such rating below investment grade. The Vistra Operations Senior Secured Indenture contains certain covenants and restrictions, including, among others, restrictions on the ability of Vistra Operations and its subsidiaries, as applicable, to create certain liens, merge or consolidate with another entity, and sell all or substantially all of their assets.

Senior Secured Notes Tender Offer — In January 2024, Vistra Operations used the net proceeds from the December 2023 issuances of 6.950% Senior Secured Notes discussed above and 7.750% Senior Unsecured Notes discussed below and cash on hand to fund a cash tender offer (Senior Secured Notes Tender Offer) to purchase for cash $759 million aggregate principal amount of certain notes, including $58 million of 4.875% senior secured notes due 2024, $345 million of 3.550% senior secured notes due 2024 and $356 million of the 5.125% senior secured notes due 2025.

Vistra Operations Senior Unsecured Notes

In September and December 2023, Vistra Operations issued $1.1 billion and $350 million, respectively, aggregate principal amount of 7.750% senior unsecured notes due 2031 (7.750% Senior Unsecured Notes) in offerings to eligible purchasers under Rule 144A and Regulation S under the Securities Act. The 7.750% Senior Unsecured Notes were sold pursuant to a purchase agreement by and among Vistra Operations, certain direct and indirect subsidiaries of Vistra Operations and Citigroup Global Markets Inc., as representative of the several initial purchasers. The 7.750% Senior Unsecured Notes mature in October 2031, with interest payable in cash semiannually in arrears on April 15 and October 15 beginning April 2024. Net proceeds from the September 2023 issuances totaling $1.089 billion, together with proceeds from the September 2023 issuance of 6.950% Senior Secured Notes discussed above and cash on hand, will be used to fund the Transactions. Net proceeds from the December 2023 issuances totaling $360 million, together with proceeds from the December 2023 issuance of 6.950% Senior Secured Notes discussed above and cash on hand, were used to pay the purchase price and accrued interest (together with fees and expenses) required in connection with the Senior Secured Notes Tender Offer described above. In the year ended December 31, 2023, fees and expenses of $17 million and a debt premium of $7 million related to these offerings were capitalized as a reduction in the carrying amount of the debt.

In May 2021, Vistra Operations issued and sold $1.25 billion aggregate principal amount of 4.375% senior unsecured notes due 2029 in an offering to eligible purchasers under Rule 144A and Regulation S under the Securities Act. The 4.375% senior unsecured notes due 2029 were sold pursuant to a purchase agreement by and among Vistra Operations, the Guarantor Subsidiaries and J.P. Morgan Securities LLC, as representative of the several initial purchasers. The 4.375% senior unsecured notes mature in May 2029, with interest payable in arrears on May 1 and November 1 beginning November 1, 2021 with interest accrued from May 10, 2021. Net proceeds, together with cash on hand, were used to repay all amounts outstanding under the Term Loan A Facility and to pay fees and expenses of $15 million related to the offering. Fees and expenses were capitalized as a reduction in the carrying amount of the debt.

Since 2018, Vistra Operations has issued and sold $6.30 billion aggregate principal amount of senior unsecured notes in offerings to eligible purchasers under Rule 144A and Regulation S under the Securities Act. The indentures governing the 5.500% senior unsecured notes due 2026, the 5.625% senior unsecured notes due 2027, the 5.000% senior unsecured notes due 2027, the 4.375% senior unsecured notes due 2029 and the 7.750% Senior Unsecured Notes (collectively, as each may be amended or supplemented from time to time, the Vistra Operations Senior Unsecured Indentures) provide for the full and unconditional guarantee by the Guarantor Subsidiaries of the punctual payment of the principal and interest on such notes. The Vistra Operations Senior Unsecured Indentures contain certain covenants and restrictions, including, among others, restrictions on the ability of Vistra Operations and its subsidiaries, as applicable, to create certain liens, merge or consolidate with another entity, and sell all or substantially all of their assets.

Debt Repurchase Program

In March 2021, the Board authorized up to $1.8 billion to voluntarily repay or repurchase outstanding debt, which authorization expired in March 2022 (Prior Authorization). No amounts were repurchased under the Prior Authorization. In October 2022, the Board re-authorized the voluntary repayment or repurchase of up to $1.8 billion of outstanding debt, with such authorization expiring on December 31, 2023 (Updated Authorization). Through December 31, 2023, no amounts were repurchased under the Updated Authorization.

Maturities

Long-term debt maturities at December 31, 2023 are as follows:

	December 31, 2023
2024	$ 2,293
2025	779
2026	1,031
2027	3,427
2028	27
Thereafter	6,960
Unamortized premiums, discounts and debt issuance costs	(115)
Total long-term debt, including amounts due currently	$ 14,402

13. LEASES

Vistra has both finance and operating leases for real estate, rail cars and equipment. Our leases have remaining lease terms for 1 to 34 years. Our leases include options to renew up to 15 years. Certain leases also contain options to terminate the lease.

Lease Cost

The following table presents costs related to lease activities:

	Year Ended December 31,		
	2023	2022	2021
Operating lease cost	$ 12	$ 9	$ 11
Finance lease:			
Finance lease right-of-use asset amortization	10	9	9
Interest on lease liabilities	11	12	10
Total finance lease cost	21	21	19
Variable lease cost (a)	37	22	29
Short-term lease cost	44	47	35
Sublease income (b)	—	—	(7)
Net lease cost	$ 114	$ 99	$ 87

(a) Represents coal stockpile management services, common area maintenance services, and rail car payments based on the number of rail cars used.
(b) Represents sublease income related to real estate leases.

Balance Sheet Information

The following table presents lease related balance sheet information:

	December 31,	
	2023	2022
Lease assets:		
Operating lease right-of-use assets	$ 50	$ 51
Finance lease right-of-use assets (net of accumulated depreciation)	160	$ 173
Total lease right-of-use assets	210	224
Current lease liabilities:		
Operating lease liabilities	7	8
Finance lease liabilities	9	9
Total current lease liabilities	16	17
Noncurrent lease liabilities:		
Operating lease liabilities	48	45
Finance lease liabilities	227	237
Total noncurrent lease liabilities	275	282
Total lease liabilities	$ 291	$ 299

Supplemental Cash Flow Information

The following table presents lease related cash flows and other information:

	Year Ended December 31,		
	2023	2022	2021
Non-cash disclosure upon commencement of new lease:			
Right-of-use assets obtained in exchange for new operating lease liabilities	3	19	7
Right-of-use assets obtained in exchange for new finance lease liabilities	—	6	—
Non-cash disclosure upon modification of existing lease:			
Modification of operating lease right-of-use assets	7	—	(4)
Modification of finance lease right-of-use assets	(1)	4	(1)

Weighted Average Remaining Lease Term

The following table presents weighted average remaining lease term information:

	December 31,	
	2023	2022
Weighted average remaining lease term:		
Operating lease	20.1 years	15.8 years
Finance lease	24.0 years	24.2 years
Weighted average discount rate:		
Operating lease	6.49%	6.26 %
Finance lease	4.81%	4.81 %

Maturity of Lease Liabilities

The following table presents maturity of lease liabilities:

	Operating Lease	Finance Lease	Total Lease
2024	$ 10	$ 20	$ 30
2025	7	19	26
2026	4	14	18
2027	4	13	17
2028	4	13	17
Thereafter	77	345	422
Total lease payments	106	424	530
Less: Interest	(51)	(188)	(239)
Present value of lease liabilities	$ 55	$ 236	$ 291

14. COMMITMENTS AND CONTINGENCIES

Contractual Commitments

As of December 31, 2023, we had minimum contractual commitments under long-term service and maintenance contracts, energy-related contracts and other agreements as follows:

	Long-Term Service and Maintenance Contracts (a)	Coal transportation agreements	Pipeline transportation and storage reservation fees	Water Contracts
2024	$ 286	$ 33	$ 179	$ 9
2025	242	34	182	9
2026	228	35	192	9
2027	250	36	195	9
2028	310	—	194	9
Thereafter	2,091	—	96	44
Total	$ 3,407	$ 138	$ 1,038	$ 89

(a) Long-term service and maintenance contracts reflect expected expenditures as these contracts do not include minimum spending requirements, but can only be terminated based on events outside the control of the Company.

In addition to the commitments detailed above, we have nuclear fuel contracts with early termination penalties. As of December 31, 2023, termination costs of $61 million would be incurred if we terminated those contracts.

Expenditures under our coal purchase and coal transportation agreements totaled $936 million, $995 million, and $850 million for the years ended December 31, 2023, 2022 and 2021, respectively.

Guarantees

We have entered into contracts that contain guarantees to unaffiliated parties that could require performance or payment under certain conditions. Material guarantees are discussed below.

Letters of Credit

As of December 31, 2023, we had outstanding letters of credit totaling $2.750 billion as follows:

- $2.408 billion to support commodity risk management collateral requirements in the normal course of business, including over-the-counter and exchange-traded transactions and collateral postings with ISOs/RTOs;
- $186 million to support battery and solar development projects;
- $27 million to support executory contracts and insurance agreements;
- $91 million to support our REP financial requirements with the PUCT; and
- $38 million for other credit support requirements.

Surety Bonds

As of December 31, 2023, we had outstanding surety bonds totaling $935 million to support performance under various contracts and legal obligations in the normal course of business.

Litigation and Regulatory Proceedings

Our material legal proceedings and regulatory proceedings affecting our business are described below. We believe that we have valid defenses to the legal proceedings described below and intend to defend them vigorously. We also intend to participate in the regulatory processes described below. We record reserves for estimated losses related to these matters when information available indicates that a loss is probable and the amount of the loss, or range of loss, can be reasonably estimated. As applicable, we have established an adequate reserve for the matters discussed below. In addition, legal costs are expensed as incurred. Management has assessed each of the following legal matters based on current information and made a judgment concerning its potential outcome, considering the nature of the claim, the amount and nature of damages sought, and the probability of success. Unless specified below, we are unable to predict the outcome of these matters or reasonably estimate the scope or amount of any associated costs and potential liabilities, but they could have a material impact on our results of operations, liquidity, or financial condition. As additional information becomes available, we adjust our assessment and estimates of such contingencies accordingly. Because litigation and rulemaking proceedings are subject to inherent uncertainties and unfavorable rulings or developments, it is possible that the ultimate resolution of these matters could be at amounts that are different from our currently recorded reserves and that such differences could be material.

Litigation

Natural Gas Index Pricing Litigation — We, through our subsidiaries, and another company remain named as defendants in one consolidated putative class action lawsuit pending in federal court in Wisconsin claiming damages resulting from alleged price manipulation through false reporting of natural gas prices to various index publications, wash trading and churn trading from 2000-2002. The plaintiffs in these cases allege that the defendants engaged in an antitrust conspiracy to inflate natural gas prices during the relevant time period and seek damages under the respective state antitrust statutes. In April 2023, the U.S. Court of Appeals for the Seventh Circuit (Seventh Circuit Court) heard oral argument on an interlocutory appeal challenging the district court's order certifying a class.

Illinois Attorney General Complaint Against Illinois Gas & Electric (IG&E) — In May 2022, the Illinois Attorney General filed a complaint against IG&E, a subsidiary we acquired when we purchased Crius in July 2019. The complaint filed in Illinois state court alleges, among other things, that IG&E engaged in improper marketing conduct and overcharged customers. The vast majority of the conduct in question occurred prior to our acquisition of IG&E. In July 2022, we moved to dismiss the complaint, and in October 2022, the district court granted in part our motion to dismiss, barring all claims asserted by the Illinois Attorney General that were outside of the 5-year statute of limitations period, which now limits the period during which claims may be made to start in May 2017 rather than extending back to 2013 as the Illinois Attorney General had alleged in its complaint.

Winter Storm Uri Legal Proceedings

Repricing Challenges — In March 2021, we filed an appeal in the Third Court of Appeals in Austin, Texas (Third Court of Appeals), challenging the PUCT's February 15 and February 16, 2021 orders governing ERCOT's determination of wholesale power prices during load-shedding events. Other parties also supported our challenge to the PUCT's orders. In March 2023, the Third Court of Appeals issued a unanimous decision and agreed with our arguments that the PUCT's pricing orders constituted de facto competition rules and exceeded the PUCT's statutory authority. The Third Court of Appeals vacated the pricing orders and remanded the matter to the PUCT for further proceedings. In March 2023, the PUCT appealed the Third Court of Appeals' ruling to the Texas Supreme Court. In September 2023, the Texas Supreme Court granted the PUC and its intervenors petitions for review of the Third Court of Appeals' decision and the Court heard oral argument in January 2024. In addition, we have also submitted settlement disputes with ERCOT over power prices and other issues during Winter Storm Uri. Following an appeal of the PUCT's March 5, 2021 verbal order and other statements made by the PUCT, the Texas Attorney General, on behalf of the PUCT, its client, represented in a letter agreement filed with the Third Court of Appeals that we and other parties may continue disputing the pricing during Winter Storm Uri through the ERCOT process and, to the extent the outcome of that process comes before the PUCT for review, the PUCT has not prejudged or made a final decision on that matter. We are not able to reasonably estimate the financial statement impact of a repricing as, among other things, the matter is subject to ongoing legal proceedings and, even if we were ultimately successful in the current legal proceeding, the price at which the market would be resettled is not reasonably estimable because that would be subject to further proceedings at ERCOT and the PUCT.

Regulatory Investigations and Other Litigation Matters — Following the events of Winter Storm Uri, various regulatory bodies, including ERCOT, the ERCOT Independent Market Monitor, the Texas Attorney General, the FERC and the NRC initiated investigations or issued requests for information of various parties related to the significant load shed event that occurred during the event as well as operational challenges for generators arising from the event, including performance and fuel and supply issues. We responded to all those investigatory requests. In addition, a large number of personal injury and wrongful death lawsuits related to Winter Storm Uri have been, and continue to be, filed in various Texas state courts against us and numerous generators, transmission and distribution utilities, retail and electric providers, as well as ERCOT. We and other defendants requested that all pretrial proceedings in these personal injury cases be consolidated and transferred to a single multi-district litigation (MDL) pretrial judge. In June 2021, the MDL panel granted the request to consolidate all these cases into an MDL for pretrial proceedings. Additional personal injury cases that have been, and continue to be, filed on behalf of additional plaintiffs have been consolidated with the MDL proceedings. In addition, in January 2022, an insurance subrogation lawsuit was filed in Austin state court by over one hundred insurance companies against ERCOT, Vistra and several other defendants. The lawsuit seeks recovery of insurance funds paid out by these insurance companies to various policyholders for claims related to Winter Storm Uri, and that case has also now been consolidated with the MDL proceedings. In the summer of 2022, various defendant groups filed motions to dismiss five so-called bellwether cases, and the MDL court heard oral argument on those motions in October 2022. In January 2023, the MDL court ruled on the various motions to dismiss and denied the motions to dismiss of the generator defendants and the transmission distribution utilities defendants, but granted the motions of some of the other defendant groups, including the retail electric providers and ERCOT. In February 2023, the generator defendants filed a mandamus petition with the First Court of Appeals in Houston, Texas (First Court of Appeals) to review the MDL court's denial of the motion to dismiss. In December 2023, the First Court of Appeals in a unanimous decision granted our mandamus petition and instructed the MDL court to grant the motions to dismiss in full filed by the generator defendants. In January 2024, the plaintiffs filed a request with the full Court of Appeals to review that panel ruling. We believe we have strong defenses to these lawsuits and intend to defend against these cases vigorously.

Greenhouse Gas Emissions (GHG)

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 generation 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 opened a docket seeking input on questions related to the regulation of GHGs under Section 111(d) which closed in March 2023. In May 2023, the EPA released a new proposal regulating power plant GHG emissions, while also proposing to repeal the ACE rule. The new GHG proposal sets limits for (a) new natural gas-fired combustion turbines, (b) existing coal-, oil- and natural gas-fired steam generation units, and (c) certain existing natural gas-fired combustion turbines. The proposed standards are based on technologies such as carbon capture and sequestration/storage (CCS), low-GHG hydrogen co-firing, and natural gas co-firing. Starting in 2030, the proposal would generally require more CO_2 emissions control at fossil fuel-fired power plants that operate more frequently and for more years and would phase in increasingly stringent CO_2 requirements over time. Under the proposal, states would be required to submit plans to the EPA within 24 months of the rule's effective date that provide for the establishment, implementation, and enforcement of standards of performance for existing sources. These state plans must generally establish standards that are at least as stringent as the EPA's emission guidelines. Existing steam generation units must start complying with their standards of performance on January 1, 2030. Existing combustion turbine units must start complying with their standards of performance on January 1, 2032, or January 1, 2035, depending on their subcategory. We submitted comments to the EPA on this proposal in August 2023.

Cross-State Air Pollution Rule (CSAPR)

In October 2015, the EPA revised the primary and secondary ozone National Ambient Air Quality Standards (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' SIP and the State of Texas, Luminant, certain trade groups, and others challenged that disapproval in the U.S. Court of Appeals for the Fifth Circuit (Fifth Circuit Court). In March 2023, those same parties filed motions to stay the EPA's SIP disapproval in the Fifth Circuit Court, and the EPA moved to transfer our challenges to the D.C. Circuit Court or have those challenges dismissed.

In April 2022, prior to the EPA's disapproval of Texas' SIP, the EPA proposed a Federal Implementation Plan (FIP) to address the 2015 ozone NAAQS. 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. In March 2023, the EPA administrator signed its final FIP. The FIP applies to 22 states beginning with the 2023 ozone seasons. States where Vistra operates generation units that would be subject to this rule are Illinois, New Jersey, New York, Ohio, Pennsylvania, Texas, Virginia and West Virginia. Texas would be moved into the revised (and more restrictive) Group 3 trading program previously established in the Revised CSAPR Update Rule that includes emission budgets for 2023 that the EPA says are achievable through existing controls installed at power plants. Allowances will be limited under the program and will be further reduced beginning in ozone season 2026 to a level that is intended to reduce operating time of coal-fueled power plants during ozone season or force coal plants to retire, particularly those that do not have selective catalytic reduction systems such as our Martin Lake power plant.

In May 2023, the Fifth Circuit Court granted our motion to stay the EPA's disapproval of Texas' SIP pending a decision on the merits and denied the EPA's motion to transfer our challenge to the D.C. Circuit Court. As a result of the stay, we do not believe the EPA has authority to implement the FIP as to Texas sources pending the resolution of the merits, meaning that Texas will remain in Group 2 and not be subject to any requirements under the FIP at least until the Fifth Circuit Court rules on the merits. Oral argument was heard in December 2023 before the Fifth Circuit Court. In June 2023, the EPA published the final FIP in the Federal Register, which included requirements as to Texas despite the stay of the SIP disapproval by the Fifth Circuit Court. In June 2023, the State of Texas, Luminant and various other parties also filed challenges to the FIP in the Fifth Circuit Court, filed a motion to stay the FIP and confirm venue for this dispute in the Fifth Circuit Court. After the motion to stay and to confirm venue was filed, the EPA signed an interim final rule on June 29, 2023 that confirms the FIP as to Texas is stayed. In July 2023, the Fifth Circuit Court ruled that the FIP challenge would be held in abeyance pending the resolution of the litigation on the SIP disapproval and denied the motion to stay as not needed given the EPA's administrative stay.

