UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-K

(Mark One)

☒ 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	Registrant; State of Incorporation; Address; and Telephone Number	IRS Employer Identification No.
	image0a14.jpg	
001-09057	WEC ENERGY GROUP, INC. (A Wisconsin Corporation) 231 West Michigan Street P.O. Box 1331 Milwaukee, WI 53201 (414) 221-2345	39-1391525

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Trading Symbol(s)	Name of Each Exchange on Which Registered
Common Stock, $.01 Par Value	WEC	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 ☐

Indicate 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 ☒

The aggregate market value of the common stock of WEC Energy Group, Inc. held by non-affiliates was $27.8 billion based upon the reported closing price of such securities as of June 30, 2023.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date (January 31, 2024):

Common Stock, $.01 par value, 315,561,510 shares outstanding

Documents incorporated by reference:

Portions of WEC Energy Group, Inc.'s Definitive Proxy Statement on Schedule 14A for its Annual Meeting of Shareholders, to be held on May 9, 2024, are incorporated by reference into Part III hereof.

WEC ENERGY GROUP, INC.
ANNUAL REPORT ON FORM 10-K
For the Year Ended December 31, 2023
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GLOSSARY OF TERMS AND ABBREVIATIONS

The abbreviations and terms set forth below are used throughout this report and have the meanings assigned to them below:

Subsidiaries and Affiliates	
ATC	American Transmission Company LLC
ATC Holdco	ATC Holdco LLC
ATC Holding	ATC Holding LLC
Bishop Hill III	Bishop Hill Energy III LLC
Blooming Grove	Blooming Grove Wind Energy Center LLC
Bluewater	Bluewater Natural Gas Holding, LLC
Bluewater Gas Storage	Bluewater Gas Storage, LLC
Coyote Ridge	Coyote Ridge Wind, LLC
Integrys	Integrys Holding, Inc.
Jayhawk	Jayhawk Wind, LLC
MERC	Minnesota Energy Resources Corporation
MGU	Michigan Gas Utilities Corporation
NSG	North Shore Gas Company
PDL	WPS Power Development, LLC
PELLC	Peoples Energy, LLC
PGL	The Peoples Gas Light and Coke Company
Samson I	Samson I Solar Energy Center LLC
Sapphire Sky	Sapphire Sky Wind Energy LLC
Tatanka Ridge	Tatanka Ridge Wind, LLC
Thunderhead	Thunderhead Wind Energy LLC
UMERC	Upper Michigan Energy Resources Corporation
Upstream	Upstream Wind Energy LLC
WBS	WEC Business Services LLC
WE	Wisconsin Electric Power Company
We Power	W.E. Power, LLC
WEC Energy Group	WEC Energy Group, Inc.
WECC	Wisconsin Energy Capital Corporation
WECI	WEC Infrastructure LLC
WECI Wind Holding I	WEC Infrastructure Wind Holding I LLC
WECI Wind Holding II	WEC Infrastructure Wind Holding II LLC
WEPCo Environmental Trust	WEPCo Environmental Trust Finance I, LLC
WG	Wisconsin Gas LLC
Wispark	Wispark LLC
Wisvest	Wisvest LLC
WPS	Wisconsin Public Service Corporation
WRPC	Wisconsin River Power Company

Federal and State Regulatory Agencies	
Army Corps	United States Army Corps of Engineers
CBP	United States Customs and Border Protection Agency
DOC	United States Department of Commerce
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
ICC	Illinois Commerce Commission
IRS	United States Internal Revenue Service

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Accounting Terms

AFUDC	Allowance for Funds Used During Construction
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
CWIP	Construction Work in Progress
FASB	Financial Accounting Standards Board
GAAP	Generally Accepted Accounting Principles
LIFO	Last-In, First-Out
OPEB	Other Postretirement Employee Benefits
VIE	Variable Interest Entity

Environmental Terms

Act 141	2005 Wisconsin Act 141
BATW	Bottom Ash Transport Water
BTA	Best Technology Available
CAA	Clean Air Act
CASAC	Clean Air Scientific Advisory Committee
CCR	Coal Combustion Residual
CO_2	Carbon Dioxide
CWA	Clean Water Act
ELG	Steam Electric Effluent Limitation Guidelines
FGD	Flue Gas Desulfurization
GHG	Greenhouse Gas
LDC	Local Natural Gas Distribution Company
MATS	Mercury and Air Toxics Standards
NAAQS	National Ambient Air Quality Standards
NOV	Notice of Violation
NOx	Nitrogen Oxide
NSPS	New Source Performance Standards
PCB	Polychlorinated Biphenyl
PM	Particulate Matter
SO_2	Sulfur Dioxide
WOTUS	Waters of the United States
WPDES	Wisconsin Pollutant Discharge Elimination System
ZLD	Zero Liquid Discharge

Measurements

Bcf	Billion Cubic Feet
Dth	Dekatherm
lb/MMBtu	Pound Per Million British Thermal Unit
MDth	One Thousand Dekatherms
MW	Megawatt
MWh	Megawatt-hour
µg/m3	Micrograms Per Cubic Meter

Other Terms and Abbreviations

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Chicago, IL-IN-WI	Chicago, Illinois, Indiana, and Wisconsin
Compensation Committee	Compensation Committee of the Board of Directors
CSIRT	Cybersecurity Incident Response Team
D.C. Circuit Court of Appeals	United States Court of Appeals for the District of Columbia Circuit
Darien	Darien Solar Park
DER	Distributed Energy Resource
DRER	Dedicated Renewable Energy Resource
Enterprise Security Director	Director of Enterprise Security & Compliance
ERGS	Elm Road Generating Station
ER 1	Elm Road Generating Station Unit 1
ER 2	Elm Road Generating Station Unit 2
ERSC	Enterprise Risk Steering Committee
ESG Progress Plan	WEC Energy Group's Capital Investment Plan for Efficiency, Sustainability, and Growth for 2024-2028
ETB	Environmental Trust Bond
EV	Electric Vehicle
Exchange Act	Securities Exchange Act of 1934, as amended
Executive Order 13990	Executive Order 13990 of January 20, 2021 - Protecting Public Health and the Environment and Restoring Science To Tackle the Climate Crisis
Forward Wind	Forward Wind Energy Center
FTR	Financial Transmission Right
GCRM	Gas Cost Recovery Mechanism
High Noon	High Noon Solar Energy Center
Holding Company Act	Wisconsin Utility Holding Company Act
IRA	Inflation Reduction Act
IT/OT	Information Technology and Operational Technology
ITC	Investment Tax Credit
Koshkonong	Koshkonong Solar Park
LIBOR	London Interbank Offered Rate
LMP	Locational Marginal Price
LNG	Liquefied Natural Gas
Maple Flats	Maple Flats Solar Energy Center
MG&E	Madison Gas and Electric Company
MISO	Midcontinent Independent System Operator, Inc.
MISO Energy Markets	MISO Energy and Operating Reserves Market
MRP	Main Replacement Program
NYMEX	New York Mercantile Exchange
OCPP	Oak Creek Power Plant
Omnibus Stock Incentive Plan	WEC Energy Group Omnibus Stock Incentive Plan, Amended and Restated, Effective as of May 6, 2021
Paris	Paris Solar-Battery Park
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPP	Presque Isle Power Plant
Point Beach	Point Beach Nuclear Power Plant
PPA	Power Purchase Agreement

RNG	Renewable Natural Gas
ROE	Return on Equity
RTO	Regional Transmission Organization
S&P	Standard & Poor's
SIP	State Implementation Plan
SMP	Safety Modernization Program
SOFR	Secured Overnight Financing Rate
SPP	Southwest Power Pool, Inc.
SSR	System Support Resource
Supreme Court	United States Supreme Court
Tax Legislation	Tax Cuts and Jobs Act of 2017
TCR	Transmission Congestion Right
Tilden	Tilden Mining Company
TPTFA	Third-Party Transaction Fee Adjustment
Two Creeks	Two Creeks Solar Park
UEA	Uncollectible Expense Adjustment
UFLPA	Uyghur Forced Labor Prevention Act
VAPP	Valley Power Plant
West Riverside	West Riverside Energy Center
Whitewater	Whitewater Cogeneration Facility
WPL	Wisconsin Power and Light Company
WRO	Withhold Release Order
WUA	Wisconsin Utilities Association

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

In this report, we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, and future events or performance. These statements are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Exchange Act. Readers are cautioned not to place undue reliance on these forward-looking statements. Forward-looking statements may be identified by reference to a future period or periods or by the use of terms such as "anticipates," "believes," "could," "estimates," "expects," "forecasts," "goals," "guidance," "intends," "may," "objectives," "plans," "possible," "potential," "projects," "seeks," "should," "targets," "will," or variations of these terms.

Forward-looking statements include, among other things, statements concerning management's expectations and projections regarding earnings, completion of capital projects, sales and customer growth, rate actions and related filings with regulatory authorities, environmental and other regulations, including associated compliance costs, legal proceedings, dividend payout ratios, effective tax rates, pension and OPEB plans, fuel costs, sources of electric energy supply, coal and natural gas deliveries, remediation costs, climate-related matters, our ESG Progress Plan, liquidity and capital resources, and other matters.

Forward-looking statements are subject to a number of risks and uncertainties that could cause our actual results to differ materially from those expressed or implied in the statements. These risks and uncertainties include those described in Item 1A. Risk Factors and those identified below:

- Factors affecting utility and non-utility energy infrastructure operations such as catastrophic weather-related damage, environmental incidents, unplanned facility outages and repairs and maintenance, and electric transmission or natural gas pipeline system constraints;

- Factors affecting the demand for electricity and natural gas, including political or regulatory developments, varying, adverse, or unusually severe weather conditions, including those caused by climate change, changes in economic conditions, customer growth and declines, commodity prices, energy conservation efforts, and continued adoption of distributed generation by customers;

- The timing, resolution, and impact of rate cases and negotiations, including recovery of deferred and current costs and the ability to earn a reasonable return on investment, and other regulatory decisions impacting our regulated operations;

- The impact of federal, state, and local legislative and/or regulatory changes, including changes in rate-setting policies or procedures, the results of recent rate orders, deregulation and restructuring of the electric and/or natural gas utility industries, transmission or distribution system operation, the approval process for new construction, reliability standards, pipeline integrity and safety standards, allocation of energy assistance, energy efficiency mandates, electrification initiatives and other efforts to reduce the use of natural gas, and tax laws, including those that affect our ability to use PTCs and ITCs, as well as changes in the interpretation and/or enforcement of any laws or regulations by regulatory agencies;

- Federal, state, and local legislative and regulatory changes relating to the environment, including climate change and other environmental regulations impacting generation facilities and renewable energy standards, the enforcement of these laws and regulations, changes in the interpretation of regulations or permit conditions by regulatory agencies, and the recovery of associated remediation and compliance costs;

- The ability to obtain and retain customers, including wholesale customers, due to increased competition in our electric and natural gas markets from retail choice and alternative electric suppliers, and continued industry consolidation;

- The timely completion of capital projects within budgets and the ability to recover the related costs through rates;

- The impact of changing expectations and demands of our customers, regulators, investors, and other stakeholders, including focus on environmental, social, and governance concerns;

- The risk of delays and shortages, and increased costs of equipment, materials, or other resources that are critical to our business operations and corporate strategy, as a result of supply chain disruptions (including disruptions from rail congestion), inflation, and other factors;

- The impact of public health crises, including epidemics and pandemics, on our business functions, financial condition, liquidity, and results of operations;

- Factors affecting the implementation of our CO_2 emission and/or methane emission reduction goals and opportunities and actions related to those goals, including related regulatory decisions, the cost of materials, supplies, and labor, technology advances, the feasibility of competing generation projects, and our ability to execute our capital plan;

- The financial and operational feasibility of taking more aggressive action to further reduce GHG emissions in order to limit future global temperature increases;

- The risks associated with inflation and changing commodity prices, including natural gas and electricity;

- The availability and cost of sources of natural gas and other fossil fuels, purchased power, materials needed to operate environmental controls at our electric generating facilities, or water supply due to high demand, shortages, transportation problems, nonperformance by electric energy or natural gas suppliers under existing power purchase or natural gas supply contracts, or other developments;

- Any impacts on the global economy, including from sanctions, and impacts on supply chains and fuel prices, generally, from ongoing, expanding, or escalating regional conflicts, including those in Ukraine, Israel, and parts of the Middle East;

- Changes in credit ratings, interest rates, and our ability to access the capital markets, caused by volatility in the global credit markets, our capitalization structure, and market perceptions of the utility industry, us, or any of our subsidiaries;

- Costs and effects of litigation, administrative proceedings, investigations, settlements, claims, and inquiries;

- The direct or indirect effect on our business resulting from terrorist or other physical attacks and cybersecurity intrusions, as well as the threat of such incidents, including the failure to maintain the security of personally identifiable information, the associated costs to protect our utility assets, technology systems, and personal information, and the costs to notify affected persons to mitigate their information security concerns and to comply with state notification laws;

- Restrictions imposed by various financing arrangements and regulatory requirements on the ability of our subsidiaries to transfer funds to us in the form of cash dividends, loans or advances, that could prevent us from paying our common stock dividends, taxes, and other expenses, and meeting our debt obligations;

- The risk of financial loss, including increases in bad debt expense, associated with the inability of our customers, counterparties, and affiliates to meet their obligations;

- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading markets and fuel suppliers and transporters;

- The financial performance of ATC and its corresponding contribution to our earnings;

- The investment performance of our employee benefit plan assets, as well as unanticipated changes in related actuarial assumptions, which could impact future funding requirements;

- Factors affecting the employee workforce, including loss of key personnel, internal restructuring, work stoppages, and collective bargaining agreements and negotiations with union employees;

- Advances in technology, and related legislation or regulation supporting the use of that technology, that result in competitive disadvantages and create the potential for impairment of existing assets;

- Risks related to our non-utility renewable energy facilities, including unfavorable weather, changes in the financial performance and/or creditworthiness of counterparties to the off-take agreements, changes in demand based on lower prices for alternative energy sources, the ability to replace expiring PPAs under acceptable terms, risks of rights related to property on which our projects are located but we do not own, the availability of reliable interconnection and electricity grids, and exposure to the rules and procedures of the power markets in which these facilities are located;

- The risk associated with the values of goodwill and other long-lived assets, including intangible assets, and equity method investments, including the current impairment of capital costs in Illinois; and possible future impairments of other assets;

- Potential business strategies to acquire and dispose of assets or businesses, or portions thereof, which cannot be assured to be completed timely or within budgets, and legislative or regulatory restrictions or caps on non-utility acquisitions, investments or projects, including the State of Wisconsin's public utility holding company law;

- The timing and outcome of any audits, disputes, and other proceedings related to taxes;

- The effect of accounting pronouncements issued periodically by standard-setting bodies; and

- Other considerations disclosed elsewhere herein and in other reports we file with the SEC or in other publicly disseminated written documents.

Except as may be required by law, we expressly disclaim any obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events, or otherwise.

PART I

ITEM 1. BUSINESS

A. INTRODUCTION

In this report, when we refer to "WEC Energy Group," "the Company," "us," "we," "our," or "ours," we are referring to WEC Energy Group, Inc. and all of its subsidiaries. The term "utility" refers to the regulated activities of the electric and natural gas utility companies, while the term "non-utility" refers to the activities of the electric and natural gas companies that are not regulated, as well as We Power and Bluewater. The term "nonregulated" refers to activities at WECI, which holds interests in several renewable generating facilities, WEC Energy Group holding company, the Integrys holding company, the PELLC holding company, Wispark, Wisvest, WECC, WBS, and PDL. References to "Notes" are to the Notes to Consolidated Financial Statements included in this Annual Report on Form 10-K.

For more information about our business operations, see Note 22, Segment Information, and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations. For information about our business strategy, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Corporate Developments.

WEC Energy Group, Inc.

We were incorporated in the state of Wisconsin in 1981 and became a diversified holding company in 1986. We maintain our principal executive offices in Milwaukee, Wisconsin. On June 29, 2015, we acquired 100% of the outstanding common shares of Integrys and changed our name to WEC Energy Group, Inc. Our wholly owned subsidiaries provide or invest in regulated natural gas and electricity, and renewable energy, as well as nonregulated renewable energy. We have an approximately 60% equity interest in ATC (an electric transmission company operating in Illinois, Michigan, Minnesota, and Wisconsin). At December 31, 2023, we had six reportable segments, which are discussed below. For additional information about our reportable segments, see Note 22, Segment Information.

Available Information

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports are made available on our website, www.wecenergygroup.com, free of charge, as soon as reasonably practicable after they are filed with or furnished to the SEC. The SEC maintains an Internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at www.sec.gov.

Investors should note that WEC Energy Group announces material financial information in SEC filings, press releases, and public conference calls. In accordance with SEC guidelines, WEC Energy Group also uses the "Investors" tab on its website, www.wecenergygroup.com, to communicate with investors. It is possible that the financial and other information posted there could be deemed material information. The information on WEC Energy Group's website is not part of this document.