Regional Haze — Reasonable Progress and Best Available Retrofit Technology (BART) for Texas

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 generation 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 is in the process of reconsidering the BART rule, and the challenges in the D.C. Circuit Court have been held in abeyance pending the EPA's final action on reconsideration. In May 2023, a proposed BART rule was published in the Federal Register that would withdraw the trading program provisions of the prior rule and would establish SO_2 limits on six facilities in Texas, including Martin Lake and Coleto Creek. Under the current proposal, compliance would be required within 3 years for Martin Lake and 5 years for Coleto Creek. Due to the announced shutdown for Coleto Creek, we do not anticipate any impacts at that facility, and we are evaluating potential compliance options at Martin Lake should this proposal become final. We submitted comments to the EPA on this proposal in August 2023.

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. In January 2024, in a split decision, the Fifth Circuit Court denied the petitions for review we and the State of Texas filed over the EPA's 2016 nonattainment designation for SO_2 for the area around Martin Lake. As a result of this decision, the EPA's nonattainment designation – originally made in 2016 – remains in place. We anticipate the EPA will likely move forward with either proposing a federal plan for the area in light of an approved consent decree between the Sierra Club and the EPA that requires the EPA taking final action promulgating a FIP for the nonattainment area by December 13, 2024 or the EPA may approve Texas' SIP submittal discussed above. In February 2024, we filed a petition asking the full Fifth Circuit Court to review the panel decision issued in January 2024.

***Particulate Matte*r**

In February 2024, the EPA issued a rule addressing the annual health-based national ambient air quality standards for fine particulate matter (or PM2.5). In general, the rule lowers the level of the annual PM2.5 standard from 12.0 micrograms per cubic meter (µg/m3) to 9.0 µg/m3. The effective date of the rule is 60 days from publication in the Federal Register, and the earliest attainment date for areas exceeding the new standard is 2032. At this time, we are still determining what impact, if any, this rule will have on our existing plants or any plants we may build in the future. Based on 2020-2022 design value associated with the rule, we have just five plants (Oakland (California), Calumet (Illinois), Liberty (Pennsylvania), Miami Fort (Ohio) and Lake Hubbard (Texas)) operating in areas where the air quality monitoring data are currently exceeding the new PM2.5 standard. We have previously announced that our Miami Fort generation facility will close by the end of 2027. States will have to develop a plan (by late 2027 at the earliest) to get those areas into attainment and there would be a possibility that additional controls would be required for those sites. However, before the state begins this planning process, the designation process will occur within two years from the issuance of the final rule. The states develop recommendations about the boundaries of the nonattainment counties and the EPA must finalize the designations including the boundaries of each nonattainment area.

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 flue gas desulfurization (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. 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. In March 2023, the EPA published its proposed supplemental ELG rule, which retains the retirement exemption from the 2020 ELG rule and sets new limits for plants that are continuing to operate. The proposed rule also establishes pretreatment standards for combustion residual leachate, and we are currently evaluating the impact of those proposed requirements. We submitted comments on the proposal in May 2023.

Coal Combustion Residuals (CCR)/Groundwater

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 2022 and 2023, we withdrew the applications for Coffeen, Martin Lake, Joppa and Zimmer stations because extensions were no longer needed. 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 application for an alternate liner demonstration for one CCR unit at Martin Lake, however, we withdrew the application for an alternate liner demonstration in November 2023 after determining the pond was no longer needed for CCR. In August 2021, we submitted a request to transfer our conversion application for the Zimmer facility to a retirement application following the 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 before the D.C. Circuit Court is complete and the court will hear argument in March 2024.

In May 2023, the EPA issued another proposal that further revises the federal CCR rule that would expand coverage of groundwater monitoring and closure requirements to the following two new categories of units: (a) legacy units which are CCR impoundments at inactive sites that ceased receiving waste before October 19, 2015 and (b) so-called "CCR management units" which generally could encompass areas of CCR located at a facility that is currently regulated by the existing CCR rule. CCR Management Units, as defined by the EPA in the proposal, could include any ash deposits, haul roads, and previously closed impoundments and landfills. As part of the proposed rule, the EPA identified 134 CCR management units at 82 different facilities across the country, including six of our potential units. The Vermilion ash ponds discussed below are the only unit which we believe qualify as a legacy CCR surface impoundment and given our closure plan for that site we do not believe this proposal, if finalized, will have any impact on that site. We are continuing to evaluate what would be required of the CCR management units identified in the proposal should the proposal become final in its current form. We submitted comments in July 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 Seventh Circuit Court affirmed the district court's dismissal of the lawsuit. In April 2019, PRN also filed a complaint against DMG before the 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. In July 2023, PRN filed an unopposed motion to voluntarily dismiss the case with prejudice, which the IPCB granted in August 2023 and closed the case.

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. In June 2023, the Illinois state court approved and entered the final consent order, which included the terms above and a requirement that when IEPA issues a final closure permit for the site, DMG will demolish the power station and submit for approval to construct an on-site landfill within the footprint of the former plant to store and manage the coal ash. These proposed closure costs are reflected in the ARO in our consolidated balance sheets (see Note 22).

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 was filed for our Baldwin facility in August 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 CCR surface impoundment and landfill closure costs currently reflected in our existing ARO liabilities reflect the costs of closure methods that our operations and environmental services teams believe are appropriate based on existing closure requirements and protective of the environment for each location. Once the IEPA acts on our permit applications, we will reassess the decommissioning costs and adjust our ARO liabilities accordingly.

MISO 2015-2016 Planning Resource Auction

In May 2015, three complaints were filed at the FERC regarding the Zone 4 results for the 2015-2016 planning resource auction (PRA) conducted by MISO. Dynegy is a named party in one of the complaints. The complainants, Public Citizen, Inc., the Illinois Attorney General and Southwestern Electric Cooperative, Inc. (Complainants), challenged the results of the PRA as unjust and unreasonable, requested rate relief/refunds, and requested changes to the MISO planning resource auction structure going forward. Complainants also alleged that Dynegy may have engaged in economic or physical withholding in Zone 4 constituting market manipulation in the PRA. The Independent Market Monitor for MISO (MISO IMM), which was responsible for monitoring the PRA, determined that all offers were competitive and that no physical or economic withholding occurred. The MISO IMM also stated, in a filing responding to the complaints, that there is no basis for the remedies sought by the Complainants. We filed our answer to these complaints explaining that we complied fully with the terms of the MISO tariff in connection with the PRA and disputing the allegations. The Illinois Industrial Energy Consumers filed a related complaint at the FERC against MISO in June 2015 requesting prospective changes to the MISO tariff. Dynegy also responded to this complaint with respect to Dynegy's conduct alleged in the complaint.

In October 2015, the FERC issued an order of nonpublic, formal investigation (the investigation) into whether market manipulation or other potential violations of the FERC orders, rules and regulations occurred before or during the PRA.

In December 2015, the FERC issued an order on the complaints requiring a number of prospective changes to the MISO tariff provisions effective as of the 2016-2017 planning resource auction. The order did not address the arguments of the Complainants regarding the PRA and stated that those issues remained under consideration and would be addressed in a future order.

In July 2019, the FERC issued an order denying the remaining issues raised by the complaints and noted that the investigation into Dynegy was closed. The FERC found that Dynegy's conduct did not constitute market manipulation and the results of the PRA were just and reasonable because the PRA was conducted in accordance with MISO's tariff. A request for rehearing was denied by the FERC in March 2020. The order was appealed by Public Citizen, Inc. to the D.C. Circuit Court in May 2020, and Vistra, Dynegy and Illinois Power Marketing Company intervened in the case in June 2020. In August 2021, the D.C. Circuit Court issued a ruling denying Public Citizen, Inc.'s arguments that the FERC failed to meet its obligation to ensure just and reasonable rates because it did not review the prices resulting from the auction before those prices went into effect and that the FERC was arbitrary and capricious in failing to adequately explain its decision to close its investigation into whether Dynegy engaged in market manipulation. The D.C. Circuit Court of Appeals granted Public Citizen, Inc.'s petition in part finding that the FERC's decision that the auction results were just and reasonable solely because the auction process complied with the filed tariff was unreasoned and remanded the case back to the FERC for further proceedings on that issue. On February 4, 2022 the Illinois Attorney General and Public Citizen, Inc. filed a motion at the FERC requesting that the FERC on remand reverse its prior decision and either find that auction results were not just and reasonable and order Dynegy to pay refunds to Illinois or, in the alternative, initiate an evidentiary hearing and discovery. We filed a response to this motion and will continue to vigorously defend our position. In June 2022, the FERC issued an order on remand establishing paper hearing procedures and directing the Office of Enforcement to file a remand report within 90 days providing the Office of Enforcement's assessment of Dynegy's actions with regard to the 2015-2016 planning resource auction. Although the FERC directed the Office of Enforcement to file a remand report, the FERC stated in the June 2022 order that it is not reopening the Office of Enforcement investigation. In September 2022, the Office of Enforcement filed its remand report stating that the Office of Enforcement staff found during its investigation that Dynegy knowingly engaged in manipulative behavior to set the Zone 4 price in the 2015-2016 PRA. In June 2023, the Company filed its initial brief and response to the remand report, and in August 2023 the Company filed a reply to the initial briefs from other parties. We will continue to vigorously defend our position.

Other Matters

We are involved in various legal and administrative proceedings and other disputes in the normal course of business, the ultimate resolutions of which, in the opinion of management, are not anticipated to have a material effect on our results of operations, liquidity or financial condition.

Labor Contracts

We employ certain personnel who are represented by labor unions, the terms of whose employment are governed 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 operations, as well as some battery operations, expire on various dates between March 2024 and March 2028, but remain effective thereafter unless and until terminated by either party. While we cannot predict the outcome of labor contract negotiations, we do not expect any changes in our existing agreements to have a material adverse effect on our results of operations, liquidity or financial condition.

Nuclear Insurance

Nuclear insurance includes nuclear liability coverage, property damage, nuclear accident decontamination and accidental premature decommissioning coverage and accidental outage and/or extra expense coverage. We maintain nuclear insurance that meets or exceeds requirements promulgated by Section 170 (Price-Anderson) of the Atomic Energy Act (the Act) and Title 10 of the Code of Federal Regulations. We intend to maintain insurance against nuclear risks as long as such insurance is available. We are self-insured to the extent that losses (i) are within the policy deductibles, (ii) are not covered per policy exclusions, terms and limitations, (iii) exceed the amount of insurance maintained, or (iv) are not covered due to lack of insurance availability. Any such self-insured losses could have a material adverse effect on our results of operations, liquidity or financial condition.

With regard to nuclear liability coverage, the Act provides for financial protection for the public in the event of a significant nuclear generation plant incident. The Act sets the statutory limit of public liability for a single nuclear incident at $16.2 billion and requires nuclear generation plant operators to provide financial protection for this amount. However, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay claims that exceed the $16.2 billion limit for a single incident. As required, we insure against a possible nuclear incident at our Comanche Peak facility resulting in public nuclear-related bodily injury and property damage through a combination of private insurance and an industry-wide retrospective payment plan known as Secondary Financial Protection (SFP).

Under the SFP, in the event of any single nuclear liability loss in excess of $450 million at any nuclear generation facility in the U.S., each operating licensed reactor in the U.S. is subject to an assessment of up to $165.9 million. This approximately $165.9 million maximum assessment is subject to increases for inflation every five years, with the next expected adjustment scheduled to occur by November 2028. Assessments are currently limited to $24.7 million per operating licensed reactor per year per incident. As of December 31, 2023, our maximum potential assessment under the industry retrospective plan would be approximately $331.8 million per incident but no more than $49.4 million in any one year for each incident. The potential assessment is triggered by a nuclear liability loss in excess of $450 million per accident at any nuclear facility. Effective January 1, 2024, the potential assessment is triggered by a nuclear liability loss in excess of $500 million per accident at any nuclear facility.

The United States Nuclear Regulatory Commission (NRC) requires that nuclear generation plant license holders maintain at least $1.06 billion of nuclear accident decontamination and reactor damage stabilization insurance, and requires that the proceeds thereof be used to place a plant in a safe and stable condition, to decontaminate a plant pursuant to a plan submitted to, and approved by, the NRC prior to using the proceeds for plant repair or restoration, or to provide for premature decommissioning. We maintain nuclear accident decontamination and reactor damage stabilization insurance for our Comanche Peak facility in the amount of $2.25 billion and non-nuclear accident related property damage in the amount of $1.0 billion (subject to a $5 million deductible per accident except for natural hazards which are subject to a $9.5 million deductible per accident), above which we are self-insured.

We also maintain Accidental Outage insurance to help cover the additional costs of obtaining replacement electricity from another source if one or both of the units at our Comanche Peak facility are out of service for more than twelve weeks as a result of covered direct physical damage. Such coverage provides for weekly payments per unit up to $4.5 million for the first 52 weeks and up to $3.6 million for a remaining 26 weeks for non-nuclear and 71 weeks for nuclear property damage outages. The total maximum coverage is $328 million for non-nuclear property damage and $490 million for nuclear property damage outages. The coverage amounts applicable to each unit will be reduced to 80% if both units are out of service at the same time as a result of the same accident.

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15. EQUITY

Common Stock Issuances and Repurchases

Changes in the number of shares of common stock issued and outstanding for the years ended December 31, 2023, 2022 and 2021 are reflected in the table below.

	Shares Issued	Treasury Shares	Shares Outstanding
Balance at December 31, 2020	530,349,112	(41,043,224)	489,305,888
Shares issued (a)	2,583,761	—	2,583,761
Shares retired	(3,397)	—	(3,397)
Shares repurchased (b)	—	(27,988,518)	(27,988,518)
Balance at December 31, 2021	532,929,476	(69,031,742)	463,897,734
Shares issued (a)	4,262,575	—	4,262,575
Shares retired	(12,979)	—	(12,979)
Shares repurchased (b)	—	(78,470,547)	(78,470,547)
Balance at December 31, 2022	537,179,072	(147,502,289)	389,676,783
Shares issued (a)	6,474,491	—	6,474,491
Shares retired	(18,391)	—	(18,391)
Shares repurchased (b)	—	(44,994,499)	(44,994,499)
Balance at December 31, 2023	543,635,172	(192,496,788)	351,138,384

(a) Shares issued include share awards granted to nonemployee directors.
(b) Shares repurchased include 318,632, 78,087 and 5,174,863 of unsettled shares as of December 31, 2023, 2022 and 2021, respectively.

Share Repurchase Programs

Current Share Repurchase Program — In October 2021, we announced that the Board authorized a share repurchase program (Share Repurchase Program) under which up to $2.0 billion of our outstanding shares of common stock may be repurchased. The Share Repurchase Program became effective on October 11, 2021, at which time it superseded the 2020 Share Repurchase Program (described below) and any authorization remaining as of such date. In August 2022, March 2023 and February 2024, the Board authorized incremental amounts of $1.25 billion, $1.0 billion and $1.5 billion, respectively, for repurchases to bring the total authorized under the Share Repurchase Program to $5.75 billion.

	$5.75 Billion Board Authorization			
	Total Number of Shares Repurchased	Average Price Paid Per Share	Amount Paid for Shares Repurchased	Amount Available for Additional Repurchases at the End of the Period
Year Ended December 31, 2021	19,330,365	$ 21.16	$ 409	
Year Ended December 31, 2022	78,470,547	$ 23.40	$ 1,836	
Year Ended December 31, 2023 (a)	44,994,499	27.89	1,255	
Total repurchased through December 31, 2023	142,795,411	$ 24.51	$ 3,500	$ 750
January 1, 2024 through February 23, 2024	4,489,651	41.39	186	
Total repurchased through February 23, 2024 (b)	147,285,062	$ 25.03	$ 3,686	$ 2,064

(a) Shares repurchased include 318,632 of unsettled shares for $12 million as of December 31, 2023.
(b) Amount available for additional repurchases at the end of the period includes additional $1.5 billion authorization approved by the Board in February 2024.

Under the Share Repurchase Program, shares of the Company's common stock may be repurchased in open market transactions at prevailing market prices, in privately negotiated transactions, pursuant to plans complying with the Exchange Act, or by other means in accordance with federal securities laws. The actual timing, number and value of shares repurchased under the Share Repurchase Program or otherwise will be determined at our discretion and will depend on a number of factors, including our capital allocation priorities, the market price of our stock, general market and economic conditions, applicable legal requirements and compliance with the terms of our debt agreements and the certificates of designation of the Series A Preferred Stock, the Series B Preferred Stock and the Series C Preferred Stock, respectively.

Superseded Share Repurchase Program — In September 2020, we announced that the Board authorized a share repurchase program (2020 Share Repurchase Program) under which up to $1.5 billion of our outstanding shares of common stock may be repurchased. The 2020 Share Repurchase Program was effective on January 1, 2021. In the year ended December 31, 2021, 8,658,153 shares of our common stock were repurchased under the 2020 Share Repurchase Program for approximately $175 million at an average price of $20.21 per share of common stock. The 2020 Share Repurchase Program was superseded by the Share Repurchase Program described above in October 2021.

Preferred Stock

On October 15, 2021 (Series A Issuance Date), we issued 1,000,000 shares of Series A Preferred Stock in a private offering (Series A Offering). The net proceeds of the Series A Offering were approximately $990 million, after deducting underwriting commissions and offering expenses. We intend to use the net proceeds from the Series A Offering to repurchase shares of our outstanding common stock under the Share Repurchase Program (described above).

On December 10, 2021 (Series B Issuance Date), we issued 1,000,000 shares of Series B Preferred Stock in a private offering (Series B Offering). The net proceeds of the Series B Offering were approximately $985 million, after deducting underwriting commissions and offering expenses. We intend to use the net proceeds from the Series B Offering to pay for or reimburse existing and new eligible renewable and battery ESS developments.

On December 29, 2023 (Series C Issuance Date), we issued 476,081 shares of Series C Preferred Stock (Series C Offering) in exchange for 74% of outstanding TRA rights (see Note 8). We recorded the issuance at fair value of $476 million. In determining the fair value of the Series C Preferred Stock as of the issuance date, we utilized the market approach described in ASC 820, *Fair Value Measurement,* which considers relevant observable market information for comparable instruments and is classified as Level 2 in the fair value hierarchy.

The Series A Preferred Stock, the Series B Preferred Stock and the Series C Preferred Stock are not convertible into or exchangeable for any other securities of the Company and have limited voting rights. The Series A Preferred Stock may be redeemed at the option of the Company at any time after the Series A First Reset Date (defined below) and in certain other circumstances prior to the Series A First Reset Date. The Series B Preferred Stock may be redeemed at the option of the Company at any time after the Series B First Reset Date (defined below) and in certain other circumstances prior to the Series B First Reset Date. The Series C Preferred Stock may be redeemed at the option of the Company at any time after the Series C First Reset Date (defined below) and in certain other circumstances prior to the Series C First Reset Date.

Dividends

Common Stock Dividends

In November 2018, Vistra announced the Board adopted a dividend program which we initiated in the first quarter of 2019. Each dividend under the program is 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, Vistra's results of operations, financial condition and liquidity, Delaware law and any contractual limitations. Quarterly dividends paid per share of common stock for the years ended December 31, 2023, 2022 and 2021 are reflected in the table below.

Year Ended December 31, 2023			Year Ended December 31, 2022			Year
Board Declaration Date	**Payment Date**	**Per Share Amount**	**Board Declaration Date**	**Payment Date**	**Per Share Amount**	**Board Declaration Date**
February 2023	March 2023	$ 0.198	February 2022	March 2022	$ 0.170	February 2021
May 2023	June 2023	$ 0.204	May 2022	June 2022	$ 0.177	April 2021
August 2023	September 2023	$ 0.206	July 2022	September 2022	$ 0.184	July 2021
November 2023	December 2023	$ 0.213	October 2022	December 2022	$ 0.193	October 2021

In February 2024, the Board declared a quarterly dividend of $0.215 per share of common stock that will be paid in March 2024.

Preferred Stock Dividends

The annual dividend rate on each share of Series A Preferred Stock is 8.0% from the Series A Issuance Date to, but excluding October 15, 2026 (Series A First Reset Date). On and after the Series A First Reset Date, the dividend rate on each share of Series A Preferred Stock shall equal the five-year U.S. Treasury rate as of the most recent reset dividend determination date (subject to a floor of 1.07%), plus a spread of 6.93% per annum. The Series A Preferred Stock has a liquidation preference of $1,000 per share, plus accumulated but unpaid dividends. Cumulative cash dividends on the Series A Preferred Stock are payable semiannually, in arrears, on each April 15 and October 15, commencing on April 15, 2022, when, as and if declared by the Board.

The annual dividend rate on each share of Series B Preferred Stock is 7.0% from the Series B Issuance Date to, but excluding December 15, 2026 (Series B First Reset Date). On and after the Series B First Reset Date, the dividend rate on each share of Series B Preferred Stock shall equal the five-year U.S. Treasury rate as of the most recent reset dividend determination date (subject to a floor of 1.26%), plus a spread of 5.74% per annum. The Series B Preferred Stock has a liquidation preference of $1,000 per share, plus accumulated but unpaid dividends. Cumulative cash dividends on the Series B Preferred Stock are payable semiannually, in arrears, on each June 15 and December 15, commencing on June 15, 2022, when, as and if declared by the Board.

The annual dividend rate on each share of Series C Preferred Stock is 8.875% from the Series C Issuance Date to, but excluding January 15, 2029 (Series C First Reset Date). On and after the Series C First Reset Date, the dividend rate on each share of Series C Preferred Stock shall equal the five-year U.S. Treasury rate as of the most recent reset dividend determination date (subject to a floor of 3.83%), plus a spread of 5.045% per annum. The Series C Preferred Stock has a liquidation preference of $1,000 per share, plus accumulated but unpaid dividends. Cumulative cash dividends on the Series C Preferred Stock are payable semiannually, in arrears, on each July 15 and January 15, commencing on July 15, 2024, when, as and if declared by the Board.

Semiannual dividends paid per share of each respective preferred stock series for the years ended December 31, 2023 and 2022 are reflected in the table below. Dividends payable are recorded on the Board declaration date.

Year Ended December 31, 2023				Year Ended December 31, 2022		
Board Declaration Date	Payment Date	Per Share Amount		Board Declaration Date	Payment Date	Per Share Amount
Series A Preferred Stock:				**Series A Preferred Stock:**		
February 2023	April 2023	$ 40.00		February 2022	April 2022	$ 40.00
August 2023	October 2023	$ 40.00		July 2022	October 2022	$ 40.00
Series B Preferred Stock:				**Series B Preferred Stock:**		
May 2023	June 2023	$ 35.00		May 2022	June 2022	$ 35.97
November 2023	December 2023	$ 35.00		October 2022	December 2022	$ 35.00

In February 2024, the Board declared a semi-annual dividend of $40.00 per share of Series A Preferred Stock that will be paid in April 2024.

Dividend Restrictions

The Vistra Operations Credit Agreement generally restricts the ability of Vistra Operations to make distributions to any direct or indirect parent unless such distributions are expressly permitted thereunder. As of December 31, 2023, Vistra Operations can distribute approximately $6.3 billion to Parent under the Vistra Operations Credit Agreement without the consent of any party. The amount that can be distributed by Vistra Operations to Parent was partially reduced by distributions made by Vistra Operations to Parent of approximately $1.625 billion, $1.775 billion and $405 million during the years ended December 31, 2023, 2022 and 2021, respectively. Additionally, Vistra Operations may make distributions to Parent in amounts sufficient for Parent to make any payments required under the TRA or the Tax Matters Agreement or, to the extent arising out of Parent's ownership or operation of Vistra Operations, to pay any taxes or general operating or corporate overhead expenses. As of December 31, 2023, all of the restricted net assets of Vistra Operations may be distributed to Parent.

In addition to the restrictions under the Vistra Operations Credit Agreement, under applicable Delaware law, we are only permitted to make distributions either out of "surplus," which is defined as the excess of our net assets above our capital (the aggregate par value of all outstanding shares of our stock), or out of net profits for the fiscal year in which the distribution is declared or the prior fiscal year.

Under the terms of the Series A Preferred Stock, the Series B Preferred Stock, and the Series C Preferred Stock, unless full cumulative dividends have been or contemporaneously are being paid or declared and a sum sufficient for the payment thereof set apart for payment on all outstanding Series A Preferred Stock (and any parity securities), Series B Preferred Stock (and any parity securities), and Series C Preferred Stock (and any parity securities), respectively, with respect to dividends through the most recent dividend payment dates, (i) no dividend may be declared or paid or set apart for payment on any junior security (other than a dividend payable solely in junior securities with respect to both dividends and the liquidation, winding-up and dissolution of our affairs), including our common stock, and (ii) we may not redeem, purchase or otherwise acquire any parity security or junior security, including our common stock, in each case subject to certain exceptions as described in the certificate of designation of the Series A Preferred Stock, the Series B Preferred Stock, and the Series C Preferred Stock, respectively.

Accumulated Other Comprehensive Income

During the years ended December 31, 2023, 2022 and 2021, we recorded changes in the funded status of our pension and other postretirement employee benefit liability totaling $5 million, $(23) million and $(24) million, respectively. During the years ended December 31, 2023, 2022 and 2021, $(4) million, zero and $(8) million respectively was reclassified from accumulated other comprehensive income and reported in other deductions.

Warrants

At the Dynegy Merger Date, the Company entered into an agreement whereby the holder of each outstanding warrant previously issued by Dynegy would be entitled to receive, upon paying an exercise price of $35.00 (subject to adjustment from time to time), the number of shares of Vistra common stock that such holder would have been entitled to receive if it had held one share of Dynegy common stock at the closing of the Dynegy Merger, or 0.652 shares of Vistra common stock. The warrants were included in equity based on their fair value at the Dynegy Merger Date. As of December 31, 2023, total warrants outstanding was approximately nine million, and they expired in February 2024.

16. FAIR VALUE MEASUREMENTS

We utilize several different valuation techniques to measure the fair value of assets and liabilities, relying primarily on the market approach of using prices and other market information for identical and/or comparable assets and liabilities for those items that are measured on a recurring basis. We use a mid-market valuation convention (the mid-point price between bid and ask prices) as a practical expedient to measure fair value for the majority of our assets and liabilities and use valuation techniques to maximize the use of observable inputs and minimize the use of unobservable inputs. Our valuation policies and procedures were developed, maintained and validated by a centralized risk management group that reports to the Vistra Chief Financial Officer.

Fair value measurements of derivative assets and liabilities incorporate an adjustment for credit-related nonperformance risk. These nonperformance risk adjustments take into consideration master netting arrangements, credit enhancements and the credit risks associated with our credit standing and the credit standing of our counterparties (see Note 17 for additional information regarding credit risk associated with our derivatives). We utilize credit ratings and default rate factors in calculating these fair value measurement adjustments.

We categorize our assets and liabilities recorded at fair value based upon the following fair value hierarchy:

- Level 1 valuations use quoted prices in active markets for identical assets or liabilities that are accessible at the measurement date. Our Level 1 assets and liabilities include CME or ICE (electronic commodity derivative exchanges) futures and options transacted through clearing brokers for which prices are actively quoted. We report the fair value of CME and ICE transactions without taking into consideration margin deposits, with the exception of certain margin amounts related to changes in fair value on certain CME transactions that are legally characterized as settlement of derivative contracts rather than collateral.

- Level 2 valuations utilize over-the-counter broker quotes, quoted prices for similar assets or liabilities that are corroborated by correlations or other mathematical means, and other valuation inputs such as interest rates and yield curves observable at commonly quoted intervals. We attempt to obtain multiple quotes from brokers that are active in the markets in which we participate and require at least one quote from two brokers to determine a pricing input as observable. The number of broker quotes received for certain pricing inputs varies depending on the depth of the trading market, each individual broker's publication policy, recent trading volume trends and various other factors.

- Level 3 valuations use unobservable inputs for the asset or liability. Unobservable inputs are used to the extent observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at the measurement date. We use the most meaningful information available from the market combined with internally developed valuation methodologies to develop our best estimate of fair value. Significant unobservable inputs used in the valuation models include volatility curves, correlation curves, illiquid pricing delivery periods and locations and credit-related nonperformance risk assumptions. These inputs and valuation models are developed and maintained by employees trained and experienced in market operations and fair value measurements and validated by the Company's risk management group.

The fair value input hierarchy level to which an asset or liability measurement in its entirety falls is determined based on the lowest level input that is significant to the measurement.

Assets and liabilities measured at fair value on a recurring basis consisted of the following at the respective balance sheet dates shown below:

	December 31, 2023					
	Level 1	Level 2	Level 3 (a)	Reclass (b)	Total	Level 1
Assets:						
Commodity contracts	$ 2,886	$ 628	$ 630	$ 14	$ 4,158	$ 3,512
Interest rate swaps	—	64	—	—	64	—
Nuclear decommissioning trust – equity securities (c)	638	—	—	—	638	532
Nuclear decommissioning trust – debt securities (c)	—	734	—	—	734	—
Sub-total	$ 3,524	$ 1,426	$ 630	$ 14	5,594	$ 4,044
Assets measured at net asset value (d):						
Nuclear decommissioning trust – equity securities (c)					579	
Total assets					$ 6,173	
Liabilities:						
Commodity contracts	$ 3,815	$ 1,395	$ 1,674	$ 14	$ 6,898	$ 5,297
Interest rate swaps	—	48	—	—	48	—
Total liabilities	$ 3,815	$ 1,443	$ 1,674	$ 14	$ 6,946	$ 5,297

(a) See table below for description of Level 3 assets and liabilities.
(b) Fair values for each level are determined on a contract basis, but certain contracts are in both an asset and a liability position. This reclassification represents the adjustment needed to reconcile to the gross amounts presented on our consolidated balance sheet.
(c) The nuclear decommissioning trust investment is included in the investments line in our consolidated balance sheets. See Note 22.
(d) The fair value amounts presented in this line are intended to permit reconciliation of the fair value hierarchy to the amounts presented in our consolidated balance sheets. Certain investments measured at fair value using the net asset value per share (or its equivalent) have not been classified in the fair value hierarchy. Net asset value as a practical expedient is the classification used for assets that do not have readily determinable fair values.

Commodity contracts consist primarily of natural gas, electricity, coal and emissions agreements and include financial instruments entered into for economic hedging purposes as well as physical contracts that have not been designated as NPNS. Interest rate swaps are used to reduce exposure to interest rate changes by converting floating-rate interest to fixed rates. See Note 17 for further discussion regarding derivative instruments.

Nuclear decommissioning trust assets represent securities held for the purpose of funding the future retirement and decommissioning of our nuclear generation facility. These investments include equity, debt and other fixed-income securities consistent with investment rules established by the NRC and the PUCT.

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The following tables present the fair value of the Level 3 assets and liabilities by major contract type and the significant unobservable inputs used in the valuations at December 31, 2023 and 2022:

	December 31, 2023					
	Fair Value					
Contract Type (a)	Assets	Liabilities	Total	Valuation Technique	Significant Unobservable Input	
Electricity purchases and sales	$ 449	$ (1,273)	$ (824)	Income Approach	Hourly price curve shape (c)	$ —
					Illiquid delivery periods for hub power prices and Heat Rates (d)	$ 30
Options	1	(237)	(236)	Option Pricing Model	Natural gas to power correlation (e)	10
					Power and natural gas volatility (e)	10
Financial transmission rights	157	(34)	123	Market Approach (f)	Illiquid price differences between settlement points (g)	$ (85)
Natural gas	9	(112)	(103)	Income Approach	Natural gas basis (h)	$ —
					Illiquid delivery periods (i)	$ —
Other (j)	14	(18)	(4)			
Total	$ 630	$ (1,674)	$ (1,044)			

	December 31, 2022					
	Fair Value					
Contract Type (a)	Assets	Liabilities	Total	Valuation Technique	Significant Unobservable Input	
Electricity purchases and sales	$ 603	$ (1,332)	$ (729)	Income Approach	Hourly price curve shape (c)	$ —
					Illiquid delivery periods for hub power prices and Heat Rates (d)	$ 25
Options	—	(483)	(483)	Option Pricing Model	Natural gas to power correlation (e)	10
					Power and natural gas volatility (e)	5
Financial transmission rights	132	(31)	101	Market Approach (f)	Illiquid price differences between settlement points (g)	$ (35)
Natural gas	20	(155)	(135)	Income Approach	Natural gas basis (h)	$ —
Other (j)	36	(9)	27			
Total	$ 791	$ (2,010)	$ (1,219)			

(a) Electricity purchase and sales contracts include power and Heat Rate positions in ERCOT, PJM, ISO-NE, NYISO, MISO and CAISO regions. The forward purchase contracts (swaps and options) used to hedge electricity price differences between settlement points are referred to as congestion revenue rights (CRRs) in ERCOT and financial transmission rights (FTRs) in PJM, ISO-NE, NYISO and MISO regions. Natural gas includes swaps and forward contracts. Options consist of physical electricity options, spread options and natural gas options.

(b) The range of the inputs may be influenced by factors such as time of day, delivery period, season and location. The average represents the arithmetic average of the underlying inputs and is not weighted by the related fair value or notional amount.

(c) Primarily based on the historical range of forward average hourly ERCOT North Hub and ERCOT South and West Zone prices.
(d) Primarily based on historical forward ERCOT and PJM power prices and ERCOT Heat Rate variability.
(e) Primarily based on the historical forward correlation and volatility within ERCOT and PJM.
(f) While we use the market approach, there is insufficient market data to consider the valuation liquid.
(g) Primarily based on the historical price differences between settlement points within ERCOT hubs and load zones.
(h) Primarily based on the historical forward PJM and Northeast natural gas basis prices and fixed prices.
(i) Primarily based on the historical forward natural gas fixed prices.
(j) Other includes contracts for coal and environmental allowances.

There were no transfers between Level 1 and Level 2 of the fair value hierarchy for the years ended December 31, 2023, 2022 and 2021. See the table below for discussion of transfers between Level 2 and Level 3 for the years ended December 31, 2023, 2022 and 2021.

The following table presents the changes in fair value of the Level 3 assets and liabilities for the years ended December 31, 2023, 2022 and 2021.

	Year Ended December 31,		
	2023	2022	2021
Net asset (liability) balance at beginning of period	$ (1,219)	$ (360)	$ 22
Total unrealized valuation losses	(765)	(1,382)	(53)
Purchases, issuances and settlements (a):			
Purchases	222	185	114
Issuances	(30)	(62)	(36)
Settlements	136	345	(314)
Transfers into Level 3 (b)	(48)	(30)	(2)
Transfers out of Level 3 (b)	660	85	(91)
Net change (c)	175	(859)	(382)
Net (liability) balance at end of period	$ (1,044)	$ (1,219)	$ (360)
Unrealized valuation losses relating to instruments held at end of period	$ (676)	$ (977)	$ (364)

(a) Settlements reflect reversals of unrealized mark-to-market valuations previously recognized in net income. Purchases and issuances reflect option premiums paid or received, including CRRs and FTRs.
(b) Includes transfers due to changes in the observability of significant inputs. All Level 3 transfers during the periods presented are in and out of Level 2. For the year ended December 31, 2023, transfers into Level 3 primarily consist of power derivatives where forward pricing inputs have become unobservable and transfers out of Level 3 primarily consist of power and coal derivatives where forward pricing inputs have become observable. For the year ended December 31, 2022, transfers into Level 3 primarily consist of power and coal derivatives where forward pricing inputs have become unobservable and transfers out of Level 3 primarily consist of power, natural gas, and coal derivatives where forward pricing inputs have become observable.
(c) Activity excludes change in fair value in the month positions settle. Substantially all changes in values of commodity contracts are reported as operating revenues in our consolidated statements of operations.

17. COMMODITY AND OTHER DERIVATIVE CONTRACTUAL ASSETS AND LIABILITIES

We transact in derivative instruments, such as options, swaps, futures and forward contracts, to manage our exposure to commodity price and interest rate volatility. Although we do engage in economic hedging activities to manage our exposure related to commodity price fluctuations through the use of financial and physical derivative contracts, we have no derivative positions accounted for as cash flow or fair value hedges as of December 31, 2023 and 2022. All changes in the fair values of our derivative contracts are recognized as gains or losses in the earnings of the periods in which they occur. See Note 16 for a discussion of the fair value of derivatives.

Commodity Hedging and Trading Activity

We utilize natural gas and electricity derivatives to reduce exposure to changes in electricity prices primarily to hedge future revenues from electricity sales from our generation assets and to hedge future purchased power costs for our retail operations. We also utilize short-term electricity, natural gas, coal and emissions derivative instruments for fuel hedging and other purposes. Counterparties to these transactions include energy companies, financial institutions, electric utilities, independent power producers, fuel oil and natural gas producers, local distribution companies and energy marketing companies. Unrealized gains and losses arising from changes in the fair value of derivative instruments as well as realized gains and losses upon settlement of the instruments are reported in our consolidated statements of operations in operating revenues and fuel, purchased power costs and delivery fees.

Interest Rate Swaps

Interest rate swap agreements are used to reduce exposure to interest rate changes by converting floating-rate interest rates to fixed rates, thereby hedging future interest costs and related cash flows. Unrealized gains and losses arising from changes in the fair value of the swaps as well as realized gains and losses upon settlement of the swaps are reported in our consolidated statements of operations in interest expense and related charges. See Note 12 for details on our interest rate swaps outstanding as of December 31, 2023.

Financial Statement Effects of Derivatives

Substantially all derivative contractual assets and liabilities are accounted for under mark-to-market accounting consistent with accounting standards related to derivative instruments and hedging activities. The following tables provide detail of derivative contractual assets and liabilities as reported in our consolidated balance sheets at December 31, 2023 and 2022. Derivative asset and liability totals represent the net value of the contract, while the balance sheet totals represent the gross value of the contract.