B. UTILITY ENERGY OPERATIONS

Wisconsin Segment

The Wisconsin segment includes the electric and natural gas utility operations of WE, WPS, WG, and UMERC.

Electric Utility Operations

Our electric utility operations include the operations of WE, WPS, and UMERC.

- WE generates and distributes electric energy to customers located in southeastern Wisconsin (including the metropolitan Milwaukee area), east central Wisconsin, and northern Wisconsin.

- WPS generates and distributes electric energy to customers located in northeastern and central Wisconsin.

- UMERC generates and distributes electric energy to customers, including one iron ore mine owned by Tilden, located in the Upper Peninsula of Michigan.

Operating Revenues

For information about our operating revenues disaggregated by customer class for the years ended December 31, 2023, 2022, and 2021, see Note 1(d), Operating Revenues, and Note 4, Operating Revenues.

Electric Sales

Our electric energy deliveries included supply and distribution sales to retail, wholesale, and resale customers, and distribution sales to those customers who switched to an alternative electric supplier in the Upper Peninsula of Michigan. In 2023, retail revenues accounted for 92.9% of total electric operating revenues, wholesale revenues accounted for 2.4% of total electric operating revenues, and resale revenues accounted for 3.9% of total electric operating revenues. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Wisconsin Segment Contribution to Net Income Attributed to Common Shareholders for information on MWh sales by customer class.

Our electric utilities are authorized to provide retail electric service in designated territories in the state of Wisconsin, as established by indeterminate permits and boundary agreements with other utilities, and in certain territories in the state of Michigan pursuant to franchises granted by municipalities.

We provide wholesale electric service to various customers, including electric cooperatives, municipal joint action agencies, other investor-owned utilities, municipal utilities, and energy marketers.

The majority of our sales for resale are sold into an energy market operated by MISO at market rates based on the availability of our generation and market demand. Retail fuel costs are reduced by the amount that revenue exceeds the cost of sales derived from these opportunity sales.

Our electric utilities buy and sell electric power by participating in the MISO Energy Markets. The cost of our individual generation offered into the MISO Energy Markets compared to our competitors affects how often our generating units are dispatched and whether we buy or sell power. For more information on the MISO Energy Markets, see E. Regulation.

Steam Sales

WE has a steam utility that generates, distributes, and sells steam supplied by the VAPP to customers in metropolitan Milwaukee, Wisconsin. Steam is used by customers for processing, space heating, domestic hot water, and humidification. Annual sales of steam fluctuate from year to year based on system growth and variations in weather conditions.

Electric Sales Forecast

Our service territory experienced slightly lower weather-normalized retail electric sales in 2023, compared with 2022, due to lower sales to large commercial and industrial customers. We currently forecast retail electric sales volumes, excluding the Tilden mine located in the Upper Peninsula of Michigan, to remain relatively flat for 2024, assuming normal weather.

Customers

	Year Ended December 31		
(in thousands)	**2023**	**2022**	**2021**
Electric customers – end of year			
Residential	**1,487.9**	1,471.4	1,460.4
Small commercial and industrial	**179.0**	176.9	175.8
Large commercial and industrial	**0.8**	0.9	0.8
Wholesale and other	**1.6**	1.6	1.6
Total electric customers – end of year	**1,669.3**	1,650.8	1,638.6
Steam customers – end of year	**0.4**	0.4	0.4

Electric Commercial and Industrial Retail Customers

We provide electric utility service to a diversified base of customers in industries such as metals and other manufacturing, paper, governmental, food products, and health services.

Electric Generation and Supply Mix

Our electric supply strategy is to provide our customers with energy from a diverse generation portfolio that is expected to balance a stable, reliable, and affordable supply of electricity with environmental stewardship. Through our participation in the MISO Energy Markets, we supply a significant amount of electricity to our customers from generation that we own. We supplement our internally generated power supply with long-term PPAs, including the Point Beach PPA discussed under the heading "Power Purchase Commitments," and through spot purchases in the MISO Energy Markets. We also sell excess power supply into the MISO Energy Markets when it is economical, which reduces net fuel costs by offsetting costs of purchased power. All options, including owned generation resources and purchased power opportunities, are continually evaluated on a real time basis to select and dispatch the lowest-cost resources available to meet system load requirements.

The table below indicates our sources of electric energy supply as a percentage of sales for the three years ended December 31, as well as estimates for 2024:

	Estimate [1]	**Actual**		
	2024	**2023**	**2022**	**2021**
Company-owned generation:				
Coal	27.7 %	**29.0 %**	29.4 %	35.5 %
Natural gas:				
Combined cycle	30.8 %	**28.7 %**	27.2 %	24.6 %
Steam turbine	0.7 %	**0.9 %**	1.0 %	0.8 %
Natural gas/oil peaking units	6.8 %	**5.5 %**	3.7 %	3.1 %
Renewables [2]	7.0 %	**5.5 %**	5.8 %	4.8 %
Total company-owned generation	73.0 %	**69.6 %**	67.1 %	68.8 %
Power purchase contracts:				
Nuclear	19.7 %	**20.1 %**	19.8 %	19.0 %
Natural gas	— %	**— %**	2.2 %	1.9 %
Renewables [2]	1.8 %	**2.0 %**	1.9 %	1.9 %
Other	— %	**0.1 %**	0.2 %	0.1 %
Total power purchase contracts	21.5 %	**22.2 %**	24.1 %	22.9 %
Purchased power from MISO	5.5 %	**8.2 %**	8.8 %	8.3 %
Total purchased power	27.0 %	**30.4 %**	32.9 %	31.2 %
Total electric utility supply	100.0 %	**100.0 %**	100.0 %	100.0 %

[1] The values included in the estimate assume a natural gas price based on the December 2023 NYMEX.

(2) Includes hydroelectric, biomass, solar, and wind generation.

Electric Generation Facilities

Our generation portfolio is a mix of energy resources having different operating characteristics and fuel sources designed to balance providing energy that is stable, reliable, and affordable with environmental stewardship. We own 8,337 MWs of generation capacity, including wholly owned and jointly owned facilities. We Power's generating units are also included in the generation capacity. Our facilities include natural gas-fired plants, coal-fired plants, and renewable generation. Certain of our natural gas-fired generation units have the ability to burn oil if natural gas is not available due to delivery constraints. For more information about our facilities, see Item 2. Properties.

Environmental Goals

We have announced goals to achieve reductions in carbon emissions from our electric generation fleet by 60% by the end of 2025 and by 80% by the end of 2030, both from a 2005 baseline. As of the end of 2023, our electric generation fleet has achieved a 54% reduction in carbon emissions from the 2005 baseline. We expect to achieve these goals by continuing to make operating refinements, retiring less efficient generating units, and executing our capital plan. Over the longer term, the target for our generation fleet is to be net carbon neutral by 2050.

As part of our path toward these goals, we have started implementing co-firing with natural gas at the ERGS coal-fired units. By the end of 2030, we expect to use coal as a backup fuel only, and we believe we will be in a position to eliminate coal as an energy source by the end of 2032.

Creating a Sustainable Future

Our ESG Progress Plan includes the retirement of older, fossil-fueled generation, to be replaced with zero-carbon-emitting renewables and clean natural gas-fired generation. The retirements will contribute to meeting our goals to reduce CO_2 emissions from our electric generation. When taken together, the retirements and new investments in renewables and clean generation discussed in more detail below, should better balance our supply with our demand, while maintaining reliable, affordable energy for our customers.

We already have retired more than 1,900 MWs of coal-fired generation since the beginning of 2018, which included the 2019 retirement of the PIPP as well as the 2018 retirements of the Pleasant Prairie power plant, the Pulliam power plant, and the jointly-owned Edgewater Unit 4 generating units. See Note 6, Regulatory Assets and Liabilities, for more information related to these power plant retirements. We expect to retire approximately 1,800 MWs of additional fossil-fueled generation by the end of 2031, which includes the planned retirement in 2024-2025 of OCPP Units 5-8, the planned retirement by June 2026 of jointly-owned Columbia Units 1 and 2, and the planned retirement in 2031 of Weston Unit 3. See Note 7, Property, Plant, and Equipment, for more information.

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Corporate Developments for more information on the ESG Progress Plan.

Also see Item 1A. Risk Factors - Risks Related to Legislation and Regulation - Our operations, capital expenditures, and financial results may be affected by the impact of GHG gas legislation, regulation, and emission reduction goals.

Renewable Generation

Our electric utilities meet a portion of their electric generation supply with various renewable energy resources, including wind, solar, hydroelectric, and biomass. This helps our electric utilities work towards our goals of reducing carbon emissions while also maintaining compliance with renewable energy legislation. These renewable energy resources also help us maintain diversity in our generation portfolio, which effectively serves as a price hedge against future fuel costs, and will help mitigate the risk of potential unknown costs associated with any future carbon restrictions for electric generators.

In December 2018, WE received approval from the PSCW for the DRER pilot program, a program designed to allow large commercial and industrial customers to access renewable resources that WE would operate. The DRER pilot is intended to help these larger customers meet their sustainability and renewable energy goals and could add up to 35 MWs of renewables to WE's portfolio. In addition, in July 2023, the PSCW approved the Renewable

Pathway Pilot, which allows WE and WPS commercial and industrial customers to subscribe to a portion of a utility-scale, Wisconsin-based renewable energy generating facility for up to 125 MWs at WE and 40 MWs at WPS.

Wind

In April 2023, WPS, along with an unaffiliated utility, completed the acquisition of Red Barn, a commercially operational utility-scale wind-powered electric generating facility. The project is located in Grant County, Wisconsin, and WPS owns 82 MWs of this project.

Solar and Battery Storage

In December 2023, the construction of Badger Hollow II located in Iowa County, Wisconsin was completed, and the facility became commercially operational. Badger Hollow II is owned by WE and an unaffiliated utility, with WE owning 100 MWs of the facility.

As part of our commitment to invest in additional zero-carbon generation within our Wisconsin segment, we have filed requests to acquire and construct 370 MWs of additional projects, including the following:

- In February 2024, WE and WPS, along with an unaffiliated utility, filed a request with the PSCW to acquire and construct High Noon, a utility-scale solar-powered electric generating facility. The project will be located in Columbia County, Wisconsin and once fully constructed, WE and WPS will collectively own 270 MWs of solar generation of this project. The construction is expected to be completed by the end of 2026.

- In December 2023, UMERC filed a request with the MPSC to acquire and construct Renegade, a utility-scale solar-powered electric generating facility. The project will be located in Delta County, Michigan and once fully constructed UMERC will own 100 MWs of solar generation. The construction is expected to be completed by the end of 2026.

We have also received approvals from the PSCW to invest in 809 MWs of additional projects currently in construction, including the following:

- In April 2023, WE and WPS, along with an unaffiliated utility, received PSCW approval to acquire Koshkonong, a utility-scale solar-powered electric generating facility. The project will be located in Dane County, Wisconsin and once fully constructed, WE and WPS will collectively own 270 MWs of solar generation. The construction is expected to be completed in 2026.

- In December 2022, WE and WPS, along with an unaffiliated utility, received PSCW approval to acquire and construct Darien, a utility-scale solar-powered electric generating facility. The project will be located in Rock and Walworth counties, Wisconsin and once fully constructed, WE and WPS will collectively own 225 MWs of solar generation. The construction is expected to be completed in 2024.

- In January 2022, WE and WPS, along with an unaffiliated utility, received PSCW approval to acquire and construct Paris, a utility-scale solar-powered electric generating facility with a battery energy storage system. The project will be located in Kenosha County, Wisconsin and once fully constructed, WE and WPS will collectively own 180 MWs of solar generation and 99 MWs of battery storage of this project. The construction of the solar portion and battery storage is expected to be completed in 2024 and 2025, respectively.

- In December 2018, WE received approval from the PSCW for the Solar Now pilot program, which is expected to add a total of 35 MWs of solar generation to WE's portfolio, allowing non-profit and government entities, as well as commercial and industrial customers, to site utility owned solar arrays on their property. Under this program, WE has energized 28 Solar Now projects and currently has another one under construction, together totaling more than 30 MWs.

WE and WPS actively review and pursue distribution system interconnected solar projects. WE and WPS partner with proven developers to identify and purchase cost effective solar projects for our customers. These projects are typically ground-mounted modules in the range of 5-10 MWs and are connected to the WE or WPS distribution systems, as applicable.

Currently, WE has 30 MWs of distribution connected projects under contract, which are estimated to go in-service in 2024.

Natural Gas-Fired Generation

In July 2023, WE and WPS completed construction of seven natural gas-fired generation RICE units with a rated capacity of 130 MWs at WPS's Weston power plant site.

In June 2023, WE completed the acquisition of 100 MWs of West Riverside's nameplate capacity, in the first of two potential option exercises. West Riverside is a commercially operational dual fueled combined cycle generation facility in Beloit, Wisconsin, and is operated by an unaffiliated utility. In addition, WPS filed a request with the PSCW in September 2023 to exercise a second option to acquire an additional 100 MWs of West Riverside's nameplate capacity. As it did with the first option, in October 2023, WPS filed for approval to assign its ownership interest pursuant to this second option to WE, with the transaction expected to close in 2024.

In January 2023, WE and WPS completed the acquisition of Whitewater, a commercially operational dual fueled combined cycle generation facility in Whitewater, Wisconsin with a rated capacity of 242.8 MWs.

Other Sustainability Programs

In August 2021, the PSCW approved pilot programs for WE and WPS to install and maintain EV charging equipment for customers at their homes or businesses. The programs provide direct benefits to customers by removing cost barriers associated with installing EV equipment. In October 2021, subject to the receipt of any necessary regulatory approvals, we pledged to expand the EV charging network within the service territories of our electric utilities. In doing so, we joined a coalition of utility companies in a unified effort to make EV charging convenient and widely available throughout the Midwest. The coalition we joined is planning to help build and grow EV charging corridors, enabling the general public to safely and efficiently charge their vehicles.

Electric System Reliability

The PSCW requires us to maintain a planning reserve margin above our projected annual peak demand forecast to help ensure reliability of electric service to our customers. These planning reserve requirements are consistent with the MISO calculated planning reserve margin. In 2008, the PSCW established a 14.5% reserve margin requirement for long-term planning (planning years two through ten). For short-term planning (planning year one), the PSCW requires Wisconsin utilities to follow the planning reserve margin established by MISO. MISO implemented seasonal requirements effective June 1, 2023. The installed capacity reserve margins for the planning year June 1, 2024 through May 31, 2025 are as follows: 16.6% summer (June – August); 26.6% fall (September – November); 41.1% winter (December – February); and 39.5% spring (March – May). MISO's short-term reserve margin requirements experience year-to-year and season-to-season fluctuations, primarily due to changes in the generation resource mix and average forced outage rate of generation within the MISO footprint.

Michigan legislation requires all electric providers to annually demonstrate to the MPSC that they have adequate resources to serve the anticipated needs of their customers for a minimum of four consecutive planning years beginning in the upcoming planning year June 1, 2024, through May 31, 2025. The MPSC has established future planning reserve margin requirements based on the same study conducted by MISO that determines the short-term reserve margin requirements.

In both our Wisconsin and Michigan jurisdictions, we believe that we have adequate capacity through company-owned generation units and power purchase contracts to meet the MISO calculated planning reserve margin during the current planning year. We also fully anticipate that we will have adequate capacity to meet the planning reserve margin requirements for the upcoming planning year in both jurisdictions.

Fuel and Purchased Power Costs

Our retail electric rates in Wisconsin are established by the PSCW and include base amounts for fuel and purchased power costs. The electric fuel rules set by the PSCW generally allow us to defer, for subsequent rate recovery or refund, under- or over-collections of actual fuel and purchased power costs beyond a 2% price variance from the costs included in the rates charged to customers. Prudently incurred fuel and purchased power costs are recovered dollar-for-dollar from our Michigan retail electric customers. For more information about the fuel rules, see E. Regulation.

Our average fuel and purchased power costs per MWh by fuel type, including delivery costs, were as follows for the years ended December 31:

	2023	2022	2021
Coal	**$ 25.80**	$ 25.37	$ 21.06
Natural gas combined cycle	**30.41**	42.11	24.55
Natural gas/oil peaking units	**56.41**	90.22	76.96
Biomass	**87.73**	78.42	86.24
Purchased power	**53.90**	58.78	50.88

WE and WPS purchase coal under long-term contracts, which helps with price stability. Coal and associated transportation services are exposed to volatility in pricing due to changing domestic and world-wide demand for coal and diesel fuel. To mitigate against this volatility risk, WE and WPS have PSCW approval for a hedging program. This program allows them to hedge, over a 60-month period, up to 75% of their potential risks related to rail transportation fuel surcharge exposure. The results of this hedging program, when used, are reflected in the average costs of fuel and purchased power.

We purchase natural gas for our plants on the spot market from natural gas marketers, utilities, and producers, and we arrange for transportation of the natural gas to our plants. We have firm and interruptible transportation, as well as balancing and storage agreements, intended to support our plants' variable usage. WE and WPS also have PSCW approval for a hedging program to mitigate against volatility related to natural gas price risk. This program allows them to hedge, over a 60-month period, up to 75% of their estimated natural gas use for electric generation. The results of this hedging program are reflected in the average costs of natural gas.

Coal Supply

We diversify the coal supply for our electric generating facilities and jointly-owned plants by purchasing coal from several mines in Wyoming and Pennsylvania, as well as from various other states. For 2024, 100% of our total projected coal requirements of 7.1 million tons are contracted under fixed-price contracts. See Note 24, Commitments and Contingencies, for more information on amounts of coal purchases and coal deliveries under contract.

The annual tonnage amounts contracted for the next three years are as follows.

(in thousands)	**Annual Tonnage**
2024	9,275 [1]
2025	3,750
2026	1,400

[1] Coal contracts exceed the total projected requirement due to prior year delivery constraints and forecasted lower operating hours.

Coal Deliveries

All of our coal requirements are expected to be shipped by unit trains that we own or lease under existing transportation agreements. The unit trains transport the coal for electric generating facilities from mines in Wyoming and Pennsylvania. Additional small volume agreements may also be used to supplement the normal coal supply for our facilities. For additional information concerning risks related to coal supply chain disruptions, see the risk factor below.

- Item 1A. Risk Factors – Risks Related to Economic and Market Volatility – We may not be able to obtain an adequate supply of coal, which could limit our ability to operate our coal-fired facilities.

Power Purchase Commitments

We enter into short- and long-term power purchase commitments to meet a portion of our anticipated electric energy supply needs. Excluding planning capacity purchases, our power purchase commitments with unaffiliated parties consist of 1,133 MWs per year for 2024 through 2028. This amount includes 1,033 MWs per year related to a long-term PPA for electricity generated by Point Beach. To procure additional planning capacity, we purchase capacity from the MISO annual auction to ensure that we maintain our compliance with planning reserve requirements as established by the PSCW, MPSC, and MISO.

Natural Gas Utility Operations

WE, WPS, and WG are authorized to provide retail natural gas distribution service in designated territories in the state of Wisconsin, as established by indeterminate permits and boundary agreements with other utilities. Our Wisconsin natural gas utilities operate throughout the state of Wisconsin, including the City of Milwaukee and surrounding areas, northeastern Wisconsin, and in large areas of both central and western Wisconsin. In addition, UMERC is authorized to provide retail natural gas distribution service in designated territories in the Upper Peninsula of Michigan.

Our Wisconsin segment natural gas utilities provide service to residential and commercial and industrial customers. In addition, our Wisconsin segment offers natural gas transportation services to our customers that elect to purchase natural gas directly from a third-party supplier. Major industries served include real estate, food products, governmental, restaurants, and paper. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Wisconsin Segment Contribution to Net Income Attributed to Common Shareholders for information on natural gas sales volumes by customer class in Wisconsin and the Upper Peninsula of Michigan.

Operating Revenues

For information about our operating revenues disaggregated by customer class for the years ended December 31, 2023, 2022, and 2021, see Note 1(d), Operating Revenues, and Note 4, Operating Revenues.

Natural Gas Sales Forecast

Our combined Wisconsin service territories experienced lower weather-normalized retail natural gas deliveries (excluding natural gas deliveries for electric generation) in 2023 as compared to 2022. We currently forecast retail natural gas delivery volumes to grow 0.8% in 2024, assuming normal weather.

Customers

	Year Ended December 31		
(in thousands)	**2023**	**2022**	**2021**
Customers – end of year			
Residential	**1,381.7**	1,365.5	1,353.2
Commercial and industrial	**134.8**	132.8	131.8
Transportation	**3.5**	3.5	3.5
Total customers	**1,520.0**	1,501.8	1,488.5

Natural Gas Supply, Pipeline Capacity and Storage

We manage portfolios of natural gas supply contracts, storage services, and pipeline transportation services designed to meet varying customer use patterns. For more information on our natural gas utility supply and transportation contracts, see Note 24, Commitments and Contingencies.

Pipeline Capacity and Storage

The interstate pipelines serving Wisconsin access supply from natural gas producing areas in the Southern and Eastern United States, along with western Canada. We have contracted for long-term firm capacity from a number of these sources. This strategy reflects management's belief that overall supply security is enhanced by geographic diversification of the supply portfolio.

Due to variations in natural gas usage in Wisconsin, our Wisconsin natural gas utilities have also contracted for substantial underground storage capacity, primarily in Michigan. WE, WPS, and WG have entered into long-term service agreements for approximately 99% of a wholly owned subsidiary of Bluewater's natural gas storage. Bluewater owns natural gas storage facilities in Michigan and provides approximately one-third of the current storage needs for our Wisconsin natural gas utilities. We target storage inventory levels at approximately 40% of forecasted demand for November through March. Diversity of natural gas supply enables us to manage significant changes in demand and to optimize our overall natural gas supply and capacity costs. We generally inject natural gas into storage during the spring and summer months and withdraw it in the winter months.

We hold daily transportation and storage capacity entitlements with interstate pipeline companies as well as other service providers under varied-length long-term contracts.

Natural gas pipeline capacity and storage and natural gas supplies under contract can be resold in secondary markets. Peak or near-peak demand generally occurs only a few times each year. The secondary markets facilitate utilization of capacity and supply during times when the contracted capacity and supply are in excess of utility demand. The proceeds from these transactions are passed through to customers, subject to our approved GCRMs. For information on the GCRMs, see Note 1(d), Operating Revenues.

To ensure a reliable supply of natural gas during peak winter conditions, we have LNG and propane facilities located within our distribution system. These facilities are typically utilized during extreme demand conditions to ensure reliable supply to our customers. WE recently finished construction of an LNG facility that was placed into service in November 2023, which provides approximately one Bcf of natural gas supply. In addition to its existing facilities, WG is constructing an additional LNG facility, which will provide approximately one Bcf of natural gas supply. Commercial operation of the WG LNG facility is targeted for 2024. The use of LNG allows us to meet anticipated peak demand without requiring the construction of additional interstate pipeline capacity.

Combined with our storage capability, management believes that the volume of natural gas under contract is sufficient to meet our forecasted firm peak-day and seasonal demand. Our Wisconsin segment natural gas utilities' forecasted design peak-day throughput is 36.7 million therms for the 2023 through 2024 heating season. Our Wisconsin segment natural gas utilities' peak daily send-out during 2023 was 22.9 million therms on January 31, 2023.

Natural Gas Supply

Our natural gas supply requirements are met through a combination of fixed-price purchases, index-priced purchases, storage, peak-shaving facilities, and natural gas supply call options. We contract for fixed-term firm natural gas supply each year to meet the demand of firm system sales customers. To supplement natural gas supply and manage risk, we purchase additional natural gas supply on the monthly and daily spot markets.

Hedging Natural Gas Supply Prices

As part of their hedging programs, our Wisconsin utilities further reduce their supply cost volatility through the use of a mix of financial instruments, such as NYMEX-based natural gas options and futures contracts. WE, WPS, and WG have PSCW approval to hedge up to 60% of planned winter demand and up to 15% of planned summer demand. These approvals allow these companies to pass 100% of the hedging costs (premiums, brokerage fees, and losses) and proceeds (gains) to customers through their respective GCRMs.

Illinois Segment

Our Illinois segment includes the natural gas utility operations of PGL and NSG. Our customers are located in Chicago and the northern suburbs of Chicago. PGL and NSG provide service to residential and commercial and industrial customers. In addition, PGL and NSG offer natural gas transportation services to our customers that elect to purchase natural gas directly from a third-party supplier. Major industries served include real estate, education, non-profits, wholesale distributors, and food manufacturing. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Illinois Segment Contribution to Net Income Attributed to Common Shareholders for information on natural gas sales volumes by customer class.

Operating Revenues

For information about our operating revenues disaggregated by customer class for the years ended December 31, 2023, 2022, and 2021, see Note 1(d), Operating Revenues, and Note 4, Operating Revenues.

Customers

	Year Ended December 31		
(in thousands)	**2023**	**2022**	**2021**
Customers – end of year			
Residential	**922.9**	910.9	904.5
Commercial and industrial	**71.3**	71.1	71.5
Transportation	**62.0**	66.4	68.3
Total customers	**1,056.2**	1,048.4	1,044.3

Natural Gas Supply, Pipeline Capacity, and Storage

We manage portfolios of natural gas supply contracts, storage services, and pipeline transportation services designed to meet varying customer use patterns. For more information on our natural gas utility supply and transportation contracts, see Note 24, Commitments and Contingencies.

Pipeline Capacity and Storage

The interstate pipelines serving Illinois access supply from natural gas producing areas in the Southern and Eastern United States, along with western Canada. We have contracted for long-term firm capacity from a number of these sources. This strategy reflects management's belief that overall supply security is enhanced by geographic diversification of the supply portfolio.

We own a 38.8 Bcf storage field (Manlove Field in central Illinois) and contract with various other underground storage service providers for additional storage services. Storage allows us to manage significant changes in daily natural gas demand and to purchase steady levels of natural gas on a year-round basis, which provides a hedge against supply cost volatility. We also own a natural gas pipeline system that connects Manlove Field to Chicago and nine major interstate pipelines. These assets are directed primarily to serving rate-regulated retail customers and are included in our regulatory rate base. We also use a portion of these company-owned storage and pipeline assets as a natural gas hub, which consists of providing transportation and storage services in interstate commerce to our wholesale customers. Customers deliver natural gas to us for storage through an injection into the storage reservoir, and we return the natural gas to the customers under an agreed schedule through a withdrawal from the storage reservoir. Title to the natural gas does not transfer to us. We recognize service fees associated with the natural gas hub services provided to wholesale customers. These service fees reduce the cost of natural gas and services charged to retail customers in rates.

Natural gas pipeline capacity and storage and natural gas supplies under contract can be resold in secondary markets. Peak or near-peak demand generally occurs only a few times each year. The secondary markets facilitate utilization of capacity and supply during times when the contracted capacity and supply are in excess of utility demand. The proceeds from these transactions are passed through to customers, subject to our approved GCRMs. For information on the GCRMs, see Note 1(d), Operating Revenues.

Combined with our storage capability, management believes that the volume of natural gas under contract is sufficient to meet our forecasted firm peak-day and seasonal demand. Our Illinois utilities' forecasted design peak-day throughput is 25.4 million therms for the 2023 through 2024 heating season. Our Illinois utilities' peak daily send-out during 2023 was 15.9 million therms on January 31, 2023.

Natural Gas Supply

Our natural gas supply requirements are met through a combination of fixed-price purchases, index-priced purchases, storage, peak-shaving facilities, and natural gas supply call options. We contract for fixed-term firm natural gas supply each year to meet the demand of firm system sales customers. To supplement natural gas supply and manage risk, we purchase additional natural gas supply on the monthly and daily spot markets.

Hedging Natural Gas Supply Prices

As part of their hedging programs, our Illinois utilities further reduce their supply cost volatility through the use of a mix of financial instruments, such as NYMEX-based natural gas options and futures contracts. Their hedging programs are reviewed by the ICC as part of the annual purchased gas adjustment reconciliation. They hedge between 25% and 50% of natural gas purchases, with a target of 37.5%.

Natural Gas System Modernization Program

During 2023, PGL continued work on the SMP, a project to replace approximately 2,000 miles of Chicago's aging natural gas pipeline infrastructure that began in 2011. Prior to December 1, 2023, PGL recovered these costs through a surcharge on customer bills pursuant to an ICC approved QIP rider. Beginning December 1, 2023, recovery of SMP costs are included in PGL's base rates. As part of the ICC's November 16, 2023 rate order issued in PGL's rate case, the ICC ordered PGL to pause spending on its SMP until the ICC has a proceeding to determine the optimal method of pipeline replacement and a prudent investment level. The ICC initiated the proceeding on January 31, 2024, and the proceeding is expected to last twelve months. PGL and NSG subsequently filed an application for rehearing with the ICC requesting reconsideration of various issues in the ICC's November 16, 2023 written orders.

On January 3, 2024, the ICC granted PGL and NSG a limited-scope rehearing, which includes the authorized spending for the completion of SMP projects that started in 2023 and the authorized spending for emergency repairs needed to ensure the safety and reliability of our delivery system.

For information on regulatory proceedings related to the SMP and future recovery of SMP costs, see Note 26, Regulatory Environment, and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity, and Capital Resources – Regulatory, Legislative, and Legal Matters – Future Illinois Proceedings.

Other States Segment

Our other states segment includes the natural gas utility operations of MERC and MGU and the non-utility operations of MERC related to servicing appliances for customers. MERC serves customers in various cities and communities throughout Minnesota, and MGU serves customers in southern and western Michigan. MERC and MGU provide service to residential and commercial and industrial customers. In addition, MERC and MGU offer natural gas transportation services to our customers that elect to purchase natural gas directly from a third-party supplier. Major industries served include education, wholesale distributors, real estate, non-profits, and restaurants. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Other States Segment Contribution to Net Income Attributed to Common Shareholders for information on natural gas sales volumes by customer class.

Operating Revenues

For information about our operating revenues disaggregated by customer class for the years ended December 31, 2023, 2022, and 2021, see Note 1(d), Operating Revenues, and Note 4, Operating Revenues.

Customers

	Year Ended December 31		
(in thousands)	**2023**	**2022**	**2021**
Customers – end of year			
Residential	**379.3**	375.4	370.1
Commercial and industrial	**36.8**	36.4	35.5
Transportation	**19.5**	19.7	23.6
Total customers	**435.6**	431.5	429.2

Natural Gas Supply, Pipeline Capacity and Storage

We manage portfolios of natural gas supply contracts, storage services, and pipeline transportation services designed to meet varying customer use patterns. For more information on our natural gas utility supply and transportation contracts, see Note 24, Commitments and Contingencies.

Pipeline Capacity and Storage

MGU owns a 2.9 Bcf storage field (Partello in Michigan) and contracts with various other underground storage service providers for additional storage services. We contract with local distribution companies and interstate pipelines to purchase firm transportation services. We believe that having diverse capacity and storage benefits our customers.

Natural gas pipeline capacity and storage and natural gas supplies under contract can be resold in secondary markets. Peak or near-peak demand generally occurs only a few times each year. The secondary markets facilitate utilization of capacity and supply during times when the contracted capacity and supply are in excess of utility demand. The proceeds from these transactions are passed through to customers, subject to our approved GCRMs. For information on the GCRMs, see Note 1(d), Operating Revenues.

Combined with our storage capability, management believes that the volume of gas under contract is sufficient to meet our forecasted firm peak-day and seasonal demand. Forecasted design peak-day throughput for our other states utilities is 9.7 million therms for the 2023 through 2024 heating season. Our other states utilities' peak daily send-out during 2023 was 6.8 million therms on February 3, 2023.

Natural Gas Supply

Our natural gas supply requirements are met through a combination of fixed-price purchases, index-priced purchases, contracted and owned storage, and natural gas supply call options. We contract for fixed-term firm natural gas supply each year to meet the demand of firm system sales customers. To supplement natural gas supply and manage risk, we purchase additional natural gas supply on the monthly and daily spot markets.

Hedging Natural Gas Supply Prices

Our other states utilities further reduce their supply cost volatility through the use of financial instruments, such as commodity futures, swaps, and options as part of their hedging programs. MERC has MPUC approval to hedge up to 30% of planned winter demand using NYMEX financial instruments. MGU has MPSC approval to hedge up to 20% of its planned annual purchases using NYMEX financial instruments.

General

Seasonality

Electric Utility Operations – Wisconsin Segment

Our electric utility sales are impacted by seasonal factors and varying weather conditions. We sell more electricity during the summer months because of the residential cooling load. We continue to upgrade our electric distribution system, including substations, transformers, and lines, to meet the demand of our customers. In 2023, our generating plants performed as expected during the warmest periods of the summer, and all power purchase commitments under firm contract were received. During this period, our electric utilities did not make any public appeals for conservation, and they did not interrupt or curtail service to non-firm customers who participate in load management programs. Our electric utilities did have economic interruption events; however, service to customers was not curtailed. Economic interruptions are declared during times in which the price of electricity in the regional market exceeds the cost of operating the company's peaking generation. During this time, customers taking service under these interruptible programs can choose to continue using electricity at a price based on wholesale market prices or to reduce their load.

Natural Gas Utility Operations – Wisconsin, Illinois, and Other States Segments

Since the majority of our customers use natural gas for heating, customer use is sensitive to weather and is generally higher during the winter months. Accordingly, we are subject to some variations in earnings and working capital throughout the year as a result of changes in weather. The effect on earnings from these changes in weather are reduced by decoupling mechanisms included in the rates of PGL, NSG, and MERC. These mechanisms differ by state and allow the utilities to recover or refund the differences between actual and authorized margins for certain customer classes.