	December 31, 2023				
	Derivative Assets		Derivative Liabilities		
	Commodity Contracts	Interest Rate Swaps	Commodity Contracts	Interest Rate Swaps	Total
Current assets	$ 3,585	$ 53	$ 7	$ —	$ 3,645
Noncurrent assets	565	11	1	—	577
Current liabilities	(1)	—	(5,233)	(24)	(5,258)
Noncurrent liabilities	(5)	—	(1,659)	(24)	(1,688)
Net assets (liabilities)	$ 4,144	$ 64	$ (6,884)	$ (48)	$ (2,724)

	December 31, 2022				
	Derivative Assets		Derivative Liabilities		
	Commodity Contracts	Interest Rate Swaps	Commodity Contracts	Interest Rate Swaps	Total
Current assets	$ 4,442	$ 92	$ 4	$ —	$ 4,538
Noncurrent assets	656	43	3	—	702
Current liabilities	(1)	—	(6,562)	(47)	(6,610)
Noncurrent liabilities	(5)	—	(1,685)	(36)	(1,726)
Net assets (liabilities)	$ 5,092	$ 135	$ (8,240)	$ (83)	$ (3,096)

The following table presents the pre-tax effect of derivative gains (losses) on net income, including realized and unrealized effects. Amount represents changes in fair value of positions in the derivative portfolio during the period, as realized amounts related to positions settled are assumed to equal reversals of previously recorded unrealized amounts.

	Year Ended December 31,		
Derivative (consolidated statements of operations presentation)	2023	2022	2021
Commodity contracts (Operating revenues) (a)	$ (758)	$ (4,103)	$ (1,196)
Commodity contracts (Fuel, purchased power costs and delivery fees) (b)	(395)	375	732
Interest rate swaps (Interest expense and related charges) (c)	42	234	81
Net gain (loss)	$ (1,111)	$ (3,494)	$ (383)

(a) For the year ended December 31, 2023, includes unrealized net gains from mark-to-market valuations of commodity positions of $714 million. For the years ended December 31, 2022 and 2021, includes unrealized net losses from mark-to-market valuations of commodity positions of $2.163 billion and $1.191 billion, respectively.

(b) For the years ended December 31, 2023 and 2022, includes unrealized net losses from mark-to-market valuations of commodity positions of $224 million and $347 million, respectively. For the year ended December 31, 2021, includes unrealized net gains from mark-to-market valuations of commodity positions of $432 million.

(c) For the year ended December 31, 2023, includes unrealized net losses on mark-to-market valuations of interest rate swaps of $36 million. For the years ended December 31, 2022 and 2021, includes unrealized gains on mark-to-market valuations of interest rate swaps of $250 million and $134 million, respectively.

Balance Sheet Presentation of Derivatives

We elect to report derivative assets and liabilities in our consolidated balance sheets on a gross basis without taking into consideration netting arrangements we have with counterparties to those derivatives. We maintain standardized master netting agreements with certain counterparties that allow for the right to offset assets and liabilities and collateral in order to reduce credit exposure between us and the counterparty. These agreements contain specific language related to margin requirements, monthly settlement netting, cross-commodity netting and early termination netting, which is negotiated with the contract counterparty.

Generally, margin deposits that contractually offset these derivative instruments are reported separately in our consolidated balance sheets, with the exception of certain margin amounts related to changes in fair value on CME transactions that are legally characterized as settlement of forward exposure rather than collateral. Margin deposits received from counterparties are primarily used for working capital or other general corporate purposes.

The following tables reconcile our derivative assets and liabilities on a contract basis to net amounts after taking into consideration netting arrangements with counterparties and financial collateral:

	December 31, 2023				
	Derivative Assets and Liabilities	Offsetting Instruments (a)	Cash Collateral (Received) Pledged (b)	Net Amounts	Derivative Assets and Liabilities
Derivative assets:					
Commodity contracts	$ 4,144	$ (3,519)	$ (26)	$ 599	$ 5,092
Interest rate swaps	64	(28)	—	36	135
Total derivative assets	4,208	(3,547)	(26)	635	5,227
Derivative liabilities:					
Commodity contracts	(6,884)	3,519	970	(2,395)	(8,240)
Interest rate swaps	(48)	28	—	(20)	(83)
Total derivative liabilities	(6,932)	3,547	970	(2,415)	(8,323)
Net amounts	$ (2,724)	$ —	$ 944	$ (1,780)	$ (3,096)

(a) Amounts presented exclude trade accounts receivable and payable related to settled financial instruments.
(b) Represents cash amounts received or pledged pursuant to a master netting arrangement, including fair value-based margin requirements, and, to a lesser extent, initial margin requirements.

Derivative Volumes

The following table presents the gross notional amounts of derivative volumes by commodity, excluding those derivatives that qualified for the NPNS or other scope exceptions permitted by ASC 815, *Derivatives and Hedging* as of December 31, 2023 and 2022:

Derivative type	December 31, 2023	December 31, 2022	Unit of Measure
	Notional Volume		
Natural gas (a)	5,335	6,007	Million MMBtu
Electricity	800,001	754,762	GWh
Financial transmission rights (b)	250,895	225,845	GWh
Coal	35	48	Million U.S. tons
Fuel oil	3	105	Million gallons
Emissions	24	40	Million U.S. tons
Renewable energy certificates	29	31	Million certificates
Interest rate swaps – variable/fixed (c)	$ 5,225	$ 6,720	Million U.S. dollars
Interest rate swaps - fixed/variable (c)	$ 1,300	$ 2,120	Million U.S. dollars

(a) Represents gross notional forward sales, purchases and options transactions, locational basis swaps and other natural gas transactions.
(b) Represents gross forward purchases associated with instruments used to hedge electricity price differences between settlement points within regions.
(c) Includes notional amounts of interest rate swaps with maturity dates through December 2030.

Credit Risk-Related Contingent Features of Derivatives

Our derivative contracts may contain certain credit risk-related contingent features that could trigger liquidity requirements in the form of cash collateral, letters of credit or some other form of credit enhancement. Certain of these agreements require the posting of collateral if our credit rating is downgraded by one or more credit rating agencies or include cross-default contractual provisions that could result in the settlement of such contracts if there was a failure under other financing arrangements related to payment terms or other covenants.

The following table presents the commodity derivative liabilities subject to credit risk-related contingent features that are not fully collateralized:

	December 31,	
	2023	2022
Fair value of derivative contract liabilities (a)	$ (1,890)	$ (1,934)
Offsetting fair value under netting arrangements (b)	692	899
Cash collateral and letters of credit	854	253
Liquidity exposure	$ (344)	$ (782)

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(a) Excludes fair value of contracts that contain contingent features that do not provide specific amounts to be posted if features are triggered, including provisions that generally provide the right to request additional collateral (material adverse change, performance assurance and other clauses).

(b) Amounts include the offsetting fair value of in-the-money derivative contracts and net accounts receivable under master netting arrangements.

Concentrations of Credit Risk Related to Derivatives

We have concentrations of credit risk with the counterparties to our derivative contracts. As of December 31, 2023, total credit risk exposure to all counterparties related to derivative contracts totaled $4.681 billion (including associated accounts receivable). The net exposure to those counterparties totaled $727 million at December 31, 2023 after taking into effect netting arrangements, setoff provisions and collateral, with the largest net exposure totaling $235 million. As of December 31, 2023, the credit risk exposure to the banking and financial sector represented 80% of the total credit risk exposure and 28% of the net exposure.

Exposure to banking and financial sector counterparties is considered to be within an acceptable level of risk tolerance because all of this exposure is with counterparties with investment grade credit ratings. However, this concentration increases the risk that a default by any of these counterparties would have a material effect on our financial condition, results of operations and liquidity. The transactions with these counterparties contain certain provisions that would require the counterparties to post collateral in the event of a material downgrade in their credit rating.

We maintain credit risk policies with regard to our counterparties to minimize overall credit risk. These policies authorize specific risk mitigation tools including, but not limited to, use of standardized master agreements that allow for netting of positive and negative exposures associated with a single counterparty. Credit enhancements such as parent guarantees, letters of credit, surety bonds, liens on assets and margin deposits are also utilized. Prospective material changes in the payment history or financial condition of a counterparty or downgrade of its credit quality result in the reassessment of the credit limit with that counterparty. The process can result in the subsequent reduction of the credit limit or a request for additional financial assurances. An event of default by one or more counterparties could subsequently result in termination-related settlement payments that reduce available liquidity if amounts are owed to the counterparties related to the derivative contracts or delays in receipts of expected settlements if the counterparties owe amounts to us.

18. PENSION AND OTHER POSTRETIREMENT EMPLOYEE BENEFITS (OPEB) PLANS

Vistra is the plan sponsor of the Vistra Retirement Plan (the Retirement Plan), which provides benefits to eligible employees of its subsidiaries. Oncor is a participant in the Retirement Plan. As Vistra accounts for its interests in the Retirement Plan as a multiple employer plan, only Vistra's share of the plan assets and obligations are reported in the pension benefit information presented below. After amendments in 2012, employees in the Retirement Plan now consist entirely of participants who were active and retired collective bargaining unit employees. The Retirement Plan is a qualified defined benefit pension plan under Section 401(a) of the Internal Revenue Code of 1986, as amended (Code), and is subject to the provisions of ERISA. The Retirement Plan provides benefits to participants under one of two formulas: (i) a Cash Balance Formula under which participants earn monthly contribution credits based on their compensation and a combination of their age and years of service, plus monthly interest credits or (ii) a Traditional Retirement Plan Formula based on years of service and the average earnings of the three years of highest earnings. Under the Cash Balance Formula, future increases in earnings will not apply to prior service costs. It is our policy to fund the Retirement Plan assets only to the extent required under existing federal regulations.

Vistra and our participating subsidiaries offer other postretirement employee benefits (OPEB) in the form of certain health care and life insurance benefits to eligible retirees and their eligible dependents. The retiree contributions required for such coverage vary based on a formula depending on the retiree's age and years of service.

Effective January 1, 2018, Vistra entered into a contractual arrangement with Oncor whereby the costs associated with providing OPEB coverage for certain retirees (Split Participants) whose employment included service with both the regulated businesses of Oncor (or its predecessors) and the non-regulated businesses of Vistra (or its predecessors) are split between Oncor and Vistra. As Vistra accounts for its interest in this OPEB plan as a multiple employer plan, only Vistra's share of the plan assets and obligations are reported in the OPEB information presented below. In addition, Vistra is the sponsor of OPEB plans that certain EFH Corp. and Dynegy retirees participate in.

Pension and OPEB Costs

	Year Ended December 31,		
	2023	2022	2021
Pension costs	$ 9	$ 2	$ 6
OPEB costs	5	4	8
Total benefit costs recognized as expense	$ 14	$ 6	$ 14

Market-Related Value of Assets Held in Pension Benefit Trusts

We use the calculated value method to determine the market-related value of the assets held in the trust for purposes of calculating pension costs. We include all gains or losses in the market-related value of assets over a rolling four-year period. Each year, 25% of such gains and losses for the current year and for each of the preceding three years is included in the market-related value. Each year, the market-related value of assets is increased for contributions to the plan and investment income and is decreased for benefit payments and expenses for that year.

Detailed Information Regarding Pension Plans and OPEB Benefits

The following information is based on a December 31, 2023, 2022 and 2021 measurement dates:

	Retirement Plan			OPEB Plans		
	Year Ended December 31,			Year Ended December 31,		
	2023	2022	2021	2023	2022	2021
Assumptions Used to Determine Net Periodic Pension and Benefit Cost:						
Discount rate	5.16 %	2.84 %	2.50 %	5.18 %	2.87 %	2.51 %
Expected rate of compensation increase	3.79 %	3.49 %	3.41 %			
Interest crediting rate for cash balance	3.00 %	3.00 %	3.00 %			
Expected return on plan assets (Vistra Plan)	5.85 %	4.24 %	3.77 %			
Expected return on plan assets (Dynegy Plan)	5.85 %	4.77 %	4.42 %			
Expected return on plan assets (EEI Plan)	— %	4.92 %	4.72 %			
Expected return on plan assets (EEI Union)				3.89 %	3.92 %	6.79 %
Expected return on plan assets (EEI Salaried)				4.85 %	3.41 %	2.95 %
Components of Net Pension and Benefit Cost:						
Service cost	$ 3	$ 4	$ 5	$ 1	$ 1	$ 1
Interest cost	21	17	16	5	4	4
Expected return on assets	(18)	(19)	(18)	(1)	(1)	(2)
Amortization of unrecognized amounts, net	3	—	3	—	—	5
Net periodic pension and OPEB cost	$ 9	$ 2	$ 6	$ 5	$ 4	$ 8
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income:						
Net (gain) loss	$ 7	$ (16)	$ (27)	$ —	$ (22)	$ (10)
Prior service (credit) cost	(6)	9	—	—	—	(2)
Curtailment and settlements	—	—	(2)	—	—	
Total						

Net Actuarial Gains (Losses)

Retirement Plan

For the year ended December 31, 2023, the net actuarial loss of $5 million that occurred for the pension plans during 2023 was a result of losses attributable to decreasing discount rates due to changes in the corporate bond markets and losses attributable to actuarial assumption updates to reflect current market conditions, plan experience different than expected, and settlements, partially offset by a gain attributable to actual asset performance exceeding expectations. The Dynegy Pension Plan was amended during 2023 to extend the lump sum interest rates from calendar year 2022 through 2024 and provide in-service distributions for certain eligible employees as of December 31, 2022. As a result, the pension obligation increased by $1 million and a prior service cost was created to be amortized over 2 years.

For the year ended December 31, 2022, the net actuarial gain of $16 million was driven by gains attributable to increasing discount rates due to changes in the corporate bond markets, gains attributable to actuarial assumption updates to reflect current market conditions and plan experience different than expected, partially offset by losses attributable to actual asset performance falling short of expectations and settlements.

For the year ended December 31, 2021, the net actuarial gain of $24 million was driven by gains attributable to increasing discount rates due to changes in the corporate bond markets and gains attributable to actual asset performance exceeding expectations, partially offset by losses attributable to demographic assumption updates to reflect recent plan experience, actuarial assumption updates to reflect current market conditions, plan amendments, settlements and plan experience different than expected.

OPEB Plans

For the year ended December 31, 2023, the immaterial net actuarial loss that occurred for the OPEB plans during 2023 was a result of losses attributable to decreasing discount rates due to changes in the corporate bond markets, partially offset by gains attributable to plan experience different than expected, updates to health care assumptions, and actual asset performance exceeding expectations.

For the year ended December 31, 2022, the net actuarial gain of $22 million was driven by gains attributable to increasing discount rates due to changes in the corporate bond markets, plan experience different than expected and updates to health care assumptions, partially offset by losses attributable to actual asset performance falling short of expectations.

For the period ended December 31, 2021, the net actuarial gain of $7 million was driven by gains attributable to increasing discount rates due to changes in the corporate bond markets, plan experience different than expected, updates to health care claims and trend assumptions and actual asset performance exceeding expectations, partially offset by losses attributable to demographic assumption updates and life expectancy updates.

	Retirement Plan		OPEB Plans	
	Year Ended December 31,		Year Ended December 31,	
	2023	2022	2023	2022
Change in Pension and Postretirement Benefit Obligations:				
Projected benefit obligation at beginning of period	$ 449	$ 605	$ 110	$ 146
Service cost	3	4	1	1
Interest cost	21	17	5	4
Participant contributions	—	—	3	2
Plan amendments	1	9	—	—
Actuarial (gain) loss	10	(113)	1	(30)
Benefits paid	(59)	(73)	(12)	(13)
Projected benefit obligation at end of year	$ 425	$ 449	$ 108	$ 110
Accumulated benefit obligation at end of year	$ 422	$ 447	$ —	$ —
Change in Plan Assets:				
Fair value of assets at beginning of period	$ 320	$ 470	$ 29	$ 39
Employer contributions	—	—	9	9
Participant contributions	—	—	3	2
Actual gain (loss) on assets	24	(77)	2	(6)
Transfers	—	—	(19)	(2)
Benefits paid	(59)	(73)	(12)	(13)
Fair value of assets at end of year	$ 285	$ 320	$ 12	$ 29
Funded Status:				
Projected benefit obligation	$ (425)	$ (449)	$ (108)	$ (110)
Fair value of assets	285	320	12	29
Funded status at end of year	$ (140)	$ (129)	$ (96)	$ (81)
Amounts Recognized in the Balance Sheet Consist of:				
Investments	$ —	$ —	$ 3	$ 20
Other current liabilities	—	—	(9)	(8)
Other noncurrent liabilities	(140)	(129)	(90)	(93)
Net liability recognized	$ (140)	$ (129)	$ (96)	$ (81)
Amounts Recognized in Accumulated Other Comprehensive Income Consist of:				
Net actuarial (gain) loss	$ 4	$ (4)	$ (15)	$ (15)
Prior services cost	3	9	1	1
Net (income) loss and prior service cost	$ 7	$ 5	$ (14)	$ (14)

Fair Value Measurement of Pension and OPEB Plan Assets

Retirement Plan

As of December 31, 2023 and 2022, all of the Retirement Plan assets were measured at fair value using the net asset value per share (or its equivalent) except as noted and consisted of the following:

	December 31, 2023	December 31, 2022
Asset Category:		
Interest-bearing cash (a)	$ —	$ 2
Cash commingled trusts	4	4
Equity securities:		
Global equities	82	80
Fixed income securities:		
Corporate bonds (b)	82	107
Government bonds	54	44
Other (c)	18	24
Real estate	28	43
Hedge funds	17	16
Total assets measured at net asset value	$ 285	$ 320

(a) Interest -bearing cash is classified as Level 2.
(b) Substantially all corporate bonds are rated investment grade by a major ratings agency such as Moody's.
(c) Consists primarily of high-yield bonds, emerging market debt, bank loans, securitized bonds and private investment grade fixed income.

OPEB Plans

As of December 31, 2023 and 2022, the Vistra OPEB plan assets measured at fair value totaled $12 million and $29 million, respectively. At December 31, 2023 and 2022, assets consisted of $9 million and $28 million, respectively, of comingled funds valued at net asset value and $3 million and $1 million, respectively, of municipal bond and cash equivalent mutual funds classified as Level 1.

Pension Plans with Projected Benefit Obligations (PBO) and Accumulated Benefit Obligations (ABO) in Excess of Plan Assets

The following table provides information regarding pension plans with PBO and ABO in excess of the fair value of plan assets.

	December 31, 2023	December 31, 2022
Pension Plans with PBO and ABO in Excess of Plan Assets:		
Projected benefit obligations	$ 425	$ 449
Accumulated benefit obligation	$ 422	$ 447
Plan assets	$ 285	$ 320

Retirement Plan Investment Strategy and Asset Allocations

Our investment objective for the Retirement Plan is to invest in a suitable mix of assets to meet the future benefit obligations at an acceptable level of risk, while minimizing the volatility of contributions. Fixed income securities held primarily consist of corporate bonds from a diversified range of companies, U.S. Treasuries and agency securities and money market instruments. Equity securities are held to enhance returns by participating in a wide range of investment opportunities. International equity securities are used to further diversify the equity portfolio and may include investments in both developed and emerging markets. Real estate, hedge funds and credit strategies (primarily high yield bonds and emerging market debt) provide additional portfolio diversification and return potential.