Our natural gas utilities' working capital needs are met by cash generated from operations and debt (both long-term and short-term). The seasonality of natural gas revenues causes the timing of cash collections to be concentrated from January through June. A portion of the winter natural gas supply needs is typically purchased and stored from April through November. Also, planned capital spending on our natural gas distribution facilities is concentrated in April through November. Because of these timing differences, the cash flow from customers is typically supplemented with temporary increases in short-term borrowings (from external sources) during the late summer and fall. Short-term debt is typically reduced over the January through June period.

Competition

Electric Utility Operations – Wisconsin Segment

Our electric utilities face competition from various entities and other forms of energy sources available to customers, including self-generation by customers and alternative energy sources. Our electric utilities compete with other utilities for sales to municipalities and cooperatives as well as with other utilities and marketers for wholesale electric business.

Natural Gas Utility Operations – Wisconsin, Illinois, and Other States Segments

Our natural gas utilities also face varying degrees of competition from other entities and other forms of energy available to consumers. Many large commercial and industrial customers have the ability to switch between natural gas and alternative fuels. Electrification initiatives or mandates are being considered or proposed by local and state governments. In addition, the majority of our natural gas customers have the opportunity to choose a natural gas supplier other than us. Our natural gas utilities offer transportation services for customers that elect to purchase natural gas directly from a third-party supplier. We continue to earn distribution revenues from these transportation customers for their use of our distribution systems to transport natural gas to their facilities. As such, the loss of revenue associated with the cost of natural gas that our transportation customers purchase from third-party suppliers has little impact on our net income, as it is offset by an equal reduction to natural gas costs.

For more information on competition in each of our service territories, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity, and Capital Resources – Competitive Markets.

Environmental Goals

Natural Gas Utility Operations – Wisconsin, Illinois, and Other States Segments

We continue to reduce methane emissions by improving our natural gas distribution system. We set a target across our natural gas distribution operations to achieve net-zero methane emissions by the end of 2030. We plan to achieve our net-zero goal through an effort that includes both continuous operational improvements and equipment upgrades, as well as the use of RNG throughout our natural gas utility systems. In 2022, we received approval from the PSCW for our RNG pilots. We have since signed contracts for RNG for our natural gas distribution business in Wisconsin, which will be transporting the output of local dairy farms onto our gas distribution systems. The RNG supplied will directly replace higher-emission methane from natural gas that would have entered our pipes. These contracts bring us to 1.8 Bcf of RNG planned to enter our systems. RNG began flowing in 2023.

C. ELECTRIC TRANSMISSION SEGMENT

ATC is a regional transmission company that owns, maintains, monitors, and operates electric transmission systems in Wisconsin, Michigan, Illinois, and Minnesota. ATC is expected to provide comparable service to all customers, including WE, WPS, and UMERC, and to support effective competition in energy markets without favoring any market participant. ATC is regulated by the FERC for all rate terms and conditions of service and certain state regulatory commissions for routing and siting of transmission projects. ATC is also a transmission-owning member of MISO. MISO maintains operational control of ATC's transmission system, and WE, WPS, and UMERC are non-transmission owning members and customers of MISO. As of December 31, 2023, our ownership interest in ATC was approximately 60%. In addition, as of December 31, 2023, we owned approximately 75% of ATC Holdco, a separate entity formed in December 2016 to invest in transmission-related projects outside of ATC's traditional footprint. See Note 21, Investment in Transmission Affiliates, for more information.

The FERC and D.C. Circuit Court of Appeals have issued orders and an opinion, respectively, related to the authorized base ROE for all MISO transmission owners, including ATC. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity, and Capital Resources – Regulatory, Legislative, and Legal Matters – American Transmission Company Allowed Return on Equity Complaints for more information.

D. NON-UTILITY OPERATIONS

Non-Utility Energy Infrastructure Segment

The non-utility energy infrastructure segment includes We Power, which owns and leases generating facilities to WE; Bluewater, which owns underground natural gas storage facilities in Michigan; and WECI, which holds ownership interests in several renewable generating facilities. See Item 2. Properties, for more information on our non-utility energy infrastructure facilities.

W.E. Power, LLC

We Power, through wholly owned subsidiaries, designed and built approximately 2,500 MWs of generation in Wisconsin. This generation is made up of capacity from the two coal-fired ERGS units, ER 1 and ER 2, which were placed in service in February 2010 and January 2011, respectively, and the two natural gas-fired PWGS units, PWGS 1 and PWGS 2, which were placed in service in July 2005 and May 2008, respectively. Two unaffiliated entities collectively own approximately 17%, or approximately 211 MWs, of ER 1 and ER 2. We Power's share of the ERGS units and both PWGS units are being leased to WE under long-term leases (the ERGS units have 30-year leases that began on the in-service dates of the generating units and the PWGS units have 25-year leases that began on the in-service dates of the generating units).

Because of the significant investment necessary to construct these generating units, we constructed the plants under Wisconsin's Leased Generation Law, which allows a non-utility affiliate to construct an electric generating facility and lease it to the public utility. The law allows a public utility that has entered into a lease approved by the PSCW to recover fully in its retail electric rates that portion of any payments under the lease that the PSCW has allocated to the public utility's Wisconsin retail electric service, and all other costs that are prudently incurred in the public utility's operation and maintenance of the electric generating facility allocated to the utility's Wisconsin retail electric service. In addition, the PSCW may not modify or terminate a lease it has approved under the Leased Generation Law except as specifically provided in the lease or the PSCW's order approving the lease. This law effectively created regulatory certainty in light of the significant investment being made to construct the units. All four units were constructed under leases approved by the PSCW.

We are recovering our costs of these units, including subsequent capital additions, through lease payments that are billed from We Power to WE and then recovered in WE's rates as authorized by the PSCW and the FERC. Under the lease terms, our return is calculated using a 12.7% ROE and the equity ratio is assumed to be 55% for the ERGS units and 53% for the PWGS units.

Bluewater Natural Gas Holding, LLC

Bluewater, located in Michigan, primarily provides natural gas storage and hub services to our Wisconsin natural gas utilities. WE, WPS, and WG have entered into long-term service agreements for approximately one-third of their combined natural gas storage needs with a wholly owned subsidiary of Bluewater.

WEC Infrastructure LLC

At December 31, 2023, our non-utility energy infrastructure segment included WECI's ownership interests in the renewable generating facilities reflected in the table below.

Name	Ownership Interest	Commercial Operation
Bishop Hill III	90.0%	August 2018
Upstream	90.0%	January 2019
Coyote Ridge	80.0%	December 2019
Blooming Grove	90.0%	December 2020
Tatanka Ridge	85.0%	January 2021
Jayhawk	90.0%	December 2021
Thunderhead	90.0%	November 2022
Samson I [(1)]	80.0%	May 2022
Sapphire Sky	90.0%	February 2023

[1] Although Samson I was commercially operational in May 2022, WECI didn't complete the purchase of its initial 80% ownership interest in this solar facility until February 2023. WECI completed the acquisition of an additional 10% of Samson I in January 2024, bringing its ownership interest in Samson I to 90.0%. See Note 2, Acquisitions, for more information.

Bishop Hill III, Coyote Ridge, Blooming Grove, Tatanka Ridge, Jayhawk, Thunderhead, Samson I, and Sapphire Sky have offtake agreements with creditworthy counterparties for the sale of all of the energy they produce over periods ranging from 10 to 22 years following commercial operation. In addition, Upstream's revenue is substantially fixed over the 10-year period following commercial operation through an agreement with a creditworthy counterparty. Under the Tax Legislation, all of these investments qualify for PTCs. WECI is entitled to the tax benefits of Bishop Hill III, Upstream, Blooming Grove, Thunderhead, Samson I, and Sapphire Sky in proportion to its ownership interest. WECI is entitled to 99% of the tax benefits of Coyote Ridge and Tatanka Ridge for the first 11 years following commercial operation, and is entitled to 99% of the tax benefits of Jayhawk for the first 10 years following commercial operation, after which WECI will be entitled to any tax benefits equal to its ownership interests. WECI recognizes PTCs as power is generated over a period of 10 years following commercial operation. Under the new IRA transferability option, WEC Energy Group entered into a sales agreement in September 2023 to sell substantially all of the PTCs generated by the WECI generating facilities in 2023 to a third party. See Note 1(q), Income Taxes, for more information about the impact of these sales.

In October 2022, WECI signed an agreement to acquire an 80% ownership interest in Maple Flats, a 250 MW solar generating facility under construction in Clay County, Illinois. The project has an offtake agreement for all of the energy to be produced by the facility for a period of 15 years following commencement of commercial operation. WECI's investment in Maple Flats is expected to qualify for PTCs.

See Note 2, Acquisitions, for more information on certain of these renewable generating facilities.

Seasonality

The electricity produced and revenues generated by our wind generating facilities depend heavily on wind conditions, which are variable. Operating results for wind generating facilities vary significantly from period to period depending on the wind conditions during the periods in question. Historically, wind production has been greater in the first and fourth quarters.

The electricity produced and revenues generated by our Samson I solar generating facility is also variable and depends heavily on seasonality and weather conditions. Spring and summer are usually the peak solar production seasons due to increased direct sunlight and longer days. With regards to weather, solar panels will still work on cloudy and rainy days, but solar system output will be lower than on clear, sunny days. Also, major storms can damage solar panels and other equipment and lead to lower power generation until equipment can be repaired or replaced and brought back online. See Note 7, Property, Plant, and Equipment, for more information on the wind storms that damaged equipment at Samson I in 2023.

Corporate and Other Segment

The corporate and other segment includes the operations of the WEC Energy Group holding company, the Integrys holding company, and the PELLC holding company, as well as the operations of Wispark and WBS. Wispark develops and invests in real estate, primarily in southeastern Wisconsin. WBS is a wholly owned centralized service company that provides administrative and general support services to our regulated entities. WBS also provides certain administrative and support services to our nonregulated entities. This segment also includes Wisvest, WECC, and PDL which no longer have significant operations.

E. REGULATION

We are a holding company and are subject to the requirements of the PUHCA 2005. We also have various subsidiaries that meet the definition of a holding company under the PUHCA 2005 and are also subject to its requirements.

Pursuant to the non-utility asset cap provisions of Wisconsin's public utility holding company law, the sum of certain assets of all non-utility affiliates in a holding company system generally may not exceed 25% of the assets of all public utility affiliates. However, among other items, the law exempts energy-related assets, including the generating plants constructed by We Power and the other assets in our non-utility energy infrastructure segment, from being counted against the asset cap provided that they are employed in qualifying businesses. We report to the PSCW annually on our compliance with this law and provide supporting documentation to show that our non-utility assets are below the non-utility asset cap.

Regulated Utility Operations

In addition to the specific regulations noted above and below, our utilities are subject to various other regulations, which primarily consist of regulations, where applicable, of the EPA; the WDNR; the Illinois Department of Natural Resources; the Illinois Environmental Protection Agency; the Michigan Department of Environment, Great Lakes, and Energy; the Michigan Department of Natural Resources; the Army Corps; the Minnesota Department of Natural Resources; and the Minnesota Pollution Control Agency.

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Rates

Our utilities' rates are subject to the regulations and oversight of various state regulatory commissions and the FERC, as applicable. Decisions by these regulators can significantly impact our liquidity, financial condition, and results of operations. The following table compares our utility operating revenues by regulatory jurisdiction for each of the three years ended December 31:

	2023		2022		2021	
(in millions)	**Amount**	**Percent**	**Amount**	**Percent**	**Amount**	**Percent**
Electric						
Wisconsin	**$ 4,548.8**	**90.8 %**	$ 4,360.9	87.7 %	$ 4,035.1	88.9 %
Michigan	**141.4**	**2.8 %**	185.9	3.7 %	166.7	3.7 %
FERC – Wholesale	**320.6**	**6.4 %**	425.0	8.6 %	336.8	7.4 %
Total electric	**5,010.8**	**100.0 %**	4,971.8	100.0 %	4,538.6	100.0 %
Natural Gas						
Wisconsin	**1,610.5**	**43.6 %**	1,983.0	44.1 %	1,493.8	40.5 %
Illinois	**1,557.8**	**42.2 %**	1,890.9	42.0 %	1,672.8	45.3 %
Minnesota	**348.4**	**9.4 %**	400.7	8.9 %	367.1	10.0 %
Michigan	**175.3**	**4.8 %**	223.5	5.0 %	156.5	4.2 %
Total natural gas	**3,692.0**	**100.0 %**	4,498.1	100.0 %	3,690.2	100.0 %
Total utility operating revenues	**$ 8,702.8**		$ 9,469.9		$ 8,228.8	

Retail Rates

The state regulatory commissions have general supervisory and regulatory powers over public utilities in their respective jurisdictions including, but not limited to, approval of retail utility rates and standards of service, mergers, affiliate transactions, location and construction of electric generating units and natural gas facilities, and certain other additions and extensions to utility facilities. The PSCW, ICC, and MPUC also regulate security issuances at utilities in their respective jurisdictions. In addition, the FERC regulates security issuances for UMERC.

Historically, retail rates approved by the state commissions have been designed to provide utilities the opportunity to generate revenues to recover all prudently-incurred costs, along with a return on investment sufficient to pay interest on debt and provide a reasonable ROE. Rates charged to customers vary according to customer class and rate jurisdiction. WE, WPS, and WG are each subject to an earnings sharing mechanism in which a portion of the utility's earnings are required to be refunded to customers if the utility earns above its authorized ROE. See Note 26, Regulatory Environment, for more information on these earnings sharing mechanisms.

The table below reflects the various state commissions that regulated each of our utilities' retail rates during 2023, along with the approved ROE and capital structure for each utility during 2023.

Regulated Retail Rates	Regulatory Commission	Authorized ROE	Average Common Equity Component
WE – Electric, natural gas, and steam	PSCW	9.80%	53.0%
WPS – Electric and natural gas	PSCW	9.80%	53.0%
WG – Natural gas	PSCW	9.80%	53.0%
UMERC – Electric (former WE customers)	MPSC	10.1%	55.3%
UMERC – Electric (former WPS customers)	MPSC	10.2%	52.94%
PGL – Natural gas [1]	ICC	9.05% / 9.38%	50.33% / 50.79%
NSG – Natural gas [2]	ICC	9.67%	51.58%
MERC – Natural gas [3]	MPUC	9.7%	50.9%
MGU – Natural gas [4]	MPSC	9.85%	51.5%

[1] In accordance with its most recent rate order, effective December 1, 2023, PGL's base rates reflect a 9.38% authorized ROE and an average common equity component of 50.79%. See Note 26, Regulatory Environment, for more information.

[2] In accordance with its most recent rate order, effective February 1, 2024, NSG's new base rates reflect a 9.38% authorized ROE and an average common equity component of 52.58%. See Note 26, Regulatory Environment, for more information.

(3) In accordance with its most recent rate order, effective March 1, 2024, MERC's base rates will reflect a 9.65% authorized ROE and an average common equity component of 53.0%. See Note 26, Regulatory Environment, for more information.

(4) In accordance with its most recent rate order, effective January 1, 2024, MGU's base rates reflect a 9.80% authorized ROE and an average common equity component of 51.0%. See Note 26, Regulatory Environment, for more information.

In addition to amounts collected from customers through approved base rates, our utilities have certain recovery mechanisms in place that allow them to recover or refund prudently incurred costs that differ from those approved in base rates.

Embedded within our electric utilities' rates is an amount to recover fuel and purchased power costs. The Wisconsin retail fuel rules require a utility to defer, for subsequent rate recovery or refund, any under-collection or over-collection of fuel and purchased power costs that are outside of the utility's symmetrical fuel cost tolerance, which the PSCW typically sets at plus or minus 2% of the utility's approved fuel and purchased power cost plan. The deferred fuel and purchased power costs are subject to an excess revenues test. If the utility's ROE in a given year exceeds the ROE authorized by the PSCW, the recovery of under-collected fuel and purchased power costs would be reduced by the amount by which the utility's return exceeds the authorized amount. Prudently incurred fuel and purchased power costs are recovered dollar-for-dollar from our Michigan retail electric customers.

Our natural gas utilities operate under GCRMs as approved by their respective state regulator. Generally, the GCRMs allow for a dollar-for-dollar recovery of prudently incurred natural gas costs.

See Note 1(d), Operating Revenues, for additional information on the significant mechanisms our utilities had in place during 2023 that allowed them to recover or refund changes in prudently incurred costs from rate case-approved amounts.

Our utilities file periodic requests with their respective state commission for changes in retail rates. All of our utilities' rate requests are based on forward looking test years, which reflect additions to infrastructure and changes in costs incurred or expected to be incurred. For information on our regulatory proceedings, see Note 26, Regulatory Environment. Orders from our respective regulators can be viewed at the following websites:

Regulatory Commission	**Website**
PSCW	https://psc.wi.gov/
ICC	https://www.icc.illinois.gov/
MPSC	http://www.michigan.gov/mpsc/
MPUC	http://mn.gov/puc/

The material and information contained on these websites are not intended to be a part of, nor are they incorporated by reference into, this Annual Report on Form 10-K.

Wholesale Rates

The FERC regulates our wholesale sales of electric energy, capacity, and ancillary services. Our electric utilities have received market-based rate authority from the FERC. Market-based rate authority allows wholesale electric sales to be made in the MISO market and directly to third parties based on the negotiated market value of the transaction. WE and WPS also make wholesale sales pursuant to cost-based formula rates. Cost-based formula rates provide for recovery of the utility's costs and an approved rate of return. The predetermined formula is initially based on the utility's expenses from the previous year, but is eventually trued up to reflect actual, current-year costs.

Electric Transmission, Capacity, and Energy Markets

In connection with its status as a FERC-approved RTO, MISO operates an energy and ancillary services market and manages the flow of high-voltage electricity across the transmission system in its region. MISO is responsible for monitoring and ensuring equal access to the electric transmission system in its footprint.

In MISO, transmission costs are allocated in accordance with the MISO tariff, which is reviewed and approved by the FERC. Base transmission costs are paid by load-serving entities located in the service territories of each MISO transmission owner. Costs for new regional transmission projects are allocated to load-serving entities throughout the MISO footprint, while the costs for new generation interconnections are allocated to the interconnection customer.

Within MISO, transmission congestion is monetized and included within an LMP that is established through the energy market. The LMP system includes the ability to hedge transmission congestion costs through ARRs and FTRs. ARRs are allocated to market participants by MISO, and FTRs are purchased through auctions. A new allocation and auction was completed for the period of June 1, 2023, through May 31, 2024. The resulting ARR allocation and the secured FTRs are expected to mitigate our transmission congestion risk for that period.

MISO has seasonal zonal resource adequacy requirements to ensure there is sufficient generation capacity to serve load within each zone and the MISO footprint. To meet this requirement, load-serving entities can own generation and demand response resources, acquire generation capacity through MISO's annual capacity auction, or acquire generation capacity through bilateral contracts. The zone in which our electric utilities’ load resides, along with the MISO North region as a whole, had sufficient generation capacity resources to meet their respective planning reserve margins for the period between June 1, 2023 and May 31, 2024.

We manage our electric generation portfolios to minimize their exposure within MISO’s annual capacity auction. This includes managing the retirement of existing generation resources and the addition of new generation resources to maintain a diversified portfolio to ensure we do not have a significant short position.

Other Electric Regulations

Our electric utilities are subject to the Federal Power Act and the corresponding regulations developed by certain federal agencies. Among other things, the Federal Power Act makes electric utility industry consolidation more feasible and authorizes the FERC to review proposed mergers and the acquisition of generation facilities. The FERC also oversees the Electric Reliability Organization, which establishes mandatory electric reliability standards and has the authority to levy monetary sanctions for failure to comply with these standards.

WE and WPS are subject to Act 141 in Wisconsin, and UMERC is subject to Public Acts 295 and 342 in Michigan, which contain certain minimum requirements for renewable energy generation.

Other Natural Gas Regulations

Almost all of the natural gas we distribute is transported to our distribution systems by interstate pipelines. The pipelines' transportation and storage services, including PGL's natural gas hub, are regulated by the FERC under the Natural Gas Act and the Natural Gas Policy Act of 1978. In addition, the PHMSA and the state commissions are responsible for monitoring and enforcing requirements governing our natural gas utilities' safety compliance programs for our pipelines under the United States Department of Transportation regulations. These regulations include 49 CFR Part 191 (Transportation of Natural and Other Gas by Pipeline; Annual Reports, Incident Reports, and Safety-Related Condition Reports), 49 CFR Part 192 (Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards), and 49 CFR Part 195 (Transportation of Hazardous Liquids by Pipeline).

We also continue to monitor the progress of the PHMSA’s proposed rulemaking titled "Gas Pipeline Leak Detection and Repair," which could have a significant impact on our natural gas utilities. A final rule is expected to be released in 2024.

We are required to provide natural gas service and grant credit (with applicable deposit requirements) to customers within our service territories. We are generally not allowed to discontinue natural gas service during winter moratorium months to residential heating customers who do not pay their bills. Federal and certain state governments have programs that provide for a limited amount of funding for assistance to low-income customers of our utilities.

Non-Utility Energy Infrastructure Operations

The generation facilities constructed by wholly owned subsidiaries of We Power are being leased on a long-term basis to WE. Environmental permits necessary for operating the facilities are the responsibility of the operating entity, WE. We Power received determinations from the FERC that upon the transfer of the facilities by lease to WE, We Power's subsidiaries would not be deemed public utilities under the Federal Power Act and thus would not be subject to the FERC's jurisdiction.

Bluewater is regulated by the FERC under the Natural Gas Act and the Natural Gas Policy Act of 1978. In addition, the Pipeline and Hazardous Materials Safety Administration is responsible for monitoring and enforcing requirements governing Bluewater's safety compliance programs for its pipelines under the United States Department of Transportation regulations. These regulations include 49 CFR Parts 191, 192, and 195. Given that Bluewater is required to route some of its natural gas through Canada, applicable reporting and licensing with the United States Department of Energy and the Canadian National Energy Board are also required, along with routine reporting related to imports and exports.

All of our operational renewable generating facilities in our non-utility energy infrastructure segment are also subject to the FERC's regulation of wholesale energy under the Federal Power Act.

Compliance Costs

The regulations and oversight described above significantly influence our operating environment, and may cause us to incur compliance and other related costs and may affect our ability to recover these costs from our utility customers. Any anticipated capital expenditures for compliance with government regulations for the next three years are included in the estimated capital expenditures described in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Cash Requirements.

F. ENVIRONMENTAL COMPLIANCE

Our operations, especially as they relate to our coal-fired generating facilities, are subject to extensive environmental regulation by state and federal environmental agencies governing air and water quality, hazardous and solid waste management, environmental remediation, and management of natural resources. Costs associated with complying with these requirements are significant. Additional future environmental regulations or revisions to existing laws, including for example, additional regulation related to GHG emissions, coal combustion products, air emissions, water use, or wastewater discharges and other climate change issues, could significantly increase these environmental compliance costs.

Anticipated expenditures for environmental compliance and certain remediation issues for the next three years are included in the estimated capital expenditures described in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Cash Requirements. For a discussion of certain environmental matters affecting us, including rules and regulations relating to air quality, water quality, land quality, and climate change, see Note 24, Commitments and Contingencies.

G. HUMAN CAPITAL

We believe our employees are among our most important resources, so investing in human capital is critical to our success. We strive to foster a diverse workforce and inclusive workplace; attract, retain and develop talented personnel; and keep our employees safe and healthy.

Our Board of Directors retains collective responsibility for comprehensive risk oversight, including critical areas that could impact our sustainability, such as human capital. Management regularly reports to the Board of Directors on human capital management topics, including corporate culture, diversity, equity, and inclusion, employee development, and safety and health. The Board of Directors delegates specified duties to its committees. In addition to its responsibilities relative to executive compensation, the Compensation Committee has oversight responsibility for reviewing organizational matters that could significantly impact us, including succession planning. The Compensation Committee reviews recruiting and development programs and priorities, receives updates on key talent, and assesses workforce diversity across the organization.

Workforce

As of December 31, 2023, we had the following number of employees, including those represented under union agreements:

	Total Employees	Union Employees
WE	2,533	1,955
WPS	1,154	832
WG	378	260
PGL	1,221	830
NSG	154	119
MERC	197	41
MGU	141	91
WBS	1,222	—
Total employees	7,000	4,128

We have a local union presence that spans Wisconsin, Illinois, Minnesota, and Michigan. We believe we have very good overall relations with our workforce.

In order to attract and retain talent, we provide competitive wages and benefits to our employees based on their performance, role, location, and market data. Our compensation package also includes a 401(k) savings plan with an employer match, an annual incentive plan based on meeting company goals, healthcare and insurance benefits, vacation and paid time off days, as well as other benefits.

Diversity, Equity, and Inclusion

We are committed to fostering a diverse workforce and inclusive workplace. Our commitment is a core strategic competency and an integral part of our culture. As of December 31, 2023, women and racial minorities represented approximately 25% and 26%, respectively, of our workforce. We have a number of initiatives that promote diverse workforce contributions, educate employees about diversity, equity, and inclusion, and ensure our companies are attractive employers for persons of diverse backgrounds. These initiatives include nine business resource groups (voluntary, employee-led groups organized around a particular shared background or interest), mentoring programs, and training for leaders on countering unconscious bias, building inclusive teams, and preventing workplace harassment. We also support external leadership and educational programs that support, train, and promote women and minorities in the communities we serve.

Safety and Health

Our Executive Safety Committee directs our safety and health strategy, works to ensure consistency across groups, and reinforces our ongoing safety commitment that we refer to as “Target Zero.” Under our Target Zero commitment, we have an ultimate goal of zero incidents, accidents, and injuries. Our corporate safety program provides a forum for addressing employee concerns, training employees and contractors on current safety standards, and recognizing those who demonstrate a safety focus. We monitor and set goals for days away, restricted or transferred metrics, and measurable leading indicators, which together raise awareness about employee safety and guide injury-prevention activities.

We also provide employees various benefits and resources designed to promote healthy living, both at work and at home. We encourage employees to receive preventive examinations and to proactively care for their health through free health screenings, wellness challenges, and other resources.

Development and Training

Employee training and development of both technical and leadership skills are integral aspects of our human capital strategy. We provide employees with a wide range of development opportunities, including online training, simulations, live classes, and mentoring to assist with their career advancement. These programs include safety and technical job skill training as well as soft-skill programs focused on relevant subjects, including communication and change management. Development of leadership skills remains a top priority and is specialized for all levels of employees. We have specific leadership programs for aspiring leaders and new supervisors, managers, and directors. This development of our employees is an integral part of our succession planning and provides continuity for our senior leadership.

ITEM 1A. RISK FACTORS

We are subject to a variety of risks, many of which are beyond our control, that may adversely affect our business, financial condition, and results of operations. You should carefully consider the following risk factors, as well as the other information included in this report and other documents filed by us with the SEC from time to time, when making an investment decision.

Risks Related to Legislation and Regulation

Our business is significantly impacted by governmental regulation and oversight.

We are subject to significant state, local, and federal governmental regulations, including regulations by the various utility commissions in the states where we serve customers. These regulations significantly influence our operating environment, may affect our ability to recover costs from utility customers, affect our ability to implement our corporate strategy, and cause us to incur substantial compliance and other costs. Changes in regulations, interpretations of regulations, or the imposition of new regulations could also significantly impact us, including requiring us to change our business operations. Many aspects of our operations are regulated and impacted by government regulation, including, but not limited to: the rates we charge our retail electric, natural gas, and steam customers; the authorized rates of return of our utilities; construction and operation of electric generating facilities and electric and natural gas distribution systems, including the ability to recover such costs; decommissioning generating facilities, the ability to recover the related costs, and continuing to recover the return on the net book value of these facilities; wholesale power service practices; electric reliability requirements and accounting; participation in the interstate natural gas pipeline capacity market; standards of service; issuance of securities; short-term debt obligations; transactions with affiliates; and billing practices. Failure to comply with any applicable rules or regulations may lead to customer refunds, penalties, and other payments, which could materially and adversely affect our results of operations and financial condition.

The rates, including adjustments determined under riders, we are allowed to charge our customers for retail and wholesale services have the most significant impact on our financial condition, results of operations, and liquidity. Rate regulation provides us an opportunity to recover prudently incurred costs and earn a reasonable rate of return on invested capital. However, our ability to obtain rate adjustments in the future is dependent upon regulatory action, the outcome of which can be influenced by the level of opposition by intervening parties; potential rate impacts; increasing levels of regulatory review; and changes in the political, regulatory, or legislative environments. There is no assurance that our regulators will consider all of our costs to have been prudently incurred. In addition, our rate proceedings may not always result in rates that fully recover our costs or provide for a reasonable ROE. We defer certain costs and revenues as regulatory assets and liabilities for future recovery from or refund to customers, as authorized by our regulators. Future recovery of regulatory assets is not assured and is subject to review and approval by our regulators. If recovery of regulatory assets is not approved or is no longer deemed probable, these costs would be recognized in current period expense and could have a material adverse impact on our results of operations, cash flows, and financial condition.

Changes in the local and national political, regulatory, and economic environment have had, and may in the future have, an adverse effect on regulatory decisions, which could impair the ability of our utility subsidiaries to recover costs historically collected from customers. These decisions, which may come from any level of government, may cause us to cancel or delay current or planned projects, to reduce or delay other planned capital expenditures, or to pay for investments or otherwise incur costs that our utilities may not be able to recover through rates or otherwise. In November 2023, the ICC issued final rate orders for PGL and NSG, with PGL rates effective December 1, 2023. In the rate order, the ICC disallowed certain previously incurred capital costs in Illinois, which resulted in PGL and NSG recording an impairment loss in the fourth quarter of 2023. In addition, the ICC paused spending on PGL's SMP for at least one year, causing uncertainty of recovery of costs for existing and future projects. Due to the expiration of the QIP rider in December 2023, PGL had included the costs of necessary infrastructure improvements related to the SMP in its rate case. In January 2024, the ICC granted a rehearing to PGL and NSG with a limited scope. Disallowance of PGL's and NSG's capital costs will not be part of the rehearing. Subsequent to the rehearing, we anticipate appealing the ICC's disallowance of these capital costs to the Illinois Circuit Court, which may result in extended uncertainty related to the recovery of existing and future investments in capital expenditures and our natural gas infrastructure in Illinois, and may impact future capital plans.

Prior to its expiration, the QIP rider provided PGL with recovery of, and a return on, qualifying natural gas infrastructure investments that are placed in service between regulatory rate reviews. This rider continues to be subject to an annual reconciliation whereby costs are reviewed for accuracy and prudency. There can be no assurance that all costs incurred under the QIP rider during the open reconciliation years, which include 2016 through 2023, will be deemed recoverable by the ICC. Regulatory lag, as well as the risk of costs being deemed unrecoverable during the review of the outstanding reconciliations, could have a material adverse impact on PGL’s, and correspondingly our, results of operations, financial position, and liquidity.

We believe we have obtained the necessary permits, approvals, authorizations, certificates, and licenses for our existing operations, have complied in all material respects with all of their associated terms, and that our businesses are conducted in accordance with applicable laws. These permits, approvals, authorizations, certificates, and licenses may be revoked or modified by the agencies that granted them if facts develop that differ significantly from the facts assumed when they were issued. In addition, permits and other approvals and licenses are often granted for a term that is less than the expected life of the associated facility. Licenses and permits may require periodic renewal, which may result in additional requirements being imposed by the granting agency. In addition, existing regulations may be revised or reinterpreted by federal, state, and local agencies, or these agencies may adopt new laws and regulations that apply to us. We cannot predict the impact on our business and operating results of any such actions by these agencies.

If we are unable to recover costs of complying with regulations or other associated costs in customer rates in a timely manner, or if we are unable to obtain, renew, or comply with these governmental permits, approvals, authorizations, certificates, or licenses, our results of operations and financial condition could be materially and adversely affected.

We face significant costs to comply with existing and future environmental laws and regulations.

Our operations are subject to extensive and evolving federal, state, and local environmental laws, regulations, and permit requirements related to, among other things, air emissions (including, but not limited to: CO_2, methane, mercury, SO_2, and NOx), protection of natural resources, water quality, wastewater discharges, and management of hazardous and toxic substances and solid wastes and soils. The EPA has recently adopted and implemented (or is in the process of implementing) new environmental regulations, with more in the proposal process. These include regulations that govern the emission of NOx, ozone, fine particulates, and other air pollutants under the CAA through the NAAQS, climate change, NSPS for GHG emissions from new, modified, and reconstructed fossil-fueled power plants, other air quality regulations, and water quality regulations. For example, the EPA finalized regulations under the CWA that govern cooling water intake structures at our power plants, revised again the effluent guidelines for steam electric generating plants, and along with the Army Corps, released a final rule revising the definition of WOTUS that may impact projects requiring federal permits. Several of these rules were challenged or reviewed by agencies under the Biden Administration's Executive Order 13990, which creates additional uncertainty. As a result of these challenges and reviews, existing environmental laws and regulations may be revised or new laws or regulations may be adopted at the federal, state, or local level.

We incur significant capital and operating resources to comply with environmental laws, regulations, and requirements, including costs associated with the installation of pollution control equipment; operating restrictions on our facilities; and environmental monitoring, emissions fees, and permits at our facilities. The operation of emission control equipment and compliance with rules regulating our intake and discharge of water could also increase our operating costs and reduce the generating capacity of our power plants. These regulations may create substantial additional costs in the form of taxes or emission allowances and could affect the availability and/or cost of fossil fuels and our ability to continue operating certain generating units. Failure to comply with these laws, regulations, and requirements, even if caused by factors beyond our control, may result in the assessment of civil or criminal penalties and fines. We continue to assess the potential cost of complying, and to explore different alternatives in order to comply, with these and other environmental regulations.