The target asset allocation ranges of pension plan investments by asset category are as follows:

	Target Allocation Ranges	
Asset Category:	**Vistra Plan**	**Dynegy Plan**
Fixed income securities	50 % - 70%	40 % - 50%
Global equity securities	20 % - 28%	28 % - 38%
Real estate	6 % - 10%	7 % - 15%
Credit strategies	2 % - 6%	4 % - 8%
Hedge funds	2 % - 6%	4 % - 8%

Retirement Plan Expected Long-Term Rate of Return on Assets Assumption

The Retirement Plan strategic asset allocation is determined in conjunction with the plan's advisors and utilizes a comprehensive Asset-Liability modeling approach to evaluate potential long-term outcomes of various investment strategies. The study incorporates long-term rate of return assumptions for each asset class based on historical and future expected asset class returns, current market conditions, rate of inflation, current prospects for economic growth, and taking into account the diversification benefits of investing in multiple asset classes and potential benefits of employing active investment management.

	Retirement Plan Expected Long-Term Rate of Return	
Asset Class:	**Vistra Plan**	**Dynegy Plan**
Fixed income securities	5.3 %	5.1 %
Global equity securities	7.4 %	7.4 %
Real estate	5.5 %	5.5 %
Credit strategies	6.5 %	6.5 %
Hedge funds	7.3 %	7.3 %
Weighted average	5.9 %	6.1 %

Benefit Plan Assumed Health Care Cost Trend Rates

The following tables provide information regarding the assumed health care cost trend rates.

	December 31,	
	2023	**2022**
Assumed Health Care Cost Trend Rates-Not Medicare Eligible:		
Health care cost trend rate assumed for next year	7.00 %	6.80 %
Rate to which the cost trend is expected to decline (the ultimate trend rate)	4.50 %	4.50 %
Year that the rate reaches the ultimate trend rate	2033	2032
Assumed Health Care Cost Trend Rates-Medicare Eligible:		
Health care cost trend rate assumed for next year (Vistra Plan)	12.90 %	10.30 %
Health care cost trend rate assumed for next year (Split-Participant Plan)	12.30 %	10.00 %
Rate to which the cost trend is expected to decline (the ultimate trend rate)	4.50 %	4.50 %
Year that the rate reaches the ultimate trend rate	2033	2032

Significant Concentrations of Risk

The plans' investments are exposed to risks such as interest rate, capital market and credit risks. We seek to optimize return on investment consistent with levels of liquidity and investment risk which are prudent and reasonable, given prevailing capital market conditions and other factors specific to us. While we recognize the importance of return, investments will be diversified in order to minimize the risk of large losses unless, under the circumstances, it is clearly prudent not to do so. There are also various restrictions and guidelines in place including limitations on types of investments allowed and portfolio weightings for certain investment securities to assist in the mitigation of the risk of large losses.

Assumed Discount Rate

We selected the assumed discount rates using the Aon AA Above Median yield curve, which is based on corporate bond yields and at December 31, 2023 consisted of 509 corporate bonds with an average rating of AA using Moody's, S&P and Fitch ratings.

Contributions

Contributions to the Retirement Plan for the years ended December 31, 2023, 2022 and 2021 totaled zero, zero and $1 million, respectively, and contributions in 2024 are expected to total $14 million. OPEB plan funding for each of the years ended December 31, 2023, 2022 and 2021 totaled $9 million, and funding in 2024 is expected to total $9 million.

Future Benefit Payments

Estimated future benefit payments to beneficiaries are as follows:

	2024	2025	2026	2027	2028	2029-2033
Pension benefits	$ 52	$ 30	$ 36	$ 37	$ 29	$ 142
OPEB	$ 10	$ 9	$ 9	$ 9	$ 8	$ 37

Qualified Savings Plans

Our employees may participate in a qualified savings plan (the Thrift Plan). This plan is a participant-directed defined contribution plan intended to qualify under Section 401(a) of the Code and is subject to the provisions of ERISA. Under the terms of the Thrift Plan, employees who do not earn more than the IRS threshold compensation limit used to determine highly compensated employees may contribute, through pre-tax salary deferrals and/or after-tax payroll deductions, the lesser of 75% of their regular salary or wages or the maximum amount permitted under applicable law. Employees who earn more than such threshold may contribute from 1% to 20% of their regular salary or wages. Employer matching contributions are also made in an amount equal to 100% (75% for employees covered under the traditional formula in the Retirement Plan) of the first 6% of employee contributions. Employer matching contributions are made in cash and may be allocated by participants to any of the plan's investment options.

Aggregate employer contributions to the qualified savings plans totaled $33 million, $33 million and $34 million for the years ended December 31, 2023, 2022 and 2021, respectively.

19. STOCK-BASED COMPENSATION

Vistra 2016 Omnibus Incentive Plan

On the Effective Date, the Board adopted the 2016 Omnibus Incentive Plan (2016 Incentive Plan), under which an aggregate of 22,500,000 shares of our common stock were reserved for issuance as equity-based awards to our non-employee directors, employees, and certain other persons. Following approval of the Board and approval by the stockholders at the 2019 annual meeting of the Company, the 2016 Incentive Plan was amended to increase the maximum number of shares reserved for issuance under the 2016 Incentive Plan to 37,500,000. The Board or any committee duly authorized by the Board will administer the 2016 Incentive Plan and has broad authority under the 2016 Incentive Plan to, among other things: (a) select participants, (b) determine the types of awards that participants are to receive and the number of shares that are to be subject to such awards and (c) establish the terms and conditions of awards, including the price (if any) to be paid for the shares of the award. The types of awards that may be granted under the 2016 Incentive Plan include stock options, RSUs, restricted stock, performance awards and other forms of awards granted or denominated in shares of Vistra common stock, as well as certain cash-based awards.

If any stock option or other stock-based award granted under the 2016 Incentive Plan expires, terminates or is canceled for any reason without having been exercised in full, the number of shares of Vistra common stock underlying any unexercised award shall again be available for awards under the 2016 Incentive Plan. If any shares of restricted stock, performance awards or other stock-based awards denominated in shares of Vistra common stock awarded under the 2016 Incentive Plan are forfeited for any reason, the number of forfeited shares shall again be available for purposes of awards under the 2016 Incentive Plan. Any award under the 2016 Incentive Plan settled in cash shall not be counted against the maximum share limitation. No awards under the 2016 Incentive Plan have been settled in cash since the Effective Date.

As is customary in incentive plans of this nature, each share limit and the number and kind of shares available under the 2016 Incentive Plan and any outstanding awards, as well as the exercise or purchase price of awards, and performance targets under certain types of performance-based awards, are required to be adjusted in the event of certain reorganizations, mergers, combinations, recapitalizations, stock splits, stock dividends or other similar events that change the number or kind of shares outstanding, and extraordinary dividends or distributions of property to the Vistra stockholders.

Stock-Based Compensation Expense

Stock-based compensation expense is reported as SG&A in the consolidated statements of operations as follows:

	Year Ended December 31,		
	2023	2022	2021
Total stock-based compensation expense	$ 77	$ 65	$ 51
Income tax benefit	(18)	(15)	(12)
Stock based-compensation expense, net of tax	$ 59	$ 50	$ 39

Stock Options

The fair value of each stock option is estimated on the date of grant using a Black-Scholes option-pricing model. The risk-free interest rate used in the option valuation model was based on yields available on the grant dates for U.S. Treasury Strips with maturity consistent with the expected life assumption. The expected term of the option represents the period of time that options granted are expected to be outstanding and is based on the SEC Simplified Method (midpoint of average vesting time and contractual term). Expected volatility is based on an average of the historical, daily volatility of a peer group selected by Vistra over a period consistent with the expected life assumption ending on the grant date. We assumed a 2.3% dividend yield in the valuation of options granted in 2020. These options may be exercised over a three year graded vesting period and will expire 10 years from the grant date. No options were issued in 2021, 2022, or 2023.

Stock options outstanding at December 31, 2023 are all held by current or former employees. The following table summarizes our stock option activity:

	Year Ended December 31, 2023			
	Stock Options (in thousands)	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value (in millions)
Total outstanding at beginning of period	10,918	$ 20.10	5.1	$ 39.2
Exercised	(4,702)	$ 20.20		
Forfeited or expired	(90)	$ 21.68		
Total outstanding at end of period	6,126	$ 20.01	4.2	$ 113.5
Exercisable at December 31, 2023	6,126	$ 20.01	4.2	$ 113.5

As of December 31, 2023, there was no unrecognized compensation cost related to unvested stock options granted under the 2016 Incentive Plan.

Restricted Stock Units

The following table summarizes our restricted stock unit activity:

	Year Ended December 31, 2023	
	Restricted Stock Units (in thousands)	**Weighted Average Grant Date Fair Value**
Total nonvested at beginning of period	3,615	$ 21.49
Granted	2,119	$ 22.68
Vested	(1,610)	$ 22.08
Forfeited	(216)	$ 21.28
Total nonvested at end of period	3,908	$ 21.90

As of December 31, 2023, $50 million of unrecognized compensation cost related to unvested restricted stock units granted under the 2016 Incentive Plan are expected to be recognized over a weighted average period of approximately 2 years.

We also issue Performance Stock Units (PSUs) to certain members of management on an annual basis. All PSUs have a three year performance period and a payout opportunity of 0-200% of target (100%), which is intended to be settled in shares of Vistra common stock. We recognized compensation expense associated with PSUs of $36 million, $22 million and $9 million for the years ended December 31, 2023, 2022 and 2021, respectively. As of December 31, 2023, we have $33 million of unrecognized compensation cost associated with PSUs.

20. RELATED PARTY TRANSACTIONS

In connection with Emergence, we entered into agreements with certain of our affiliates and with parties who received shares of common stock and TRA Rights in exchange for their claims.

Registration Rights Agreement

Pursuant to the Plan of Reorganization, on the Effective Date, we entered into a Registration Rights Agreement (the RRA) with certain selling stockholders. Pursuant to the RRA, we maintain a registration statement on Form S-3 providing for registration of the resale of the Vistra common stock held by such selling stockholders. In addition, under the terms of the RRA, among other things, if we propose to file certain types of registration statements under the Securities Act with respect to an offering of equity securities, we will be required to use our reasonable best efforts to offer the other parties to the RRA the opportunity to register all or part of their shares on the terms and conditions set forth in the RRA.

Tax Receivable Agreement

On the Effective Date, Vistra entered into the TRA with a transfer agent on behalf of certain former first-lien creditors of TCEH. See Note 8 for discussion of the TRA.

21. SEGMENT INFORMATION

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.

Our Chief Executive Officer is our CODM. Our CODM reviews the results of these segments separately and allocates resources to the respective segments as part of our strategic operations. A measure of assets is not applicable, as segment assets are not regularly reviewed by the CODM for evaluating performance or allocating resources.

The Retail segment is engaged in retail sales of electricity and natural gas to residential, commercial and industrial customers. Substantially all of these activities are conducted by TXU Energy, Ambit, Dynegy Energy Services, Homefield Energy and U.S. Gas & Electric across 19 states in the U.S.

The Texas and East segments are engaged in electricity generation, wholesale energy sales and purchases, commodity risk management activities, fuel production and fuel logistics management. The Texas segment represents results from Vistra's electricity generation operations in the ERCOT market, other than assets that are now part of the Sunset or Asset Closure segments. The East segment represents results from 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, and includes operations in the PJM, ISO-NE and NYISO markets. We determined it was appropriate to aggregate results from these markets into one reportable segment, East, given similar economic characteristics.

The West segment represents results from the CAISO market, including our battery ESS projects at our Moss Landing power plant site (see Note 3).

The Sunset segment consists of generation plants with announced retirement dates after December 31, 2023. Separately reporting the Sunset segment differentiates operating plants with announced retirement plans from our other operating plants in the Texas, East and West segments. We have allocated unrealized gains and losses on the commodity risk management activities to the Sunset segment for the generation plants that have announced retirement dates after December 31, 2023.

The Asset Closure segment is engaged in the decommissioning and reclamation of retired plants and mines (see Note 4). The Asset Closure segment also includes results from generation plants we retired in the years ended December 31, 2023 and 2022. Upon movement of generation plant assets to either the Sunset or Asset Closure segments, prior year results are retrospectively adjusted, if the effects are material, for comparative purposes. Separately reporting the Asset Closure segment provides management with better information related to the performance and earnings power of Vistra's ongoing operations and facilitates management's focus on minimizing the cost associated with decommissioning and reclamation of retired plants and mines. We have allocated unrealized gains and losses on the commodity risk management activities attributable to the plants retired in 2022 and 2023.

Corporate and Other represents the remaining non-segment operations consisting primarily of general corporate expenses, interest, taxes and other expenses related to our support functions that provide shared services to our operating segments.

The accounting policies of the business segments are the same as those described in the summary of significant accounting policies in Note 1. Our CODM uses more than one measure to assess segment performance, but primarily focuses on Adjusted EBITDA. While we believe this is a useful metric in evaluating operating performance, it is not a metric defined by U.S. GAAP and may not be comparable to non-GAAP metrics presented by other companies. Adjusted EBITDA is most comparable to consolidated net income (loss) prepared based on U.S. GAAP. We account for intersegment sales and transfers as if the sales or transfers were to third parties, that is, at market prices. Certain shared services costs are allocated to the segments.

For the year ended	Retail	Texas	East	West	Sunset	A Cl
Operating revenues:						
December 31, 2023	$ 10,572	$ 3,823	$ 4,215	$ 914	$ 1,831	$
December 31, 2022	9,455	3,733	3,706	336	868	3
December 31, 2021	7,871	2,790	2,587	374	661	
Depreciation and amortization:						
December 31, 2023	$ (102)	$ (544)	$ (647)	$ (79)	$ (62)	$
December 31, 2022	(145)	(537)	(706)	(42)	(66)	(
December 31, 2021	(212)	(608)	(698)	(60)	(94)	(
Operating income (loss):						
December 31, 2023	$ 443	$ 300	$ 1,158	$ 425	$ 639	$ (1
December 31, 2022	1,172	(711)	(867)	(250)	(228)	(1
December 31, 2021	2,213	(2,601)	(552)	(8)	(67)	(4
Interest expense and related charges:						
December 31, 2023	$ (20)	$ 21	$ —	$ 8	$ (2)	$
December 31, 2022	(14)	20	(3)	6	(3)	
December 31, 2021	(9)	14	(15)	9	(3)	
Income tax (expense) benefit:						
December 31, 2023	$ —	$ —	$ (1)	$ —	$ —	$
December 31, 2022	—	—	—	—	—	
December 31, 2021	(2)	—	—	—	—	
Net income (loss):						
December 31, 2023	$ 424	$ 354	$ 1,160	$ 454	$ 633	$
December 31, 2022	1,158	(615)	(868)	(238)	(230)	(1

(a) Income tax (expense) benefit is generally not reflected in net income (loss) of the segments but is reflected almost entirely in Corporate and Other net income (loss).

22. SUPPLEMENTARY FINANCIAL INFORMATION

Impairment of Long-Lived Assets

In the first quarter of 2023, we recognized an impairment loss of $49 million related to our Kincaid generation facility in Illinois as a result of a significant decrease in the projected operating margins of the facility, primarily driven by a decrease in projected power prices. The impairment is reported in our Sunset segment and includes write-downs of property, plant and equipment of $45 million, write-downs of inventory of $2 million and write-downs of operating lease right-of-use assets of $2 million.

In the fourth quarter of 2022, we recognized an impairment loss of $74 million related to our Miami Fort generation facility in Ohio as a result of a significant decrease in the projected operating margins of the facility, reflecting an increase in projected coal costs along with a decrease in projected power prices. The impairment is reported in our Sunset segment and includes write-downs of property, plant and equipment of $71 million and write-downs of inventory of $3 million.

In the second quarter of 2021, we recognized an impairment loss of $38 million related to our Zimmer generation facility in Ohio as a result of a significant decrease in the estimated useful life of the facility, reflecting a decrease in the economic forecast of the facility and the inability to secure capacity revenues for the plant in the PJM capacity auction held in May 2021. The impairment is reported in our Asset Closure segment and includes write-downs of property, plant and equipment of $33 million and write-downs of inventory of $5 million.

In determining the fair value of the impaired asset groups in 2023, 2022, and 2021, we utilized the income approach described in ASC 820, *Fair Value Measurement* and, if applicable, applied weighting to prices and other relevant information generated by market transactions involving similar assets.

Interest Expense and Related Charges

	Year Ended December 31,		
	2023	2022	2021
Interest expense	$ 654	$ 591	$ 480
Unrealized mark-to-market net (gains) losses on interest rate swaps	36	(250)	(134)
Amortization of debt issuance costs, discounts and premiums	26	28	30
Facility Fee expense	8	—	—
Debt extinguishment (gain) loss	(3)	(1)	1
Capitalized interest	(37)	(29)	(26)
Other (a)	56	29	33
Total interest expense and related charges	$ 740	$ 368	$ 384

(a) For the year ended December 31, 2023, includes $21 million of fees related to the Commitment Letter (see Note 2).

The weighted average interest rate applicable to the Vistra Operations Credit Facilities, taking into account the interest rate swaps discussed in Note 12, was 5.69%, 4.30% and 3.90% as of December 31, 2023, 2022 and 2021, respectively.

Other Income and Deductions

	Year Ended December 31,		
	2023	2022	2021
Other income:			
Insurance settlements (a)	$ 24	$ 70	$ 88
Gain on sale of land (b)	95	8	9
Gain on TRA settlement (c)	29	—	—
Gain on settlement of rail transportation disputes (d)	—	—	15
Interest income	86	19	—
All other	23	20	28
Total other income	$ 257	$ 117	$ 140
Other deductions:			
All other	$ 14	$ 4	$ 16
Total other deductions	$ 14	$ 4	$ 16

(a) For the year ended December 31, 2023, $19 million reported in the West segment and $5 million in the Asset Closure segment. For the year ended December 31, 2022, $62 million reported in the Texas segment, $6 million reported in the West segment, $1 million reported in the Asset Closure segment and $1 million reported in the Corporate and Other non-segment. For the year ended December 31, 2021, $80 million reported in the Texas segment, $7 million reported in the Sunset segment and $1 million reported in Corporate and Other.
(b) For the year ended December 31, 2023, $94 million reported in the Asset Closure segment and $1 million reported in the Texas segment. For the years ended December 31, 2022 and 2021, reported in the Asset Closure segment.
(c) Reported in the Corporate and Other.
(d) Reported in the Asset Closure segment.

Restricted Cash

	December 31, 2023		December 31, 2022	
	Current Assets	Noncurrent Assets	Current Assets	Noncurrent Assets
Amounts related to remediation escrow accounts	$ 40	$ 14	$ 37	$ 33
Total restricted cash	$ 40	$ 14	$ 37	$ 33

Remediation Escrow — Vistra has transferred various asset retirement obligations related to several closed plant sites to a third-party remediation company. As part of certain transfers, Vistra deposits funds into escrow accounts, and the funds are released to the remediation company as milestones are reached in the remediation process. Amounts contractually payable to the third party in exchange for assuming the obligations are included in other current liabilities and other noncurrent liabilities and deferred credits.

Trade Accounts Receivable

	December 31,	
	2023	2022
Wholesale and retail trade accounts receivable	$ 1,735	$ 2,124
Allowance for uncollectible accounts	(61)	(65)
Trade accounts receivable — net	$ 1,674	$ 2,059

Gross trade accounts receivable as of December 31, 2023 and 2022 included unbilled retail revenues of $614 million and $607 million, respectively.

Allowance for Uncollectible Accounts Receivable

	Year Ended December 31,		
	2023	2022	2021
Allowance for uncollectible accounts receivable at beginning of period	$ 65	$ 45	$ 45
Increase for bad debt expense	164	179	110
Decrease for account write-offs	(168)	(159)	(110)
Allowance for uncollectible accounts receivable at end of period	$ 61	$ 65	$ 45

Inventories by Major Category

	December 31,	
	2023	2022
Materials and supplies	$ 289	$ 274
Fuel stock	420	252
Natural gas in storage	31	44
Total inventories	$ 740	$ 570

Investments

	December 31,	
	2023	2022
Nuclear decommissioning trust	$ 1,951	$ 1,648
Assets related to employee benefit plans	28	30
Land investments	42	41
Miscellaneous other	14	10
Total investments	$ 2,035	$ 1,729

Nuclear Decommissioning Trust

Investments in a trust that will be used to fund the costs to decommission the Comanche Peak nuclear generation plant are carried at fair value. Decommissioning costs are being recovered from Oncor customers as a delivery fee surcharge over the life of the plant and deposited by Vistra (and prior to the Effective Date, a subsidiary of TCEH) in the trust fund. Income and expense, including gains and losses associated with the trust fund assets and the decommissioning liability, are offset by a corresponding change in a regulatory asset/liability (currently a regulatory liability reported in other noncurrent liabilities and deferred credits) that will ultimately be settled through changes in Oncor's delivery fees rates. If funds recovered from Oncor's customers held in the trust fund are determined to be inadequate to decommission the Comanche Peak nuclear generation plant, Oncor would be required to collect all additional amounts from its customers, with no obligation from Vistra, provided that Vistra complied with PUCT rules and regulations regarding decommissioning trusts. A summary of the fair market value of investments in the fund follows:

	Year Ended December 31,	
	2023	2022
Debt securities (a)	$ 734	$ 658
Equity securities (b)	1,217	990
Total	$ 1,951	$ 1,648

(a) The investment objective for debt securities is to invest in a diversified tax efficient portfolio with an overall portfolio rating of AA or above as graded by S&P or Aa2 by Moody's. The debt securities are heavily weighted with government and municipal bonds and investment grade corporate bonds. The debt securities had an average coupon rate of 3.19% and 2.64% as of December 31, 2023 and 2022, respectively, and an average maturity of 11 years as of both December 31, 2023 and 2022.

(b) The investment objective for equity securities is to invest tax efficiently and to match the performance of the S&P 500 Index for U.S. equity investments and the MSCI EAFE Index for non-U.S. equity investments.

Debt securities held as of December 31, 2023 mature as follows: $296 million in one to five years, $142 million in five to 10 years and $296 million after 10 years.

The following table summarizes proceeds from sales of securities and investments in new securities.

	Year Ended December 31,		
	2023	2022	2021
Proceeds from sales of securities	$ 601	$ 670	$ 483
Investments in securities	$ (624)	$ (693)	$ (505)

Property, Plant and Equipment

	December 31,	
	2023	2022
Power generation and structures	$ 17,297	$ 16,597
Land	572	584
Office and other equipment	159	163
Total	18,028	17,344
Less accumulated depreciation	(6,657)	(5,753)
Net of accumulated depreciation	11,371	11,591
Finance lease right-of-use assets (net of accumulated depreciation)	160	173
Nuclear fuel (net of accumulated amortization of $120 million and $152 million)	379	268
Construction work in progress	522	522
Property, plant and equipment — net	$ 12,432	$ 12,554

Depreciation expenses totaled $1.344 billion, $1.388 billion and $1.478 billion for the years ended December 31, 2023, 2022 and 2021, respectively.

Our property, plant and equipment consist of our power generation assets, related mining assets, information system hardware, capitalized corporate office lease space and other leasehold improvements. The estimated remaining useful lives range from 1 to 30 years for our property, plant and equipment.

Asset Retirement and Mining Reclamation Obligations (ARO)

These liabilities primarily relate to nuclear generation plant decommissioning, land reclamation related to lignite mining, remediation or closure of coal ash basins, and generation plant disposal costs. There is no earnings impact with respect to changes in the nuclear plant decommissioning liability, as all costs are recoverable through the regulatory process as part of delivery fees charged by Oncor.

As of December 31, 2023, the carrying value of our ARO related to our nuclear generation plant decommissioning totaled $1.742 billion, which is lower than the fair value of the assets contained in the nuclear decommissioning trust. Since the costs to ultimately decommission that plant are recoverable through the regulatory rate making process as part of Oncor's delivery fees, a corresponding regulatory liability has been recorded to our consolidated balance sheet of $209 million in other noncurrent liabilities and deferred credits.

The following table summarizes the changes to these obligations, reported as AROs (current and noncurrent liabilities) in our consolidated balance sheets, for the years ended December 31, 2023, 2022 and 2021:

	Nuclear Plant Decommissioning	Land Reclamation, Coal Ash and Other	Total
Liability at December 31, 2020	$ 1,585	$ 851	$ 2,436
Additions:			
Accretion	50	38	88
Adjustment for change in estimates (a)	—	14	14
Reductions:			
Payments	—	(88)	(88)
Liability at December 31, 2021	1,635	815	2,450
Additions:			
Accretion	53	34	87
Adjustment for change in estimates (a)	—	49	49
Reductions:			
Payments	—	(88)	(88)
Liability transfers (b)	—	(61)	(61)
Liability at December 31, 2022	1,688	749	2,437
Additions:			
Accretion	54	34	88
Adjustment for change in estimates (a)	—	94	94
Reductions:			
Payments	—	(81)	(81)
Liability at December 31, 2023	1,742	796	2,538
Less amounts due currently	—	(124)	(124)
Noncurrent liability at December 31, 2023	$ 1,742	$ 672	$ 2,414

(a) Includes non-cash additions to asset retirement costs included in property, plant and equipment of $67 million, $19 million and $19 million for the years ended December 31, 2023, 2022 and 2021, respectively.
(b) Represents ARO transferred to a third-party for remediation. Any remaining unpaid third-party obligation has been reclassified to other current liabilities and other noncurrent liabilities and deferred credits in our consolidated balance sheets.

Other Noncurrent Liabilities and Deferred Credits

The balance of other noncurrent liabilities and deferred credits consists of the following:

	December 31,	
	2023	2022
Retirement and other employee benefits (Note 18)	$ 247	$ 237
Winter Storm Uri impact (a)	26	35
Identifiable intangible liabilities (Note 6)	131	140
Regulatory liability (b)	209	—
Finance lease liabilities	227	237
Uncertain tax positions, including accrued interest	—	13
Liability for third-party remediation	17	37
Accrued severance costs	36	36
Other accrued expenses	58	269
Total other noncurrent liabilities and deferred credits	$ 951	$ 1,004

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(a) Includes future bill credits related to large commercial and industrial customers that curtailed during Winter Storm Uri.

(b) As of December 31, 2023, the fair value of the assets contained in the nuclear decommissioning trust was higher than the carrying value of our ARO related to our nuclear generation plant decommissioning and recorded as a regulatory liability of $209 million in other noncurrent liabilities and deferred credits. As of December 31, 2022, the carrying value of our ARO related to our nuclear generation plant decommissioning was higher than fair value of the assets contained in the nuclear decommissioning trust and recorded as a regulatory asset of $40 million in other noncurrent assets.

Fair Value of Debt

		December 31, 2023		December 31, 2022	
Long-term debt (see Note 12):	**Fair Value Hierarchy**	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt under the Vistra Operations Credit Facilities	Level 2	$ 2,456	$ 2,500	$ 2,519	$ 2,486
Vistra Operations Senior Notes	Level 2	11,881	11,752	9,378	8,830
Equipment Financing Agreements	Level 3	65	62	74	72

We determine fair value in accordance with accounting standards as discussed in Note 16. We obtain security pricing from an independent party who uses broker quotes and third-party pricing services to determine fair values. Where relevant, these prices are validated through subscription services, such as Bloomberg.

Supplemental Cash Flow Information

The following table reconciles cash, cash equivalents and restricted cash reported in our consolidated statements of cash flows to the amounts reported in our consolidated balance sheets at December 31, 2023 and 2022:

	December 31,	
	2023	**2022**
Cash and cash equivalents	$ 3,485	$ 455
Restricted cash included in current assets	40	37
Restricted cash included in noncurrent assets	14	33
Total cash, cash equivalents and restricted cash	$ 3,539	$ 525

The following table summarizes our supplemental cash flow information for the years ended December 31, 2023, 2022 and 2021, respectively.

	Year Ended December 31,		
	2023	2022	2021
Cash payments related to:			
Interest paid	$ 636	$ 581	$ 482
Capitalized interest	(37)	(29)	(26)
Interest paid (net of capitalized interest)	$ 599	$ 552	$ 456
Non-cash investing and financing activities:			
Accrued property, plant and equipment additions (a)	$ 104	$ 103	$ 171
Book value of nuclear fuel sold	$ 26	$ —	$ —

(a) Represents property, plant and equipment accruals during the period for which cash has not been paid as of the end of the period.

For the years ended December 31, 2023, 2022 and 2021, we paid federal income taxes of zero, $1 million and zero, respectively, paid state income taxes of $44 million, $33 million and $52 million, respectively, and received state tax refunds of $13 million, $8 million and $2 million, respectively.

Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

Item 9A. CONTROLS AND PROCEDURES

An evaluation was performed under the supervision and with the participation of our management, including the principal executive officer and principal financial officer, of the effectiveness of the design and operation of the disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15a-15(e) of the Exchange Act) in effect at December 31, 2023. Based on the evaluation performed, our principal executive officer and principal financial officer concluded that the disclosure controls and procedures were effective as of that date.

There have been no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(e) and 15a-15(e) of the Exchange Act) during the most recently completed fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

VISTRA CORP.
MANAGEMENT'S ANNUAL REPORT ON
INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Vistra Corp. is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934) for the company. Vistra Corp.'s internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in condition or the deterioration of compliance with procedures or policies.

The management of Vistra Corp. performed an evaluation of the effectiveness of the company's internal control over financial reporting as of December 31, 2023 based on the Committee of Sponsoring Organizations of the Treadway Commission's (COSO's) *Internal Control - Integrated Framework (2013)*. Based on the review performed, management believes that as of December 31, 2023 Vistra Corp.'s internal control over financial reporting was effective.

The independent registered public accounting firm of Deloitte & Touche LLP as auditors of the consolidated financial statements of Vistra Corp. has issued an attestation report on Vistra Corp.'s internal control over financial reporting.

/s/ JAMES A. BURKE		/s/ KRISTOPHER E. MOLDOVAN
James A. Burke		Kristopher E. Moldovan
President and Chief Executive Officer		Chief Financial Officer
(Principal Executive Officer)		(Principal Financial Officer)

February 28, 2024

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of Vistra Corp.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Vistra Corp. and subsidiaries (the “Company”) as of December 31, 2023, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2023, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2023, of the Company and our report dated February 28, 2024, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company’s internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte & Touche LLP

Dallas, Texas
February 28, 2024

Item 9B. OTHER INFORMATION

(a) On February 25, 2024, Brian Ferraioli notified the Company that he will not seek re-election and will resign as a member of the Board of Directors (Board) of the Company, effective as of the date of the Company's 2024 annual meeting of stockholders (Annual Meeting). Mr. Ferraioli's other business and professional opportunities have increased in demand, and he is resigning from the Board to focus on those other opportunities. Mr. Ferraioli has served as a director of the Company since 2017. Mr. Ferraioli's decision not to seek re-election is not the result of any disagreement with the Company on any matter relating to the Company's operations, policies or practices.

In addition, on February 26, 2024, Jeff Hunter notified the Company that he will not seek re-election and will resign as a member of the Board, effective as of the Annual Meeting. Mr. Hunter's other business and professional opportunities have increased in demand, and he is resigning from the Board to focus on those other opportunities. Mr. Hunter has served as a director of the Company since 2016. Mr. Hunter's decision not to seek re-election is not the result of any disagreement with the Company on any matter relating to the Company's operations, policies or practices.

The Board and the Company express sincere appreciation to Messrs. Ferraioli and Hunter for their leadership, strategic contributions, and dedicated service to the Board and the Company.

(b) During the three months ended December 31, 2023, none of our officers or directors adopted or terminated any contract, instruction, or written plan for the purchase or sale of Company securities that was intended to satisfy the affirmative defense conditions of Rule 10b5-1(c) or any "non-Rule 10b5-1 trading arrangement".

Item 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

None.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Code of Ethics

Vistra has adopted a code of ethics entitled "Vistra Code of Conduct" that applies to directors, officers and employees, including the chief executive officer and senior financial officers of Vistra. It may be accessed through the "Corporate Governance" section of the Company's website at *www.vistracorp.com*. Vistra also elects to disclose the information required by Form 8-K, Item 5.05, "Amendments to the Registrant's Code of Ethics, or Waiver of a Provision of the Code of Ethics," through the Company's website and will disclose such events within four business days following the date of the amendment or waiver, and such information will remain available on this website for at least a 12-month period. A copy of the "Vistra Code of Conduct" is available in print to any stockholder who requests it.

Other information required by this Item is incorporated by reference to the similarly named section of Vistra Definitive Proxy Statement for its 2024 Annual Meeting of Stockholders.

Item 11. EXECUTIVE COMPENSATION

Information required by this Item is incorporated by reference to the similarly named section of Vistra's Definitive Proxy Statement for its 2024 Annual Meeting of Stockholders.

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by this Item is incorporated by reference to the sections entitled "Beneficial Ownership of Common Stock of the Company" in Vistra's Definitive Proxy Statement for its 2024 Annual Meeting of Stockholders.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required by this Item is incorporated by reference to the sections entitled "Business Relationships and Related Person Transactions Policy" and "Director Independence" in Vistra's Definitive Proxy Statement for its 2024 Annual Meeting of Stockholders.

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required by this Item is incorporated by reference to the sections entitled "Principal Accounting Fees" in Vistra's Definitive Proxy Statement for its 2024 Annual Meeting of Stockholders.

Deloitte & Touche LLP's PCAOB ID Number is 34.

PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Our financial statements and financial statement schedules are incorporated under Part II, Item 8 of this annual report on Form 10-K.

(b) **SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT**

VISTRA CORP. (PARENT)
SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED STATEMENTS OF OPERATIONS
(Millions of Dollars)

	Year Ended December 31,		
	2023	2022	2021
Depreciation and amortization	$ (15)	$ (16)	$ (17)
Selling, general and administrative expenses	(80)	(69)	(53)
Operating loss	(95)	(85)	(70)
Other income	31	6	3
Impacts of Tax Receivable Agreement	(164)	(128)	53
Loss before income tax benefit	(228)	(207)	(14)
Income tax benefit	58	47	4
Equity in earnings (losses) of subsidiaries, net of tax	1,663	(1,067)	(1,264)
Net income (loss)	$ 1,493	$ (1,227)	$ (1,274)

See Notes to the Condensed Financial Statements.

VISTRA CORP. (PARENT)
SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED STATEMENTS OF CASH FLOWS

(Millions of Dollars)

	Year Ended December 31,		
	2023	2022	2021
Cash flows — operating activities:			
Cash used in operating activities	$ (31)	$ (27)	$ (38)
Cash flows — investing activities:			
Capital expenditures	—	—	—
Dividend received from subsidiaries	1,625	1,775	405
Equity contribution to subsidiaries	—	—	(988)
Cash provided by (used in) investing activities	1,625	1,775	(583)
Cash flows — financing activities:			
Issuances of preferred stock	—	—	2,000
Stock repurchases	(1,245)	(1,949)	(471)
Dividends paid to common stockholders	(313)	(302)	(290)
Dividends paid to preferred stockholders	(150)	(151)	—
Other, net	91	40	(23)
Cash provided by (used in) financing activities	(1,617)	(2,362)	1,216
Net change in cash, cash equivalents and restricted cash	(23)	(614)	595
Cash, cash equivalents and restricted cash — beginning balance	54	668	73
Cash, cash equivalents and restricted cash — ending balance	$ 31	$ 54	$ 668

See Notes to the Condensed Financial Statements.

VISTRA CORP. (PARENT)
SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT
CONDENSED BALANCE SHEETS
(Millions of Dollars)

	December 31, 2023	December 31, 2022
ASSETS		
Cash and cash equivalents	$ 31	$ 54
Trade accounts receivable — net	—	11
Income taxes receivable	6	27
Prepaid expense and other current assets	—	1
Total current assets	37	93
Investment in affiliated companies	4,507	4,462
Property, plant and equipment — net	3	3
Identifiable intangible assets — net	—	15
Accumulated deferred income taxes	1,086	1,019
Total assets	$ 5,633	$ 5,592
LIABILITIES AND EQUITY		
Trade accounts payable	$ 12	$ 3
Accounts payable —affiliates	91	122
Accrued taxes	12	(1)
Other current liabilities	12	9
Total current liabilities	127	133
Tax Receivable Agreement obligations	164	514
Other noncurrent liabilities and deferred debits	20	27
Total liabilities	311	674
Total stockholders' equity	5,322	4,918
Total liabilities and equity	$ 5,633	$ 5,592

See Notes to the Condensed Financial Statements.

NOTES TO CONDENSED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION

The accompanying unconsolidated condensed balance sheets, statements of net loss and cash flows present results of operations and cash flows of Vistra Corp. (Parent). Certain information and footnote disclosures normally included in financial statements prepared in accordance with U.S. GAAP have been omitted pursuant to the rules of the SEC. Because the unconsolidated condensed financial statements do not include all of the information and footnotes required by U.S. GAAP, they should be read in conjunction with the financial statements and related notes of Vistra Corp. and Subsidiaries included in the annual report on Form 10-K for the year ended December 31, 2023. Vistra Corp.'s subsidiaries have been accounted for under the equity method. All dollar amounts in the financial statements and tables in the notes are stated in millions of U.S. dollars unless otherwise indicated.

Vistra Corp. (Parent) files a consolidated U.S. federal income tax return. Consolidated tax expenses or benefits and deferred tax assets or liabilities have been allocated to the respective subsidiaries in accordance with the accounting rules that apply to separate financial statements of subsidiaries.