As a result of these compliance costs and other factors, certain of our coal-fired electric generating facilities have become uneconomical to maintain and operate, which has resulted in these units being retired or converted to an alternative type of fuel. As part of our commitment to a cleaner energy future, we have already retired more than 1,900 MWs of coal-fired generation since the beginning of 2018. We expect to retire approximately 1,800 MWs of additional fossil-fueled generation by the end of 2031, and plan to replace a portion of the retired capacity by building and owning zero-carbon-emitting renewable generation facilities. We continue to evaluate the conversion of certain coal units to natural gas.

Our electric and natural gas utilities are also subject to significant liabilities related to the investigation and remediation of environmental impacts at certain of our current and former facilities and at third-party owned sites. We accrue liabilities and defer costs (recorded as regulatory assets) incurred in connection with our former manufactured gas plant sites. These costs include all costs incurred to date that we expect to recover, management's best estimates of future costs for investigation and remediation and related legal expenses, and are net of amounts recovered (or that may be recovered) from insurance or other third parties. Due to the potential for the imposition of stricter standards and greater regulation in the future, the possibility that other potentially responsible parties may not be willing or financially able to contribute to cleanup costs, a change in conditions or the discovery of additional contamination, our remediation costs could increase, and the timing of our capital and/or operating expenditures in the future may accelerate or could vary from the amounts currently accrued.

Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental laws and regulations, occurs frequently throughout the United States. This litigation has included claims for damages alleged to have been caused by GHG and other emissions and exposure to regulated substances and/or requests for injunctive relief in connection with such matters. In addition to claims relating to our current facilities, we may also be subject to potential liability in connection with the environmental condition of facilities that we previously owned and operated, regardless of whether the liabilities arose before, during, or after the time we owned or operated these facilities. If we fail to comply with environmental laws and regulations or cause (or caused) harm to the environment or persons, that failure or harm may result in the assessment of civil penalties and damages against us. The incurrence of a material environmental liability or a material judgment in any action for personal injury or property damage related to environmental matters could have a material adverse effect on our results of operations and financial condition.

In the event we are not able to recover all of our environmental expenditures and related costs from our customers in the future, our results of operations and financial condition could be adversely affected. Further, increased costs recovered through rates could contribute to reduced demand for electricity and natural gas, which could adversely affect our results of operations, cash flows, and financial condition.

Our operations, capital expenditures, and financial results may be affected by the impact of greenhouse gas legislation, regulation, and emission reduction goals.

There is significant attention to issues concerning climate change. Management expects this attention to continue since climate change is one of President Biden's primary initiatives, with significant actions being taken by his administration. As a result, we expect the EPA and states to finalize and implement additional regulations to restrict emissions of GHGs. There have also been increasing efforts to introduce and adopt electrification initiatives and/or mandates and other efforts to reduce or eliminate reliance on natural gas as an energy source. In addition, there is increasing activism from other stakeholders, including institutional investors and other sources of financing, to accelerate the transition to lower GHG emissions.

Costs associated with such legislation, regulation, and emission reduction goals could be significant within our electric and natural gas operations. GHG regulations that may be finalized in the future, at either the federal or state level, may cause our environmental compliance spending to differ materially from the amounts currently estimated. There is no guarantee that we will be allowed to fully recover costs incurred to comply with these and other federal and state regulations or that cost recovery will not be delayed or otherwise conditioned. These regulations, as well as changes in the fuel markets and advances in technology, could make additional electric generating units uneconomic to maintain or operate, may impact how we operate our existing fossil-fueled power plants and biomass facility, and could cause us to retire and replace units earlier than planned under the ESG Progress Plan, which could lead to a possible loss on abandonment and reduced revenues. In addition, our natural gas delivery systems and natural gas storage fields may generate fugitive gas as a result of normal operations and as a result of excavation, construction, and repair. Fugitive gas typically vents to the atmosphere and consists primarily of methane. CO_2 is also a byproduct of natural gas consumption.

In a movement toward electrification, certain states and municipalities near or in our service territories have passed legislation or are considering ordinances banning natural gas used in new construction in order to limit GHG emissions. For example, the city of Chicago is considering an ordinance that would ban the use of natural gas in most new buildings, and the ICC is exploring the role of natural gas in the future and issues related to decarbonization of the natural gas distribution system in Illinois. There have also been efforts to restrict residential natural gas-fired appliances. Future local, statewide, or nationwide actions like these to regulate GHG emissions could increase the price of natural gas, reduce the demand for natural gas, cause us to accelerate the replacement and/or updating of our natural gas delivery systems, and adversely affect our ability to operate our natural gas facilities. A significant increase in the price of natural gas may increase rates for our natural gas customers, which could also reduce natural gas demand and revenues. The adoption of electrification initiatives and/or mandates could also result in an increase in electrical demand and increased investment costs for existing or new electrical systems. These types of initiatives and/or mandates could result in increased costs associated with permitting and siting of new technologies and delayed installation and start-up timelines. In addition, financial investments in older carbon intensive technologies may not be fully realized.

We have set goals to achieve reductions in carbon emissions from our electric generation fleet by 60% by the end of 2025 and by 80% by the end of 2030, both from a 2005 baseline. Over the longer term, the target for our generation fleet is to be net carbon neutral by 2050. We also believe we will be in a position to eliminate coal as an energy source by the end of 2032.

We continue to monitor the financial and operational feasibility of taking more aggressive action to further reduce GHG emissions in order to limit future global temperature increases. We continue to reduce methane emissions by improving our natural gas distribution systems. We set a target across our natural gas distribution operations to achieve net-zero methane emissions by the end of 2030.

The ability to achieve these reductions in CO_2 and methane emissions depends on many external factors, including the ability to make operating refinements, the retirement of less efficient generating units, the development of relevant energy technologies, the use of RNG throughout our natural gas utility systems, and the ability to execute our capital plan. These efforts could impact how we operate our electric generating units and natural gas facilities and lead to increased competition and regulation, all of which could have a material adverse effect on our operations and financial condition.

Changes in tax legislation, IRS audits, or our inability to use certain tax benefits and carryforwards, may adversely affect our financial condition, results of operations, and cash flows, as well as our credit ratings.

Tax legislation and regulations can adversely affect, among other things, our financial condition, results of operations, cash flows, liquidity, and credit ratings. Future changes to corporate tax rates or policies, including under Treasury Regulations and guidance issued in connection with the IRA, could require us to take material charges against earnings. Such changes include, among other things, increasing the federal corporate income tax rate, disallowing or limiting the use of certain tax benefits and carryforwards, limiting interest deductions, and altering the expensing of capital expenditures. Our inability to manage these changes, an adverse determination by one of the applicable taxing jurisdictions, or additional interpretations, implementing regulations, amendments, or technical corrections by the Treasury Department, the IRS, or state income tax authorities, could significantly impact our financial results and cash flows.

We have significantly reduced our consolidated federal and state income tax liabilities in the past through tax credits, net operating losses, and charitable contribution deductions. A reduction in or disallowance of these tax benefits could adversely affect our earnings and cash flows. We have not fully used these allowed tax benefits in our previous tax filings and have carried them forward to use against future taxable income. Our inability to generate sufficient taxable income in the future to fully use these tax carryforwards before they expire, or to transfer future tax credits as discussed below, could significantly affect our tax obligations and financial results.

In addition, we have invested, and plan to continue to invest, in renewable energy generating facilities. These facilities generate PTCs or ITCs that we can use to reduce our federal tax obligations. Under the IRA, a transferability option also allows us to sell these tax credits to third parties. This is a new market that may require additional regulations and guidance from taxing authorities. The amount of tax credits we earn depends on available government incentives and policies, the amount of electricity produced, the applicable tax credit rate, or the amount of the investment in qualifying property. In addition, a variety of operating and economic factors, including transmission constraints, adverse weather conditions, and breakdown or failure of equipment, could significantly reduce the PTCs generated by the renewable projects we have invested in, resulting in a material adverse impact on our financial condition and results of operations. The imposition of additional taxes, tariffs, or other assessments related to renewable energy projects or the equipment necessary to generate or deliver it, as well as any reductions or eliminations of tax credits or other governmental incentives that promote renewable energy generating facilities, may limit our ability to make further investments in renewable energy generating facilities or reduce the returns on our existing investments.

We are also uncertain as to how credit rating agencies, capital markets, the FERC, or state public utility commissions will treat any future changes to federal or state tax legislation. These impacts could subject us to credit rating downgrades. In addition, certain financial metrics used by credit rating agencies, such as our funds from operations-to-debt percentage, could be negatively impacted by changes in federal or state income tax legislation.

Our electric utilities could be subject to higher costs and penalties as a result of mandatory reliability standards.

Our electric utilities are subject to mandatory reliability and critical infrastructure protection standards established by the North American Electric Reliability Corporation and enforced by the FERC. The critical infrastructure protection standards focus on controlling access to critical physical and cybersecurity assets. Compliance with the mandatory reliability standards could subject our electric utilities to higher operating costs. If our electric utilities are found to be in noncompliance with the mandatory reliability standards, they could be subject to sanctions, including substantial monetary penalties, or damage to our reputation.

Provisions of the Wisconsin Utility Holding Company Act limit our ability to invest in non-utility businesses and could deter takeover attempts by a potential purchaser of our common stock that would be willing to pay a premium for our common stock.

Under the Holding Company Act, we remain subject to certain restrictions that have the potential of limiting our diversification into non-utility businesses. Under the Holding Company Act, the sum of certain assets of all non-utility affiliates in a holding company system generally may not exceed 25% of the assets of all public utility affiliates in the system, subject to certain exemptions for energy-related assets.

In addition, the Holding Company Act precludes the acquisition of 10% or more of the voting shares of a holding company of a Wisconsin public utility unless the PSCW has first determined that the acquisition is in the best interests of utility customers, investors, and the public. This provision and other requirements of the Holding Company Act may delay or reduce the likelihood of a sale or change of control of WEC Energy Group. As a result, shareholders may be deprived of opportunities to sell some or all of their shares of our common stock at prices that represent a premium over market prices.

Risks Related to the Operation of Our Business

Public health crises, including epidemics and pandemics, could adversely affect our business functions, financial condition, liquidity, and results of operations.

Public health crises, including epidemics and pandemics, and any related government responses may adversely impact the economy and financial markets and could have a variety of adverse impacts on us, including a decrease in revenues; increased bad debt expense; increases in past due accounts receivable balances; and access to the capital markets at unreasonable terms or rates.

Public health crises, including epidemics and pandemics, and any related government responses could also impair our ability to develop, construct, and operate facilities. Risks include extended disruptions to supply chains and inflation, resulting in increased costs for labor, materials, and services, which could adversely impact our ability to implement our corporate strategy. We may also be adversely impacted by labor disruptions and productivity as a result of infections, employee attrition, and a reduced ability to replace departing employees as a result of employees who leave or forego employment to avoid any required precautionary measures.

Despite our efforts to manage the impacts of public health crises, including epidemics and pandemics, that may occur in the future, the extent to which they may affect us depends on factors beyond our knowledge or control. As a result, we are unable to determine the potential impact any such public health crises, including epidemics and pandemics, may have on our business plans and operations, liquidity, financial condition, and results of operations.

Our operations are subject to risks arising from the reliability of our electric generation, transmission, and distribution facilities, natural gas infrastructure

facilities, natural gas storage fields, renewable energy facilities, and other facilities, as well as the reliability of third-party transmission providers.

Our financial performance depends on the successful operation of our electric generation, natural gas and electric distribution facilities, natural gas storage fields, and renewable energy facilities. The operation of these facilities involves many risks, including operator error and the breakdown or failure of equipment or processes.

Potential breakdown or failure may occur due to severe weather (i.e., storms, tornadoes, floods, droughts, etc.); catastrophic events (i.e., fires, earthquakes, and explosions); public health crises, including epidemics and pandemics; significant changes in water levels in waterways; fuel supply or transportation disruptions; accidents; employee labor disputes; construction delays or cost overruns; delays in the replacement of aging infrastructure; shortages of or delays in obtaining equipment, material, and/or labor; performance below expected levels; operating limitations that may be imposed by environmental or other regulatory requirements; terrorist or other physical attacks; or cybersecurity intrusions. Any of these events could lead to substantial financial losses, including increased maintenance costs, unanticipated capital expenditures, and a reduction of revenues related to our non-utility renewable energy facilities. Because our electric generation and renewable energy facilities are interconnected with third-party transmission facilities, the operation of our facilities could also be adversely affected by events impacting their systems. Unplanned outages at our power plants may reduce our revenues, cause us to incur significant costs if we are required to operate our higher cost electric generators or purchase replacement power to satisfy our obligations, and could result in additional maintenance expenses.

Insurance, warranties, performance guarantees, or recovery through the regulatory process may not cover any or all of these lost revenues or increased expenses, which could adversely affect our results of operations and cash flows.

The operations of our natural gas utilities depend upon the availability of adequate interstate pipeline transportation capacity and natural gas.

Our natural gas utilities purchase almost all of their natural gas supply from interstate sources that must be transported to the applicable service territories. Interstate pipeline companies transport the natural gas to our natural gas utilities’ systems under firm service agreements that are designed to meet the requirements of their core markets. A significant disruption to interstate pipelines capacity or reduction in natural gas supply due to events including, but not limited to, operational failures or disruptions, hurricanes, tornadoes, floods, freeze-off of natural gas wells, terrorist or physical attacks, cyberattacks, other acts of war, or legislative or regulatory actions or requirements, including remediation related to integrity inspections or regulations and laws enacted to address climate change or other environmental matters, could reduce the normal interstate supply of natural gas and thereby significantly disrupt our operations and/or reduce earnings.

Our operations are subject to various conditions that can result in fluctuations in energy sales to customers, including customer growth and general economic conditions in our service areas, varying weather conditions, and energy conservation efforts.

Our results of operations and cash flows are affected by the demand for electricity and natural gas, which can vary greatly based upon:

- Fluctuations in customer growth and general economic conditions in our service areas. Customer growth and energy use can be negatively impacted by population declines as well as economic factors in our service territories, including workforce reductions, stagnant wage growth, changing levels of support from state and local government for economic development, business closings, and reductions in the level of business investment. Our electric and natural gas utilities are impacted by economic cycles and the competitiveness of the commercial and industrial customers we serve. Any economic downturn, disruption of financial markets, or reduced incentives by state government for economic development could adversely affect the financial condition of our customers and demand for their products or services. These risks could directly influence the demand for electricity and natural gas as well as the need for additional power generation and generating facilities. We could also be exposed to greater risks of accounts receivable write-offs if customers are unable to pay their bills.
- Weather conditions. Demand for electricity is greater in the summer and winter months when cooling and heating is necessary. In addition, demand for natural gas peaks in the winter heating season. As a result, our overall results may fluctuate substantially on a seasonal basis. In addition, milder temperatures during the summer cooling season and during the winter heating season may result in lower revenues and net income.
- Our customers' continued focus on energy conservation. Our customers' use of electricity and natural gas has decreased as a result of continued individual conservation efforts, including the use of more energy efficient technologies, and could be further reduced by new building codes, DERs, energy storage technology, and private solar. Customers could also voluntarily reduce their consumption of energy in response to decreases in their disposable income and increases in energy prices. Conservation of energy can be influenced by certain federal and state programs that are intended to influence how

consumers use energy. For example, several states, including Wisconsin and Michigan, have adopted energy efficiency targets to reduce energy consumption.

As part of our planning process, we estimate the impacts of changes in customer growth and general economic conditions, weather, and customer energy conservation efforts, but risks still remain. Any of these matters, as well as any regulatory delay in adjusting rates as a result of reduced sales from effective conservation measures or the adoption of new technologies, could adversely impact our results of operations and financial condition.

Our operations are subject to the effects of global climate change.

A changing climate creates uncertainty and could result in broad changes, both physical and financial in nature, to our service territories. If climate changes occur that result in extreme temperatures in our service territories, our financial results could be adversely impacted by lower electric and natural gas usage and higher natural gas costs. An extreme weather event could result in downed wires and poles or damage to other operating equipment, which could result in us incurring significant restoration costs and foregoing sales of energy and lost revenues. Extreme weather in summer could cause electric load to be interrupted or certain customers to be curtailed who participate in load management programs. Additionally, an extreme weather event could also cause the cost of natural gas purchased for our natural gas utility customers and for the use of fuel at our generation facilities to be temporarily driven significantly higher than our normal winter weather expectations. Although our utilities have regulatory mechanisms in place for recovering all prudently incurred natural gas costs, our regulators could disallow recovery or order the refund of any costs determined to be imprudent.