2. RESTRICTIONS ON SUBSIDIARIES

The Vistra Operations Credit Agreement generally restricts the ability of Vistra Operations to make distributions to any direct or indirect parent unless such distributions are expressly permitted thereunder. As of December 31, 2023, Vistra Operations can distribute approximately $6.3 billion to Vistra Corp. (Parent) under the Vistra Operations Credit Agreement without the consent of any party. The amount that can be distributed by Vistra Operations to Parent was partially reduced by distributions made by Vistra Operations to Vistra Corp. (Parent) of approximately $1.625 billion, $1.775 billion and $405 million during the years ended December 31, 2023, 2022 and 2021, respectively. Additionally, Vistra Operations may make distributions to Vistra Corp. (Parent) in amounts sufficient for Vistra Corp. (Parent) to make any payments required under the TRA or the Tax Matters Agreement or, to the extent arising out of Vistra Corp. (Parent)'s ownership or operation of Vistra Operations, to pay any taxes or general operating or corporate overhead expenses. As of December 31, 2023, all of the restricted net assets of Vistra Operations may be distributed to Vistra Corp. (Parent).

3. GUARANTEES

Vistra Corp. (Parent) has entered into contracts that contain guarantees to unaffiliated parties that could require performance or payment under certain conditions. As of December 31, 2023, there are no material outstanding claims related to guarantee obligations of Vistra Corp. (Parent), and Vistra Corp. (Parent) does not anticipate it will be required to make any material payments under these guarantees in the near term.

4. DIVIDEND RESTRICTIONS

Under applicable law, Vistra Corp. (Parent) is prohibited from paying any dividend to the extent that immediately following payment of such dividend there would be no statutory surplus or Vistra Corp. (Parent) would be insolvent.

Vistra Corp. (Parent) received $1.625 billion, $1.775 billion and $405 million in dividends from its consolidated subsidiaries in the years ended December 31, 2023, 2022 and 2021, respectively. In the year ended December 31, 2021, Vistra Corp. (Parent) made an equity contribution to Vistra Operations of $988 million.

(c) EXHIBITS:

Exhibits	Previously Filed With File Number*	As Exhibit		
(2)	**Plan of Acquisition, Reorganization, Arrangement, Liquidation, or Succession**			
2.1	333-215288 Form S-1 (filed December 23, 2016)	2.1	—	Order of the United States Bankruptcy Court for the District of Delaware Confirming the Third Amended Joint Plan of Reorganization
2.2	001-38086 Form 8-K (filed October 31, 2017)	2.1	—	Agreement and Plan of Merger, dated as of October 29, 2017, by and between Vistra Energy Corp. (now known as Vistra Corp.) and Dynegy, Inc.
2.3	001-38086 Form 8-K (filed March 7, 2023)	2.1	—	Transaction Agreement, dated March 6, 2023, by and among Vistra Operations Company LLC, Black Pen Inc. and Energy Harbor Corp.
(3(i))	**Articles of Incorporation**			
3.1	001-38086 Form 8-K (filed May 4, 2020)	3.1	—	Restated Certificate of Incorporation of Vistra Energy Corp. (now known as Vistra Corp.)
3.2	001-38086 Form 8-K (filed June 29, 2020)	3.1	—	Certificate of Amendment of the Restated Certificate of Incorporation of Vistra Energy Corp. (now known as Vistra Corp.), effective July 2, 2020
3.3	001-38086 Form 8-K (filed on October 15, 2021)	3.1	—	Series A Preferred Stock Certificate of Designation, filed with the Secretary of State of Delaware on October 14, 2021

Exhibits	Previously Filed With File Number*	As Exhibit		
3.4	001-38086 Form 8-K (filed on December 13, 2021)	3.1	—	Series B Preferred Stock Certificate of Designation, filed with the Secretary of State of Delaware on December 9, 2021
3.5	001-38086 Form 8-K (filed on January 4, 2024)	3.1	—	Series C Preferred Stock Certificate of Designation filed with the Secretary of State of Delaware on December 29, 2023
(3(ii))	**By-laws**			
3.5	001-38086 Form 10-K (Year ended December 31, 2021) (filed on February 25, 2022)	3.5	—	Amended and Restated Bylaws of Vistra Corp., effective February 23, 2022
(4)	**Instruments Defining the Rights of Security Holders, Including Indentures**			
4.1	001-38086 Form 8-K (filed on August 23, 2018)	4.1	—	Indenture for 5.500% Senior Note due 2026, dated as of August 22, 2018, among Vistra Operations Company LLC, as issuer, the Subsidiary Guarantors (as defined therein), and Wilmington Trust, National Association, as Trustee
4.2	001-38086 Form 8-K (filed on August 23, 2018)	4.2	—	Form of Rule 144A Global Security for 5.500% Senior Note due 2026 (included in Exhibit 4.1)
4.3	001-38086 Form 8-K (filed on August 23, 2018)	4.3	—	Form of Regulation S Global Security for 5.500% Senior Note due 2026 (included in Exhibit 4.1)
4.4	001-38086 Form 10-Q (Quarter ended September 30, 2019) (filed on November 5, 2019)	4.5	—	First Supplemental Indenture for the 5.500% Senior Notes due 2026, dated August 30, 2019, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.5	001-38086 Form 10-K (Year ended December 31, 2019) (filed on February 28, 2020)	4.36	—	Second Supplemental Indenture for the 5.500% Senior Notes due 2026, dated October 25, 2019, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.6	001-38086 Form 10-Q (Quarter ended March 31, 2020) (filed on May 5, 2020)	4.5	—	Third Supplemental Indenture for the 5.500% Senior Notes due 2026, dated January 31, 2020, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.7	001-38086 Form 10-Q (Quarter ended March 31, 2020)	4.6	—	Fourth Supplemental Indenture for the 5.500% Senior Notes due 2026, dated March 26, 2020, among the Guaranteeing Subsidiaries, the

Exhibits	Previously Filed With File Number*	As Exhibit		
4.12	001-38086 Form 10-K (Year ended December 31, 2022) (filed on March 1, 2023)	4.12	—	Ninth Supplemental Indenture for the 5.500% Senior Notes due 2026, dated December 15, 2022, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.13	001-38086 Form 10-Q (Quarter ended September 30, 2023) (filed on November 7, 2023)	4.1	—	Tenth Supplemental Indenture for the 5.500% Senior Notes due 2026, dated July 31, 2023, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.14	001-38086 Form 8-K (filed on February 6, 2019)	4.1	—	Indenture for 5.625% Senior Note due 2027, dated as of February 6, 2019, among Vistra Operations Company LLC, as issuer, the Subsidiary Guarantors (as defined therein), and Wilmington Trust, National Association, as Trustee
4.15	001-38086 Form 8-K (filed on February 6, 2019)	4.2	—	Form of Rule 144A Global Security for 5.625% Senior Note due 2027 (included in Exhibit 4.1)
4.16	001-38086 Form 8-K (filed on February 6, 2019)	4.3	—	Form of Regulation S Global Security for 5.625% Senior Note due 2027 (included in Exhibit 4.1)
4.17	001-38086 Form 10-Q (Quarter ended September 30, 2019) (filed on November 5, 2019)	4.6	—	First Supplemental Indenture for the 5.625% Senior Notes due 2027, dated August 30, 2019, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.18	001-38086 Form 10-K (Year ended December 31, 2019) (filed on February 28, 2020)	4.41	—	Second Supplemental Indenture for the 5.625% Senior Notes due 2027, dated October 25, 2019, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.19	001-38086 Form 10-Q (Quarter ended March 31, 2020) (filed on May 5, 2020)	4.7	—	Third Supplemental Indenture for the 5.625% Senior Notes due 2027, dated January 31, 2020, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.20	001-38086 Form 10-Q (Quarter ended March 31, 2020) (filed on May 5, 2020)	4.8	—	Fourth Supplemental Indenture for the 5.625% Senior Notes due 2027, dated March 26, 2020, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.21	001-38086 Form 10-K (Year ended December	4.17	—	Fifth Supplemental Indenture for the 5.625% Senior Notes due 2027, dated October 7, 2020, among the

Exhibits	Previously Filed With File Number*	As Exhibit		
4.26	001-38086 Form 10-Q (Quarter ended September 30, 2023) (filed on November 7, 2023)	4.2	—	Tenth Supplemental Indenture for the 5.625% Senior Notes due 2027, dated July 31, 2023, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.27	001-38086 Form 8-K (filed on June 24, 2019)	4.1	—	Indenture for 5.00% Senior Notes due 2027, dated as of June 21, 2019, among Vistra Operations Company LLC, as Issuer, the Subsidiary Guarantors (as defined therein), and Wilmington Trust, National Association, as Trustee
4.28	001-38086 Form 8-K (filed on June 24, 2019)	4.2	—	Form of Rule 144A Global Security for 5.00% Senior Notes due 2027 (included in Exhibit 4.1)
4.29	001-38086 Form 8-K (filed on June 24, 2019)	4.3	—	Form of Regulation S Global Security for 5.00% Senior Notes due 2027 (included in Exhibit 4.1)
4.30	001-38086 Form 10-Q (Quarter ended September 30, 2019) (filed on November 5, 2019)	4.7	—	First Supplemental Indenture for the 5.000% Senior Notes due 2027, dated August 30, 2019, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.31	001-38086 Form 10-K (Year ended December 31, 2019) (filed on February 28, 2020)	4.46	—	Second Supplemental Indenture for the 5.000% Senior Notes due 2027, dated October 25, 2019, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.32	001-38086 Form 10-Q (Quarter ended March 31, 2020) (filed on May 5, 2020)	4.9	—	Third Supplemental Indenture for the 5.000% Senior Notes due 2027, dated January 31, 2020, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.33	001-38086 Form 10-Q (Quarter ended March 31, 2020) (filed on May 5, 2020)	4.10	—	Fourth Supplemental Indenture for the 5.000% Senior Notes due 2027, dated March 26, 2020, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.34	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	4.26	—	Fifth Supplemental Indenture for the 5.000% Senior Notes due 2027, dated October 7, 2020, among the Guaranteeing Subsidiaries, the Company, the Subsidiary Guarantors and the Trustee
4.35	001-38086 Form 10-K (Year ended December	4.27	—	Sixth Supplemental Indenture for the 5.000% Senior Notes due 2027, dated January 8, 2021, among the

Exhibits	Previously Filed With File Number*	As Exhibit		
4.40	001-38086 Form 8-K (filed on June 17, 2019)	4.1	—	Indenture, dated as of June 11, 2019, between Vistra Operations Company LLC, as Issuer, and Wilmington Trust, National Association, as Trustee
4.41	001-38086 Form 8-K (filed on June 17, 2019)	4.2	—	Supplemental Indenture for 3.55% Senior Secured Notes due 2024 and 4.30% Senior Secured Notes Due 2029, dated as of June 11, 2019, among Vistra Operations Company LLC, as Issuer, the Subsidiary Guarantors (as defined therein), and Wilmington Trust, National Association, as Trustee
4.42	001-38086 Form 8-K (filed on June 17, 2019)	4.3	—	Form of Rule 144A Global Security for 3.55% Senior Notes due 2024 (included in Exhibit 4.2)
4.43	001-38086 Form 8-K (filed on June 17, 2019)	4.4	—	Form of Rule 144A Global Security for 4.30% Senior Notes due 2029 (included in Exhibit 4.2)
4.44	001-38086 Form 8-K (filed on June 17, 2019)	4.5	—	Form of Regulation S Global Security for 3.55% Senior Notes due 2024 (included in Exhibit 4.2)
4.45	001-38086 Form 8-K (filed on June 17, 2019)	4.6	—	Form of Regulation S Global Security for 4.30% Senior Notes due 2029 (included in Exhibit 4.2)
4.46	001-38086 Form 10-Q (Quarter ended September 30, 2019) (filed on November 5, 2019)	4.8	—	Second Supplemental Indenture for 3.55% Senior Secured Notes due 2024 and 4.30% Senior Secured Notes due 2029, dated as of August 30, 2019, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.47	001-38086 Form 8-K (filed on November 21, 2019)	4.1	—	Third Supplemental Indenture for 3.55% Senior Secured Notes due 2024 and 4.30% Senior Secured Notes due 2029, dated as of October 25, 2019, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, Subsidiary Guarantors and the Trustee
4.48	001-38086 Form 8-K (filed on November 21, 2019)	4.2	—	Fourth Supplemental Indenture, dated as of November 15, 2019, among Vistra Operations Company LLC, as Issuer, the Subsidiary Guarantors (as defined therein), and Wilmington Trust, National Association, as

Exhibits	Previously Filed With File Number*	As Exhibit		
4.54	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	4.42	—	Eighth Supplemental Indenture for 3.55% Senior Secured Notes due 2024, 3.70% Senior Secured Notes due 2027 and 4.30% Senior Secured Notes due 2029, dated as of January 8, 2021, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.55	001-38086 Form 10-Q (Quarter ended September 30, 2021) (filed on November 5, 2021)	4.6	—	Ninth Supplemental Indenture for 3.55% Senior Secured Notes due 2024, 3.70% Senior Secured Notes due 2027 and 4.30% Senior Secured Notes due 2029, dated as of July 29, 2021, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.56	001-38086 Form 10-K (Year ended December 31, 2021) (filed on February 25, 2022)	4.50	—	Tenth Supplemental Indenture for 3.55% Senior Secured Notes due 2024, 3.70% Senior Secured Notes due 2027 and 4.30% Senior Secured Notes due 2029, dated as of December 28, 2021, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.57	001-38086 Form 8-K (filed on May 16, 2022)	4.1	—	Eleventh Supplemental Indenture for 4.875% Senior Secured Notes due 2024 and 5.125% Senior Secured Notes due 2025, dated as of May 13, 2022, among Vistra Operations Company LLC, as Issuer, the Subsidiary Guarantors and the Trustee
4.58	001-38086 Form 8-K (filed on May 16, 2022)	4.2	—	Form of Rule 144A Global Security for 4.875% Senior Note due 2024 (included in Exhibit 4.1)
4.59	001-38086 Form 8-K (filed on May 16, 2022)	4.3	—	Form of Regulation S Global Security for 4.875% Senior Note due 2024 (included in Exhibit 4.1)
4.60	001-38086 Form 8-K (filed on May 16, 2022)	4.4	—	Form of Rule 144A Global Security for 5.125% Senior Note due 2025 (included in Exhibit 4.1)
4.61	001-38086 Form 8-K (filed on May 16, 2022)	4.5	—	Form of Regulation S Global Security for 5.125% Senior Note due 2025 (included in Exhibit 4.1)
4.62	001-38086	4.55		Twelfth Supplemental Indenture for

Exhibits	Previously Filed With File Number*	As Exhibit		
4.67	001-38086 Form 8-K (filed on October 2, 2023)	4.4	—	Form of Regulation S Global Security for 6.950% Senior Secured Note due 2033 (included in Exhibit 4.1)
4.68	001-38086 Form 8-K (filed on October 2, 2023)	4.5	—	Form of Rule 144A Global Security for 7.750% Senior Unsecured Note due 2031 (included in Exhibit 4.2)
4.69	001-38086 Form 8-K (filed on October 2, 2023)	4.6	—	Form of Regulation S Global Security for 7.750% Senior Unsecured Note due 2031 (included in Exhibit 4.2)
4.70	001-38086 Form 8-K (filed on May 11, 2021)	4.1	—	Indenture for 4.375% Senior Notes due 2029, dated as of May 10, 2021, between Vistra Operations Company LLC, as Issuer, the Subsidiary Guarantors, and Wilmington Trust, National Association, as Trustee
4.71	001-38086 Form 8-K (filed on May 11, 2021)	4.2	—	Form of Rule 144A Global Security for 4.375% Senior Notes due 2029 (included in Exhibit 4.1)
4.72	001-38086 Form 8-K (filed on May 11, 2021)	4.3	—	Form of Regulation S Global Security for 4.375% Senior Notes due 2029 (included in Exhibit 4.1)
4.73	001-38086 Form 10-Q (Quarter ended September 30, 2021) (filed on November 5, 2021)	4.7	—	First Supplemental Indenture for the 4.375% Senior Notes due 2029, dated July 29, 2021, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.74	001-38086 Form 10-K (Year ended December 31, 2021) (filed on February 25, 2022)	4.55	—	Second Supplemental Indenture for the 4.375% Senior Notes due 2029, dated December 28, 2021, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.75	001-38086 Form 10-K (Year ended December 31, 2022) (filed on March 1, 2023)	4.65	—	Third Supplemental Indenture for the 4.375% Senior Notes due 2029, dated December 15, 2022, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee
4.76	001-38086 Form 10-Q (Quarter ended September 30, 2023) (filed on November 7, 2023)	4.5	—	Fourth Supplemental Indenture for the 4.375% Senior Notes due 2029, dated July 31, 2023, among Vistra Operations Company LLC, as Issuer, the Guaranteeing Subsidiaries, the Subsidiary Guarantors and the Trustee

Exhibits	Previously Filed With File Number*	As Exhibit		
4.81	001-38086 Form 8-K (filed on July 19, 2019)	4.1	—	Third Amendment to Purchase and Sale Agreement, dated as of July 15, 2019, among TXU Energy Retail Company LLC, Dynegy Energy Services, LLC, and Dynegy Energy Services (East), LLC, each as an originator, and TXU Energy Receivables Company LLC, as purchaser
4.82	001-38086 Form 8-K (filed on October 16, 2020)	4.1	—	Fourth Amendment to Purchase and Sale Agreement, dated as of October 9, 2020, among TXU Energy Retail Company LLC, as an originator and servicer, the other originators named therein, and TXU Energy Receivables Company LLC, as purchaser
4.83	001-38086 Form 8-K (filed on December 28, 2020)	4.1	—	Fifth Amendment to Purchase and Sale Agreement, dated as of December 21, 2020, among TXU Energy Retail Company LLC, certain originators named therein, and TXU Energy Receivables Company LLC, as purchaser
4.84	001-38086 Form 8-K (filed on April 5, 2019)	4.2	—	First Amendment to Receivables Purchase Agreement, dated as of April 1, 2019, among TXU Energy Receivables Company LLC, as seller, TXU Energy Retail Company LLC, as servicer, Vistra Operations Company LLC, as performance guarantor, certain purchaser agents and purchasers named therein and Credit Agricole Corporate and Investment Bank, as administrator
4.85	001-38086 Form 10-Q (Quarter ended June 30, 2019) (filed on August 2, 2019)	4.13	—	Second Amendment to Receivables Purchase Agreement, dated as of June 3, 2019, among TXU Energy Receivables Company LLC, as seller, TXU Energy Retail Company LLC, as servicer, Vistra Operations Company LLC, as performance guarantor, certain purchaser agents and purchasers named therein and Credit Agricole Corporate and Investment Bank, as administrator
4.86	001-38086 Form 8-K (filed on July 19, 2019)	4.2	—	Third Amendment to Receivables Purchase Agreement, dated as of July 15, 2019, among TXU Energy Receivables Company LLC, as seller, TXU Energy Retail Company LLC, as servicer, Vistra Operations Company LLC, as performance guarantor, certain purchaser agents and purchasers named therein and Credit Agricole Corporate and