In addition, our operations could be adversely affected and our facilities placed at greater risk of damage should changes in global climate produce, among other possible conditions, unusual variations in temperature and weather patterns, which could result in more intense, frequent and extreme weather events, such as wind storms including derecho events, floods, tornadoes, snow and ice storms, or abnormal levels of precipitation. Extreme weather may result in unexpected increases in customer load, requiring us to procure additional power at wholesale prices for our retail operations, unpredictable curtailment of customer load by MISO to maintain grid reliability, or other grid reliability issues. Any of these events could lead to substantial financial losses including increased maintenance costs, unanticipated capital expenditures, or a reduction of revenues related to our non-utility renewable energy facilities. The cost of storm restoration efforts may also not be fully recoverable through the regulatory process.

Our corporate strategy may be impacted by policy and legal, technology, market, and reputational risks and opportunities that are associated with the transition to lower GHG emissions. In addition, changes in policy to combat climate change, including mitigation and adaptation efforts, and technology advancement, each of which can also accelerate the implications of a transition to lower emissions, may materially adversely impact our results of operations and cash flows through significant capital expenditures and investments in renewable generation.

Our operations and future results may be impacted by changing expectations and demands of our customers, regulators, investors, and other stakeholders, including heightened emphasis on environmental, social, and governance concerns.

Our ability to execute our strategy and achieve anticipated financial outcomes are influenced by the expectations of our customers, regulators, investors, and other stakeholders. Those expectations are based in part on the core fundamentals of affordability and reliability but are also increasingly focused on our ability to meet rapidly changing demands for new and varied products, services, and offerings. Additionally, the risks of global climate change continues to shape our customers’ sustainability goals and energy needs, as well as the investment and financing criteria of investors. Failure to meet these increasing expectations or to adequately address the risks and external pressures from regulators, customers, investors, and other stakeholders may impact our reputation and affect our ability to achieve favorable outcomes in future rate cases or our results of operations. Furthermore, the increasing use of social media may accelerate and increase the potential scope of negative publicity we might receive and could increase the negative impact on our reputation, business, results of operations, and financial condition.

As it relates to electric generation, a diversified fleet with increasingly clean generation resources may facilitate more efficient financing and lower costs. Conversely, jurisdictions utilizing more carbon-intensive generation such as coal may experience difficulty attracting certain investors and obtaining the most economical financing terms available. Furthermore, with this heightened emphasis on environmental, social, and governance concerns, and climate change in particular, there is an increased risk of litigation.

Our operations and corporate strategy may be adversely affected by supply chain disruptions and inflation.

Our business is dependent on the global supply chain to ensure that equipment, materials, and other resources are available to both expand and maintain services in a safe and reliable manner. Protracted, expanding or escalating regional conflicts, including the conflicts in Ukraine, Israel, and parts of the Middle East, as well as strained relationships between the United States and other countries related to such conflicts, could further contribute to current domestic and global supply chain disruptions that are delaying the delivery, and in some cases resulting in shortages of, materials, equipment, and other resources that are critical to our business operations. Failure to eliminate or manage the constraints in the supply chain may eventually impact the availability of items that are necessary to support normal operations as well as materials that are required to implement our corporate strategy for continued utility and infrastructure growth, including our renewable energy projects.

Moreover, prices of equipment, materials, and other resources have increased as a result of these supply chain disruptions and may continue to increase in the future, as a result of inflation. Increases in inflation raise our costs for labor, materials, and services, and failure to secure these resources on economically acceptable terms, as well as any regulatory delay in adjusting rates to account for increased costs, may adversely impact our financial condition and results of operations.

We are actively involved with multiple significant capital projects, which are subject to a number of risks and uncertainties that could adversely affect project costs and completion of construction projects.

Our business requires substantial capital expenditures for investments in, among other things, capital improvements to our electric generating facilities, electric and natural gas distribution infrastructure, natural gas and LNG storage, and other projects, including projects for environmental compliance. We also expect to continue constructing and investing in renewable energy generating facilities as part of the ESG Progress Plan and our goal to be net carbon neutral by 2050, including projects in our non-utility energy infrastructure segment. In addition, WBS continues to invest in technology and the development of software applications to support our businesses.

Achieving the intended benefits of any large construction project is subject to many uncertainties, some of which we will have limited or no control over, that could adversely affect project costs and completion time. Supply chain disruptions, including solar panel shortages and delays, increasing material costs, government tariffs, and other factors, could impact the timing of completion of our renewable projects. For example, the UFLPA's prohibition on imports of solar panels manufactured with certain silica-based products originating in Xinjiang, China, has delayed the release of solar panels to us for our renewables projects. Additional risks include, but are not limited to, the ability to adhere to established budgets and time frames; the availability of labor or materials at estimated costs; the ability of contractors to perform under their contracts; strikes; adverse weather conditions; potential legal challenges; changes in applicable laws or regulations; rising interest rates; the impact of public health crises, including epidemics and pandemics; other governmental actions; continued public and policymaker support for such projects; and events in the global economy.

Certain of these projects require the approval of our regulators. If construction of commission-approved projects should materially and adversely deviate from the schedules, estimates, and/or projections on which the approval was based, our regulators may deem the additional capital costs as imprudent and disallow recovery of them through rates, and otherwise available PTCs and ITCs for renewable energy projects could be lost or lose value. In addition, regulators, in a future rate proceeding, may alter the timing or amount of certain costs for which recovery is allowed, such as the case in the ICC's November 2023 rate orders for PGL and NSG.

Our subsidiaries sometimes enter into equipment purchase orders and construction contracts and incur engineering and design service costs in advance of receiving necessary regulatory approvals and/or siting or environmental permits. If any of these projects are canceled for any reason, including failure to receive necessary regulatory approvals and/or siting or environmental permits, significant cancellation penalties under the equipment purchase orders and construction contracts could occur. In addition, if any construction work or investments have been recorded as an asset, an impairment may need to be recorded in the event the project is canceled.

To the extent that delays occur, costs become unrecoverable, tax credits are lost or lose value, or we or third parties with whom we invest and/or partner otherwise become unable to effectively manage and complete capital projects, our results of operations, cash flows, and financial condition may be adversely affected.

Our operations are subject to risks beyond our control, including but not limited to, cybersecurity intrusions, terrorist or other physical attacks, acts of war, or unauthorized access to personally identifiable information.

We have been subject to attempted cyber attacks from time to time, and will likely continue to be subject to such attempted attacks; however, these prior attacks have not had a material impact on our system or business operations. Despite the implementation of security measures, all assets and systems are potentially vulnerable to disability, failures, or unauthorized access due to physical or cybersecurity intrusions caused by human error, vendor bugs, terrorist or other physical attacks (including potential attacks on our substations and other electric distribution equipment), acts of war, or other malicious acts. These threats could result in a full or partial disruption of our ability to generate, transmit, purchase, or distribute electricity or natural gas or cause environmental repercussions. If our assets or systems were to fail, be physically damaged, or be breached, and were not recovered in a timely manner, we may be unable to perform critical business functions, and data, including sensitive information, could be compromised. Cybersecurity attacks, including attacks targeting utility systems and other critical infrastructure may increase during periods of heightened or escalating geopolitical tensions.

We operate in an industry that requires the use of sophisticated information technology systems and network infrastructure, which in turn control an interconnected network of generation, distribution, and transmission systems shared with third parties. A successful physical or cybersecurity intrusion may occur despite our security measures or those we require of our vendors, including compliance with reliability and critical infrastructure protection standards. Successful cybersecurity intrusions, including those targeting the electronic control systems used at our generating facilities and electric and natural gas transmission, distribution, and storage systems, could disrupt our operations and result in loss of service to customers. Attacks may come through ransomware, software updates or patches, or firmware that hackers can manipulate. These intrusions may cause unplanned outages at our power plants, which may reduce our revenues or cause us to incur significant costs if we are required to operate our higher cost electric generators or purchase replacement power to satisfy our obligations, and could result in additional maintenance expenses. The risk of such intrusions may also increase our capital and operating costs as a result of having to implement increased security measures for protection of our information technology and infrastructure.

Our continued efforts to integrate, consolidate, and streamline our operations have also resulted in increased reliance on current and recently completed projects for technology systems. The failure to enhance existing information technology systems and implement new technology, could adversely affect our operations. We implement procedures to protect our systems, but we cannot guarantee that the procedures we have implemented to protect against unauthorized access to secured data and systems are adequate to safeguard against all security breaches. The failure of any of these or other similarly important technologies, or our inability to support, update, expand, and/or integrate these technologies across our subsidiaries could materially and adversely impact our operations, diminish customer confidence and our reputation, materially increase the costs we incur to protect against these risks, and subject us to possible financial liability or increased regulation or litigation.

Our business requires the collection and retention of personally identifiable information of our customers, shareholders, and employees, who expect that we will adequately protect such information. In some cases, we rely on third-party hosted services to support our business operations. Malicious actors may target these providers to disrupt the services they provide to us, or to use those third parties to attack us. Security breaches of our or our third-party service providers' systems may expose us to a risk of loss or misuse of confidential and proprietary information. A significant theft, loss, or fraudulent use of personally identifiable information may lead to potentially large costs to notify and protect the impacted persons, and/or could cause us to become subject to significant litigation, costs, liability, fines, or penalties, any of which could materially and adversely impact our results of operations as well as our reputation with customers, shareholders, and regulators, among others. In addition, we may be required to incur significant costs associated with governmental actions in response to such intrusions or to strengthen our information and electronic control systems. We may also need to obtain additional insurance coverage related to the threat of such intrusions.

Threats to our systems and operations continue to emerge as new ways to compromise components into our systems or networks are developed. Any operational disruption or environmental repercussions caused by on-going or future threats to our assets and technology systems could result in a significant decrease in our revenues or significant reconstruction or remediation costs, which could materially and adversely affect our results of operations, financial condition, and cash flows. The costs of repairing damage to our facilities, operational disruptions, protecting personally identifiable information, and notifying impacted persons, as well as related legal claims, may also not be recoverable in rates, may exceed the insurance limits on our insurance policies, or, in some cases, may not be covered by insurance.

Advances in technology, and legislation or regulations supporting such technology, could make our electric generating facilities less competitive and may impact the demand for natural gas.

Advances in new technologies that produce or store power or reduce power consumption are ongoing and include renewable energy technologies, customer-oriented generation, energy storage devices, and energy efficiency technologies. We generate power at central station power plants and utility-scale renewable generation facilities to achieve economies of scale and produce power at a competitive cost. Distributed generation technologies that produce power, including fuel cells, microturbines, wind turbines, solar cells, and related energy storage devices, have technologically improved and have become more cost competitive than they were in the past.

Recently enacted legislation, including the IRA and the Infrastructure Investment and Jobs Act, promotes the construction and cost-effectiveness of renewable energy generation, including distributed generation technologies for self-supply of electricity by our customers and third parties. Increased use of technologies such as private solar and battery storage in our service territories could reduce our recovery of fixed costs, could result in customers leaving the electric distribution system, and could cause an increase in customer net energy metering, which allows customers with private solar to receive bill credits for surplus power at the full retail amount. Over time, customer adoption of these technologies could result in our electric utilities not being able to fully recover the costs and investment in generation. In December 2022, the PSCW issued a declaratory ruling finding that a third-party financed DER is not a “public utility” under Wisconsin law. Although the finding was limited to the specific facts and circumstances of the lease presented in that petition and is being appealed, similar findings or a broader policy position could have a material adverse impact on our business operations.

Federal and state regulations and other efforts designed to promote and expand the use of distributed generation technologies also incentivize modernization of the electric distribution grid to, among other things, accommodate two-way flows of electricity and increase the grid's capacity to interconnect to these distributed generation technologies. Other legislation or regulations could be adopted supporting the use of these technologies at below cost or that permit third-party sales from such facilities, and allow these facilities to interconnect to our distribution system. There is also a risk that advances in technology will continue to reduce the costs of these alternative methods of producing power to a level that is competitive with that of central station and utility-scale renewable power production.

In addition, we cannot predict the effect that development of alternative energy sources or new technology may have on our natural gas operations, including whether subsidies of alternative energy sources by local, state, and federal governments might be expanded, or what impact this might have on the supply of or the demand for natural gas.

If these technologies become cost competitive and achieve economies of scale, our market share could be eroded, and the value of our generating facilities and natural gas distribution systems could be reduced. Advances in technology, or changes in legislation or regulations, could also change the channels through which our customers purchase or use power and natural gas, which could reduce our sales and revenues or increase our expenses.

We transport, distribute, and store natural gas, which involves numerous risks that may result in accidents and other operating risks and costs.

Inherent in natural gas distribution and storage activities are a variety of hazards and operational risks, such as leaks, accidental explosions, and mechanical problems, which could materially and adversely affect our results of operations, financial condition, and cash flows. In addition, these risks could result in serious injury to employees and non-employees, loss of human life, significant damage to property, environmental pollution, impairment of operations, and substantial losses to us. The location of natural gas pipelines and storage facilities near populated areas, including residential areas, commercial business centers, and industrial sites, could increase the level of damages resulting from these risks. These activities may subject us to litigation and/or administrative proceedings from time to time, which could result in substantial monetary judgments, fines, or penalties against us, or be resolved on unfavorable terms. Further, delays in the replacement of aging infrastructure as a result of the ICC's orders in the PGL and NSG rate cases may lead to increased costs and disruptions in operations that could also negatively impact our financial results.

We face risks related to our non-utility renewable energy facilities that could impact our return on investment or have a negative impact on our financial condition or results of operations.

The production of energy from wind and solar sites depends heavily on suitable weather conditions, which are variable. Wind conditions or solar irradiance that is unfavorable or below our estimates can cause electricity production, and therefore revenues and PTCs earned from non-utility renewable energy facilities, to be substantially below our expectations. We base our decisions about which sites to acquire and operate in part on the findings of studies of long-term meteorological data in the proposed area, which includes wind speed and prevailing direction or solar irradiance and seasonal variations of each. Actual conditions at these sites, however, may not conform to the results of these studies.

An increase in frequency and severity of weather conditions could cause disruptions to our sites to become more frequent and severe. Wind and solar equipment can be damaged by natural events such as lightning strikes that damage blades or in-ground electrical systems used to collect electricity from turbines or panels. Sites also may experience production shutdowns or delayed restoration of production during extreme weather conditions resulting in, among other things, damage to solar panels, icing on wind turbine blades, or restricted access to sites. The costs of repairing damage to these facilities may exceed the insurance limits on our insurance policies or may be outside the coverage afforded by our insurance policies. In addition, significant repair costs and/or continuous damage events could cause our insurance premiums to increase or lead to insurance coverage not being available at all. Damage to renewable facilities could also reduce operating capacity and cause the declaration of force majeure events. Customers may raise objections to force majeure declarations for these or similar operating issues. The failure to satisfy minimum operational or availability requirements under the PPAs, including PPAs related to projects under construction, could result in payment of damages or termination of the PPAs.

Lower wholesale market prices for electricity may adversely affect the financial results for certain of our renewable projects, depending on the structure of the related PPA. In addition, lower prices for other energy sources may reduce the demand for wind and solar energy development, which could adversely affect our growth prospects and financial condition. Wind and solar energy demand is affected by the price and availability of other fuels, including nuclear, coal, natural gas and oil, as well as other sources of renewable energy. Reduced government incentives for wind and solar energy, increases in operating and maintenance costs, new regulations, or incentives that favor other forms of energy could reduce the demand for renewable energy and may adversely affect our results of operations.

We do not own all the property and other sites on which our projects are located, and our rights may be subordinate to the rights of lienholders and leaseholders, which could have an adverse effect on our business and financial condition. Existing and future projects may be located on property on other sites occupied under long-term easements, leases, and rights of way. The ownership interests on these properties may be subject to mortgages securing loans or other liens and other easements, lease rights and rights of way of third parties that were created previously. As a result, some of our real property rights may be subordinate to the rights of these third parties, and the rights of our operating subsidiaries to use the property could be lost or curtailed.

We have entered into long-term PPAs for the majority of our non-utility renewable energy operations with a small number of customers where their payment is based on the energy produced, and in some cases the REC value created, by our facilities. Although initial agreements are often ten years or more, in the future we may not be able to replace expiring PPAs related to our non-utility renewable energy facilities with contracts on acceptable terms, including at prices that support operation of the facility on a profitable basis. Decreases in the retail prices of electricity supplied by traditional utilities or the pricing of other clean energy sources in the regions where our non-utility renewable energy facilities are located could harm our ability to offer competitive pricing and to sign PPAs with customers. If we are unable to replace an expiring PPA with an acceptable new revenue contract, we may be required to sell the power produced by the facility at wholesale prices and be exposed to market fluctuations and risks, or the affected site may temporarily or permanently cease operations. If we are unable to replace an expired distributed generation PPA with an acceptable new contract, we may be required to remove the renewable energy facility from the site or, alternatively, we may have to sell the assets, but the sale price may not be sufficient to replace the revenue previously generated by the renewable energy facility.

For some of our PPAs, the net amount paid by our PPA counterparties is impacted by wholesale prices at a market hub location different from the location of our renewable site. Systemic shortfalls and disruptions in transmission capacity can cause congestion between the two locations, which along with other factors, can cause price disparity between the market hub and site. This price disparity, known as basis risk, can be significant at times. We attempt to mitigate basis risk where possible, but hedging instruments are often not economically feasible or available in the quantities that we require. Basis risk cannot be entirely eliminated and can adversely affect our financial condition and results of operations.