Exhibits		Previously Filed With File Number*	As Exhibit		
4.91		001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	4.56	—	Eighth Amendment to Receivables Purchase Agreement, dated as of February 19, 2020, among TXU Energy Receivables Company LLC, as seller, TXU Energy Retail Company LLC, as servicer, Vistra Operations Company LLC, as performance guarantor, certain purchaser agents and purchasers named therein, and Credit Agricole Corporate and Investment Bank, as administrator
4.92		001-38086 Form 10-Q (Quarter ended March 31, 2021) (filed on May 4, 2021)	4.6	—	Ninth Amendment to Receivables Purchase Agreement, dated as of March 26, 2021, among TXU Energy Receivables Company LLC, as seller, TXU Energy Retail Company LLC, as servicer, Vistra Operations Company LLC, as performance guarantor, certain purchaser agents and purchasers named therein, and Credit Agricole Corporate and Investment Bank, as administrator
4.93		001-38086 Form 8-K (filed on July 15, 2021)	4.1	—	Tenth Amendment to Receivables Purchase Agreement, dated as of July 9, 2021, among TXU Energy Receivables Company LLC, as seller, TXU Energy Retail Company LLC, as servicer, Vistra Operations Company LLC, as performance guarantor, certain purchaser agents and purchasers named therein, and Credit Agricole Corporate and Investment Bank, as administrator
4.94		001-38086 Form 10-Q (Quarter ended September 30, 2021) (filed on November 5, 2021)	4.2	—	Eleventh Amendment to Receivables Purchase Agreement, dated as of July 16, 2021, among TXU Energy Receivables Company LLC, as seller, TXU Energy Retail Company LLC, as servicer, Vistra Operations Company LLC, as performance guarantor, certain purchaser agents and purchasers named therein, and Credit Agricole Corporate and Investment Bank, as administrator
4.95		001-38086 Form of 8-K (filed on July 15, 2022)	4.1	—	Twelfth Amendment to Receivables Purchase Agreement, dated as of July 11, 2022, among TXU Energy Receivables Company LLC, as seller, TXU Energy Retail Company LLC, as servicer, Vistra Operations Company LLC, as performance guarantor, certain purchaser agents and purchasers named therein, and Credit Agricole Corporate and Investment Bank, as administrator

Exhibits	Previously Filed With File Number*	As Exhibit		
4.102	001-38086 Form 10-Q (Quarter ended September 30, 2023) (filed on November 7, 2023)	4.6	—	Second Supplemental Indenture for the 7.233% Senior Secured Notes due 2028, dated August 3, 2023, among Vistra Operations Company LLC, as Issuer, the subsidiary guarantors party thereto and the Bank of New York Mellon Trust Company, N.A., as trustee
4.103	333-215288 Form S-1 (filed December 23, 2016)	4.1	—	Registration Rights Agreement, by and among TCEH Corp. (now known as Vistra Corp.) and the Holders party thereto, dated as of October 3, 2016
4.104	**		—	Description of Capital Stock
(10)	**Material Contracts**			
	Management Contracts; Compensatory Plans, Contracts and Arrangements			
10.1	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.6	—	2016 Omnibus Incentive Plan
10.2	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.7	—	Form of Option Award Agreement (Management) for 2016 Omnibus Incentive Plan (pre-2021 awards)
10.3	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.8	—	Form of Restricted Stock Unit Award Agreement (Management) for 2016 Omnibus Incentive Plan (pre-2021 awards)
10.4	001-33443 Form10-K (Year ended December 31, 2017) (filed on February 26, 2018)	10(d)	—	Form of Performance Stock Unit Award Agreement for 2016 Omnibus Incentive Plan (pre-2021 awards)
10.5	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	10.5	—	Form of Option Award Agreement (Management) for 2016 Omnibus Incentive Plan
10.6	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	10.6	—	Form of Restricted Stock Unit Award Agreement (Management) for 2016 Omnibus Incentive Plan
10.7	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	10.7	—	Form of Restricted Stock Unit Award Agreement (Director) for 2016 Omnibus Incentive Plan
10.8	001-38086	10.8	—	Form of Performance Stock Unit

Exhibits	Previously Filed With File Number*	As Exhibit		
10.12	001-38086 Form 10-K (Year ended December 31, 2020) (filed on February 26, 2021)	10.13	—	Amendment No. 1 to the Vistra Equity Deferred Compensation Plan, dated effective as of February 24, 2021
10.13	001-38086 Form 8-K (filed May 4, 2018)	10.1	—	Amended and Restated Employment Agreement, dated as of May 1, 2018, between Curtis A. Morgan and Vistra Energy Corp. (now known as Vistra Corp.)
10.14	001-38086 Form 8-K (filed March 21, 2022)	10.1	—	Transition and Advisory Agreement, dated as of March 20, 2022, between Curtis A. Morgan and Vistra Corp.
10.15	**		—	Second Amended and Restated Employment Agreement, dated March 20, 2022, between James A. Burke and Vistra Corp.
10.16	**		—	Employment Agreement, dated as of July 20, 2022, between Kristopher E. Moldovan, Vistra Corp. and Vistra Corporate Services Company
10.17	**		—	Amended and Restated Employment Agreement, dated as of May 5, 2022, between Stephanie Zapata Moore, Vistra Corp. and Vistra Corporate Services Company
10.18	**		—	Amended and Restated Employment Agreement, dated as of May 5, 2022, between Carrie Lee Kirby, Vistra Corp. and Vistra Corporate Services Company
10.19	**		—	Amended and Restated Employment Agreement, dated as of May 5, 2022, between Scott A. Hudson, Vistra Corp. and Vistra Corporate Services Company
10.20	**		—	Amended and Restated Employment Agreement, dated as of May 5, 2022, between Stephen J. Muscato, Vistra Corp. and Vistra Corporate Services Company
10.21	**		—	Employment Agreement, dated as of August 23, 2022, between Stacey Doré, Vistra Corp. and Vistra Corporate Services Company
10.22	001-38086 Form 10-K (Year ended December 31, 2022) (filed on March 1, 2023)	10.22	—	Form of indemnification agreement with directors and officers

Exhibits		Previously Filed With File Number*	As Exhibit			
10.27		001-38086 Form 8-K (filed August 17, 2017)	10.1	—		Fourth Amendment to Credit Agreement, dated as of August 17, 2017 (effective August 17, 2017), by and among Deutsche Bank AG New York Branch, Vistra Operations Company LLC, Vistra Intermediate Company LLC and the other Credit Parties and Lenders party thereto.
10.28		001-38086 Form 8-K (filed December 14, 2017)	10.1	—		Fifth Amendment to Credit Agreement, dated as of December 14, 2017 (effective December 14, 2017), by and among Deutsche Bank AG New York Branch, Vistra Operations Company LLC, Vistra Intermediate Company LLC and the other Credit Parties and Lenders party thereto.
10.29		001-38086 Form 8-K (filed February 22, 2018)	10.1	—		Sixth Amendment to Credit Agreement, dated as of February 20, 2018 (effective February 20, 2018), by and among Deutsche Bank AG New York Branch, Vistra Operations Company LLC, Vistra Intermediate Company LLC and the other Credit Parties and Lenders party thereto.
10.30		001-38086 Form 8-K (filed June 15, 2018)	10.1	—		Seventh Amendment to Credit Agreement, dated as of June 14, 2018, by and among Vistra Operations Company LLC, Vistra Intermediate Company LLC, the other Credit Parties party thereto, Credit Suisse and Citibank, N.A. as the 2018 Incremental Term Loan Lenders, the various other Lenders party thereto, Credit Suisse as Successor Administrative Agent and as Successor Collateral Agent, and Delaware Trust Company, as Collateral Trustee.
10.31		001-38086 Form 8-K (filed April 4, 2019)	10.4	—		Eighth Amendment to Credit Agreement, dated March 29, 2019, by and among Vistra Operations Company LLC, Vistra Intermediate Company LLC, the other Credit Parties (as defined in the Vistra Operations Credit Agreement) party thereto, Bank of Montreal, Chicago Branch, as new Revolving Loan Lender, Revolving Letter of Credit Issuer and Joint Lead Arranger, the various other Lenders and Letter of Credit Issuers party thereto, and Credit Suisse as Administrative Agent and Collateral Agent
10.32		001-38086 Form 8-K (filed May 29,	10.1	—		Ninth Amendment to Credit Agreement, dated May 29, 2019, by and among Vistra Operations

Exhibits		Previously Filed With File Number*	As Exhibit			
10.35		001-38086 Form 10-Q (Quarter ended September 30, 2022) (filed on November 4, 2022)	10.3	—		Twelfth Amendment to the Credit Agreement, dated July 18, 2022, by and among Vistra Operations Company LLC (as Borrower), Vistra Intermediate Company LLC (as Holdings), the other Credit Parties (as defined in the Credit Agreement) party thereto, financial institutions, Revolving Credit Lenders, and Revolving Letter of Credit Issuers (in each case as defined in the Credit Agreement) party thereto, and Credit Suisse AG, Cayman Islands Branch (as Administrative Agent and as Collateral Agent)
10.36		001-38086 Form 10-Q (Quarter ended June 30, 2023) (filed on August 9, 2023)	10.1	—		Thirteenth Amendment to the Credit Agreement, dated April 28, 2023, by and among Vistra Operations Company LLC (as Borrower), Vistra Intermediate Company LLC (as Holdings), the other Credit Parties (as defined in the Credit Agreement) party thereto, financial institutions, Revolving Credit Lenders, and Revolving Letter of Credit Issuers (in each case as defined in the Credit Agreement) party thereto, and Credit Suisse AG, Cayman Islands Branch (as Administrative Agent and as Collateral Agent)
10.37		001-38086 Form 10-Q (Quarter ended September 30, 2023) (filed on November 7, 2023)	10.1	—		Fourteenth Amendment to the Credit Agreement, dated September 26, 2023, by and among Vistra Operations Company LLC (as Borrower), Vistra Intermediate Company LLC (as Holdings), the other Credit Parties (as defined in the Credit Agreement) party thereto, financial institutions, Revolving Credit Lenders, and Revolving Letter of Credit Issuers (in each case as defined in the Credit Agreement) party thereto, and Credit Suisse AG, Cayman Islands Branch (as Administrative Agent and as Collateral Agent)
10.38		001-38086 Form 8-K (filed on December 26, 2023)	10.1	—		Fifteenth Amendment to the Credit Agreement, dated December 20, 2023, by and among Vistra Operations Company LLC (as Borrower), Vistra Intermediate Company LLC (as Holdings), the 2023 Incremental Term Loan Lender, the other Credit Parties (as defined in the Credit Agreement) party thereto, the other lenders party thereto, and Credit Suisse AG, Cayman Islands

Exhibits	Previously Filed With File Number*	As Exhibit		
10.45	001-38086 Form 10-Q (Quarter ended June 30, 2022) (filed on August 5, 2022)	10.4	—	Second Amendment to Credit Agreement, dated as of May 26, 2022, among Vistra Operations Company LLC, as Borrower, Vistra Intermediate Company LLC, as Holdings, Citibank, N.A., as Administrative Agent and as Collateral Agent, and the other lenders party thereto
10.46	001-38086 Form 10-Q (Quarter ended June 30, 2022) (filed on August 5, 2022)	10.5	—	Third Amendment to Credit Agreement, dated as of June 8, 2022, among Vistra Operations Company LLC, as Borrower, Vistra Intermediate Company LLC, as Holdings, Citibank, N.A., as Administrative Agent and as Collateral Agent, and the other lenders party thereto
10.47	001-38086 Form 10-K (Year ended December 31, 2022) (filed on March 1, 2023)	10.72	—	Fourth Amendment to Credit Agreement, dated as of October 5, 2022, among Vistra Operations Company LLC, as Borrower, Vistra Intermediate Company LLC, as Holdings, Citibank, N.A., as Administrative Agent and as Collateral Agent, and the other lenders party thereto
10.48	001-38086 Form 10-K (Year ended December 31, 2022) (filed on March 1, 2023)	10.73	—	Fifth Amendment to Credit Agreement, dated as of October 21, 2022, among Vistra Operations Company LLC, as Borrower, Vistra Intermediate Company LLC, as Holdings, Citibank, N.A., as Administrative Agent and as Collateral Agent, and the other lenders party thereto
10.49	001-38086 Form 10-Q (Quarter ended September 30, 2023) (filed on November 7, 2023)	10.2	—	Sixth Amendment to Credit Agreement, dated as of September 26, 2023, among Vistra Operations Company LLC, as Borrower, Vistra Intermediate Company LLC, as Holdings, Citibank, N.A., as Administrative Agent and as Collateral Agent, and the other lenders party thereto
10.50	001-38086 Form 10-Q (Quarter ended September 30, 2023) (filed on November 7, 2023)	10.3	—	Seventh Amendment to Credit Agreement, dated as of October 4, 2023, among Vistra Operations Company LLC, as Borrower, Vistra Intermediate Company LLC, as Holdings, Citibank, N.A., as Administrative Agent and as Collateral Agent, and the other lenders party thereto
	Other Material Contracts			

Exhibits	Previously Filed With File Number*	As Exhibit		
10.55	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.14	—	Tax Matters Agreement, by and among TEX Energy LLC (now known as Vistra Corp.), EFH Corp., Energy Future Intermediate Holding Company LLC, EFI Finance Inc. and EFH Merger Co. LLC, dated as of October 3, 2016
10.56	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.15	—	Transition Services Agreement, by and between Energy Future Holdings Corp. and TEX Operations Company LLC (now known as Vistra Operations Company LLC), dated as of October 3, 2016
10.57	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.16	—	Separation Agreement, by and between Energy Future Holdings Corp., TEX Energy LLC (now known as Vistra Corp.) and TEX Operations Company LLC (now known as Vistra Operations LLC), dated as of October 3, 2016
10.58	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.17	—	Purchase and Sale Agreement, dated as of November 25, 2015, by and between La Frontera Ventures, LLC and Luminant Holding Company LLC
10.59	333-215288 Amendment No. 2 to Form S-1 (filed April 5, 2017)	10.18	—	Amended and Restated Split Participant Agreement, by and between Oncor Electric Delivery Company LLC (f/k/a TXU Electric Delivery Company) and TEX Operations Company LLC (now known as Vistra Operations Company LLC), dated as of October 3, 2016
10.60	001-38086 Form 8-K (filed July 7, 2017)	10(a)	—	Asset Purchase Agreement, dated as of July 5, 2017, by and among Odessa-Ector Power Partners, L.P., La Frontera Holdings, LLC, Vistra Operations Company LLC, Koch Resources, LLC
10.61	001-38086 Form 8-K (filed March 7, 2023)	10.1	—	Form of Support Agreement, dated March 6, 2023
10.62	001-38086 Form 8-K (filed March 7, 2023)	10.2	—	Form of Contribution and Exchange Agreement, dated March 6, 2023
10.63	001-38086 Form 8-K (filed on October 16, 2020)	10.1	—	Master Framework Agreement, dated as of October 9, 2020, by and among TXU Energy Retail Company LLC, as seller and seller party agent, certain originators named therein, and MUFG Bank,

Exhibits	Previously Filed With File Number*	As Exhibit		
10.68	001-38086 Form 8-K (filed on October 16, 2020)	10.2	—	Master Repurchase Agreement, dated as of October 9, 2020, between TXU Energy Retail Company LLC and MUFG Bank, Ltd.
10.69	001-38086 Form 10-Q (Quarter ended September 30, 2021) (filed on November 5, 2021)	10.3	—	Amendment No. 1 to Master Repurchase Agreement, dated as of August 3, 2021, between TXU Energy Retail Company LLC and MUFG Bank, Ltd.
10.70	001-38086 Form 8-K (filed on December 28, 2020)	10.1	—	Joinder Agreement, dated as of December 21, 2020, among TXU Energy Retail company LLC, as seller party agent, Vistra Operations Company LLC, as guarantor, certain originators named therein, and MUFG Bank, Ltd., as buyer
10.71	001-38086 Form 10-K (Year ended December 31, 2021) (filed on February 25, 2022)	10.62	—	Amendment No. 2 to Master Repurchase Agreement, dated as of December 30, 2021, between TXU Energy Retail Company LLC and MUFG Bank, Ltd.
10.72	001-38086 Form 8-K (filed on July 17, 2023)	10.2	—	Amendment No. 3 to Master Repurchase Agreement, dated as of July 11, 2023, by and among TXU Energy Retail Company LLC, as seller and MUFG Bank, Ltd., as buyer
(21)	**Subsidiaries of the Registrant**			
21.1	**		—	Significant Subsidiaries of Vistra Corp.
(23)	**Consent of Experts**			
23.1	**		—	Consent of Deloitte & Touche LLP
(31)	**Rule 13a-14(a) / 15d-14(a) Certifications**			
31.1	**		—	Certification of James A. Burke, principal executive officer of Vistra Corp., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	**		—	Certification of Kristopher E. Moldovan, principal financial officer of Vistra Corp., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
(32)	**Section 1350 Certifications**			
32.1	***		—	Certification of James A. Burke, principal executive officer of Vistra Corp., pursuant to U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	***		—	Certification of Kristopher E.

Exhibits	Previously Filed With File Number*	As Exhibit		
101.SCH	**		—	XBRL Taxonomy Extension Schema Document
101.CAL	**		—	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	**		—	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	**		—	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	**		—	XBRL Taxonomy Extension Presentation Linkbase Document
104			—	The Cover Page Interactive Data File does not appear in Exhibit 104 because its XBRL tags are embedded within the Inline XBRL document.

* Incorporated herein by reference
** Filed herewith
*** Furnished herewith

Item 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Vistra Corp. has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

		VISTRA CORP.	
Date:	February 28, 2024	By	/s/ JAMES A. BURKE
			James A. Burke (President and Chief Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of Vistra Corp. and in the capacities and on the date indicated.

Signature	Title	Date
/s/ JAMES A. BURKE	Principal Executive Officer and Director	February 28, 2024
(James A. Burke, President and Chief Executive Officer)		
/s/ KRISTOPHER E. MOLDOVAN	Principal Financial Officer	February 28, 2024
(Kristopher E. Moldovan, Chief Financial Officer)		
/s/ MARGARET MONTEMAYOR	Principal Accounting Officer	February 28, 2024
(Margaret Montemayor, Senior Vice President, Chief Accountant and Controller)		
/s/ SCOTT B. HELM	Chairman of the Board and Director	February 28, 2024
(Scott B. Helm, Chairman of the Board)		
/s/ HILARY E. ACKERMANN	Director	February 28, 2024
(Hilary E. Ackermann)		
/s/ ARCILIA C. ACOSTA	Director	February 28, 2024
(Arcilia C. Acosta)		
/s/ GAVIN R. BAIERA	Director	February 28, 2024
(Gavin R. Baiera)		
/s/ PAUL M. BARBAS	Director	February 28, 2024
(Paul M. Barbas)		
/s/ LISA CRUTCHFIELD	Director	February 28, 2024
(Lisa Crutchfield)		
/s/ BRIAN K. FERRAIOLI	Director	February 28, 2024
(Brian K. Ferraioli)		
/s/ JEFF D. HUNTER	Director	February 28, 2024
(Jeff D. Hunter)		
/s/ JULIE A. LAGACY	Director	February 28, 2024
(Julie A. Lagacy)		
/s/ JOHN R. SULT	Director	February 28, 2024
(John R. Sult)		