Our non-utility renewable energy facilities are exposed to risks through participation in various regional power markets. Our ability to acquire new non-utility renewable energy facilities or generate revenue from existing facilities depends on having interconnection arrangements with transmission providers and power markets along with a reliable grid. We cannot predict whether transmission facilities will be expanded in specific markets to accommodate or increase competitive access to those markets. If a transmission network to which one or more of our facilities is connected experiences down time for system emergencies, force majeure, safety, reliability, maintenance or other operational reasons, we may lose revenues and PTCs and be exposed to non-performance penalties and claims from our customers. This risk of curtailment of our non-utility renewable energy facilities may result in a reduced return on our investments, and we may not be compensated for lost energy and ancillary services. As members of these RTOs, we are also subject to certain additional risks, including the allocation of losses among existing members caused by unreimbursed defaults of other participants in these markets and resolution of complaint cases seeking refunds of revenues previously earned by members of these markets. Existing, new, or changed rules of these RTOs could result in significant additional fees and increased costs for participation, including the cost of transmission facilities built by others due to changes in transmission rate design. In addition, these RTOs may assess costs resulting from improved transmission reliability, reduced transmission congestion, and firm transmission rights.

We are a holding company and rely on the earnings of our subsidiaries to meet our financial obligations.

As a holding company with no operations of our own, our ability to meet our financial obligations including, but not limited to, debt service, taxes, and other expenses, as well as pay dividends on our common stock, is dependent upon the ability of our subsidiaries to pay amounts to us, whether through dividends or other payments. Our subsidiaries are separate legal entities that are not required to pay any of our obligations or to make any funds available for that purpose or for the payment of dividends on our common stock. The ability of our subsidiaries to pay amounts to us depends on their earnings, cash flows, capital requirements, and general financial condition, as well as regulatory limitations. Prior to distributing cash to us, our subsidiaries have financial obligations that must be satisfied, including, among others, debt service and preferred stock dividends. In addition, each subsidiary's ability to pay amounts to us depends on any statutory, regulatory, and/or contractual restrictions and limitations applicable to such subsidiary, which may include requirements to maintain specified levels of debt or equity ratios, working capital, or other assets. Our utility subsidiaries are regulated by various state utility commissions, which generally possess broad powers to ensure that the needs of the utility customers are being met.

We may fail to attract and retain an appropriately qualified workforce.

We operate in an industry that requires many of our employees to possess unique technical skill sets. Events such as an aging workforce without appropriate replacements, the mismatch of skill sets to future needs, or the unavailability of contract resources may lead to operating challenges or increased costs. These operating challenges include lack of resources, loss of knowledge, and a lengthy time period associated with skill development. Failure to hire and obtain replacement employees, including the ability to transfer significant internal historical knowledge and expertise to the new employees, may adversely affect our ability to manage and operate our business. If we are unable to successfully attract and retain an appropriately qualified workforce, our results of operations could be adversely affected.

Our counterparties may fail to meet their obligations, including obligations under power purchase, natural gas supply, natural gas pipeline capacity, and transportation agreements.

We are exposed to the risk that counterparties to various arrangements who owe us money, electricity, natural gas, or other commodities or services will not be able to perform their obligations. Should the counterparties to these arrangements fail to perform or if capacity is inadequate, we may be required to replace the underlying commitment at current market prices or we may be unable to meet all of our customers' electric and natural gas requirements unless or until alternative supply arrangements are put in place. In such event, we may incur losses, and our results of operations, financial position, or liquidity could be adversely affected.

We have entered into several power purchase, natural gas supply, natural gas pipeline capacity, and transportation agreements with non-affiliated companies. Revenues are dependent on the continued performance by the counterparties of their obligations under these agreements. Although we have a comprehensive credit evaluation process and contractual protections, it is possible that one or more counterparties could fail to perform their obligations. If this were to occur, we generally would expect that any operating and other costs that were initially allocated to a defaulting customer's power purchase, natural gas supply, natural gas pipeline capacity, or transportation agreement would be reallocated among our retail customers. To the extent these costs are not allowed to be reallocated by our regulators or there is any regulatory delay in adjusting rates, a counterparty default under these agreements could have a negative impact on our results of operations and cash flows.

Risks Related to Economic and Market Volatility

Our business is dependent on our ability to successfully access capital markets on competitive terms and rates.

We rely on access to credit and capital markets to support our capital requirements, including expenditures for our utility infrastructure and to comply with future regulatory requirements, to the extent not satisfied by the cash flow generated by our operations. We have historically secured funds from a variety of sources, including the issuance of short-term and long-term debt securities. In addition, we rely on committed bank credit agreements as back-up liquidity, which allows us to access the low cost commercial paper markets. The availability of credit depends upon the ability of banks providing commitments under the facility to provide funds when their obligations to do so arise. Systemic risk of the banking system and the financial markets could prevent a bank from meeting its obligations under the credit agreements.

Successful implementation of our long-term business strategies, including capital investment, is dependent upon our ability to access the capital markets, including the banking and commercial paper markets, on competitive terms and rates. Continued elevation of, or further increases in, interest rates may adversely affect our results of operations and the ability of our regulated subsidiaries to earn their approved rates of return. High interest rates may also impair our ability to cost-effectively finance capital expenditures and to refinance maturing debt.

Our access to the credit and capital markets could be limited, or our cost of capital significantly increased, due to any of the following risks and uncertainties:

- A rating downgrade;
- Failure to comply with debt covenants;
- An economic downturn or uncertainty;
- Prevailing market conditions and rules;
- Political tensions, including civil unrest and election volatility;
- Concerns over foreign economic conditions;
- Changes in tax policy;
- Changes in investment criteria of institutional investors or banks, including any policies that would limit or restrict funding for companies with fossil fuel-related investments;
- War or the threat of war; and
- The overall health and view of the utility and financial institution industries.

If any of these risks or uncertainties limit our access to the credit and capital markets or significantly increase our cost of capital, it could limit our ability to implement, or increase the costs of implementing, our business plan, which, in turn, could materially and adversely affect our results of operations, cash flows, and financial condition, and could limit our ability to sustain our current common stock dividend level.

A downgrade in our credit ratings could negatively affect our ability to access capital at reasonable costs and/or require the posting of collateral.

There are a number of factors that impact our credit ratings, including, but not limited to, capital structure, regulatory environment, the ability to cover liquidity requirements, and other requirements for capital. We could experience a downgrade in ratings if the rating agencies determine that our level of business or financial risk, or that of any of our utilities or the utility industry, has deteriorated. Changes in rating methodologies by the rating agencies could also have a negative impact on credit ratings.

Any downgrade by the rating agencies could:

- Increase borrowing costs under certain existing credit facilities;
- Require the payment of higher interest rates in future financings and possibly reduce the pool of creditors;
- Decrease funding sources by limiting our access to the commercial paper market;
- Limit the availability of adequate credit support for our operations; and
- Trigger collateral requirements in various contracts.

Fluctuating commodity prices could negatively impact our operations.

Our operating and liquidity requirements are impacted by changes in the forward and current market prices of natural gas, coal, electricity, renewable energy credits, and ancillary services.

Our electric utilities burn natural gas in several of their electric generation plants and as a supplemental fuel at several coal-fired plants. In many instances the cost of purchased power is tied to the cost of natural gas. The cost of natural gas may increase because of disruptions in the supply of natural gas due to a curtailment in production or distribution, international market conditions, the demand for natural gas, and the availability of shale gas and potential regulations and/or other government action affecting its accessibility.

For Wisconsin retail electric customers, our utilities bear the risk for the recovery of fuel and purchased power costs within a symmetrical 2% fuel tolerance band compared to the forecast of fuel and purchased power costs established in their respective rate structures. Prudently incurred fuel and purchased power costs are recovered dollar-for-dollar from our Michigan retail electric customers and our wholesale electric customers. Our natural gas utilities receive dollar-for-dollar recovery of prudently incurred natural gas costs from their natural gas customers.

Changes in commodity prices could result in:

- Higher working capital requirements, particularly related to natural gas inventory, accounts receivable, and cash collateral postings;
- Reduced profitability to the extent that lower revenues, increased bad debt, and higher interest expense are not recovered through rates;
- Higher rates charged to our customers, which could impact our competitive position;
- Reduced demand for energy, which could impact revenues and operating expenses;
- Reduced growth prospects from renewable energy projects related to lower cost alternative energy sources and a limited number of purchasers of electricity; and
- Shutting down of generation facilities if the cost of generation exceeds the market price for electricity.

We may not be able to obtain an adequate supply of coal, which could limit our ability to operate our coal-fired facilities.

We own and operate several coal-fired electric generating units. Although we generally carry sufficient coal inventory at our generating facilities to protect against an interruption or decline in supply, there can be no assurance that the inventory levels will be adequate. While we have coal supply and transportation contracts in place, we cannot assure that the counterparties to these agreements will be able to fulfill their obligations to supply coal to us or that we will be able to take delivery of all the coal volume contracted for. Coal deliveries may occasionally be restricted because of rail congestion and maintenance, derailments, weather, public health crises, including epidemics and pandemics, and supplier financial hardship. Supplier financial hardship is a result of decreased demand for coal due to increased natural gas and renewable energy generation, the impact of environmental regulations, and environmental concerns related to coal-fired generation.

If we are unable to obtain our coal requirements under our coal supply and transportation contracts, we may be required to purchase coal at higher prices or we may be forced to reduce generation at our coal-fired units, which could lead to increased fuel costs. The increase in fuel costs could result in either reduced margins on net sales into the MISO Energy Markets, a reduction in the volume of net sales into the MISO Energy Markets, and/or an increase in net power purchases in the MISO Energy Markets. There is no guarantee that we would be able to fully recover any increased costs in rates or that recovery would not otherwise be delayed, either of which could adversely affect our results of operations and cash flows.

Our use of derivative contracts could result in financial losses.

We use derivative instruments such as swaps, options, futures, and forwards to manage commodity price exposure. We could recognize financial losses as a result of volatility in the market value of these contracts or if a counterparty fails to perform. These risks are managed through risk management policies, which might not work as planned and cannot entirely eliminate the risks associated with these activities. In addition, although the hedging programs of our utilities must be approved by the various state commissions, derivative contracts entered into for hedging purposes might not offset the underlying exposure being hedged as expected, resulting in financial losses. In the absence of actively quoted market prices and pricing information from external sources, the value of these financial instruments can involve management's judgment or use of estimates. Changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

Restructuring in the regulated energy industry and competition in the retail and wholesale markets could have a negative impact on our business and revenues.

The regulated energy industry continues to experience significant structural changes. Deregulation or other changes in law in the states where we serve our customers could allow third-party suppliers to contract directly with customers for their natural gas and electric supply requirements. In addition, legislation or regulation that supports distributed energy technologies or that allows third party sales from such technologies could result in further competition. This increased competition in the retail and wholesale markets could have a material adverse financial impact on us.

Certain jurisdictions in which we operate, including Michigan and Illinois, have adopted retail choice. Under Michigan law, our retail electric customers may choose an alternative electric supplier to provide power supply service. The law limits customer choice to 10% of our Michigan retail load. The iron ore mine located in the Upper Peninsula of Michigan is excluded from this cap. When a customer switches to an alternative electric supplier, we continue to provide distribution and customer service functions for the customer. Although Illinois has adopted retail choice, there is currently little or no impact on the net income of our Illinois utilities as they still earn a distribution charge for transporting the natural gas for these customers. It is uncertain whether retail choice might be implemented in Wisconsin or Minnesota.

The FERC continues to support the existing RTOs that affect the structure of the wholesale market within these RTOs. In connection with its status as a FERC-approved RTO, MISO implemented bid-based energy markets that are part of the MISO Energy Markets. All market participants, including us, must submit day-ahead and/or real time bids and offers for energy at locations across the MISO region. MISO then calculates the most efficient solution for all of the bids and offers made into the market that day and establishes an LMP that reflects the market price for energy. We are required to follow MISO's instructions when dispatching generating units to support MISO's responsibility for maintaining the stability of the transmission system. MISO also implemented an ancillary services market for operating reserves that schedules energy and ancillary services at the same time as part of the energy market, allowing for more efficient use of generation assets in the MISO Energy Markets. These market designs continue to have the potential to increase the costs of transmission, the costs associated with inefficient generation dispatching, the costs of participation in the MISO Energy Markets, and the costs associated with estimated payment settlements.

The FERC rules related to transmission are designed to facilitate competition in the wholesale electricity markets among regulated utilities, non-utility generators, wholesale power marketers, and brokers by providing greater flexibility and more choices to wholesale customers, including initiatives designed to encourage the integration of renewable sources of supply. In addition, along with transactions contemplating physical delivery of energy, financial laws and regulations impact hedging and trading based on futures contracts and derivatives that are traded on various commodities exchanges, as well as over-the-counter. Technology changes in the power and fuel industries also have significant impacts on wholesale transactions and related costs. We currently cannot predict the impact of these and other developments or the effect of changes in levels of wholesale supply and demand, which are driven by factors beyond our control.

Volatility in the securities markets, interest rates, changes in assumptions, market conditions, and other factors may impact the performance of our benefit plan holdings and other investment funds.

We have significant obligations related to pension and OPEB plans. If we are unable to successfully manage our benefit plan assets and medical costs, our cash flows, financial condition, or results of operations could be adversely impacted. Our cost of providing these plans is dependent upon a number of factors, including actual plan experience, changes made to the plans, and assumptions concerning the future. Types of assumptions include earnings on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plans, future government regulation, estimated withdrawals by retirees, and our required or voluntary contributions to the plans. Plan assets are subject to market fluctuations and may yield returns that fall below projected return rates. In addition, medical costs for both active and retired employees may increase at a rate that is significantly higher than we currently anticipate. Our funding requirements could be impacted by a decline in the market value of plan assets, changes in interest rates, changes in demographics (including the number of retirements), or changes in life expectancy assumptions.

In addition, we maintain rabbi trusts to fund our deferred compensation plans and other investments funds, which from time to time, hold equity and debt investments that are subject to market fluctuations. Decreases in investment performance of these assets could materially adversely affect our results of operations, cash flows, and financial condition.

General Risks

We have recorded goodwill and other long-lived assets, including intangible assets, that could become impaired.

We assess goodwill for impairment on an annual basis or whenever events or circumstances occur that would more than likely indicate that the carrying amount of our reporting unit's net assets exceeds the reporting unit's fair value. At December 31, 2023, our goodwill was $3,052.8 million. Other long-lived assets, including intangible assets, are evaluated for impairment on an annual basis or whenever events or circumstances occur that indicate that an asset's carrying value may not be recoverable. If goodwill or other long-lived assets are deemed to be impaired, we may be required to incur a non-cash charge to earnings that could materially adversely affect our results of operations.

See the risk factor titled "Our business is significantly impacted by governmental regulation and oversight" for more information about long-lived assets that were impaired as a result of the ICC's November 2023 rate orders for PGL and NSG.

We may be unable to obtain insurance on acceptable terms or at all, and the insurance coverage we do obtain may not provide protection against all significant losses.

Our ability to obtain insurance, as well as the cost and coverage of such insurance, could be affected by developments affecting our business; international, national, state, or local events; and the financial condition of insurers and our contractors that are required to acquire and maintain insurance for our benefit. Insurance coverage may not continue to be available at all or at rates or terms similar to those presently available to us. In addition, our insurance may not be sufficient or effective under all circumstances and against all hazards or liabilities to which we may be subject. Any losses for which we are not fully insured or that are not covered by insurance at all could materially adversely affect our results of operations, cash flows, and financial position.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 1C. CYBERSECURITY

Our Board of Directors is responsible for general oversight of our risk environment and associated management policies and practices. The Board of Directors has delegated to its AOC the responsibility for oversight of our major risk categories and exposures, including with respect to cybersecurity, and management's processes to monitor and control them. The AOC meets regularly throughout the year and receives and reviews various risk management reports about IT/OT cybersecurity, data security, and physical security risk management reports, and discusses these matters with appropriate management and other personnel. The CEO and CAO regularly report to the AOC and the Board of Directors about cybersecurity matters and risks as well as the adequacy and effectiveness of the cybersecurity risk management program.

To foster an enterprise-wide approach to risk management, we have established an ERSC chaired by our CEO and comprised of a cross-functional group of senior leaders from across our organization. The ERSC regularly reviews key risk areas and oversees the development and implementation of effective compliance and risk management practices, including the use of internal and external audits. Our Board of Directors and the AOC receive reports regarding the same. Governance of our cybersecurity risk management program is overseen by the ERSC, along with steering committees for information security, operational technology security, third-party vendor security controls, Sarbanes-Oxley security controls, and North American Electric Reliability Corporation Critical Infrastructure Protection compliance.

Our CAO is responsible for enterprise-wide information technology services and cybersecurity system strategy. In this capacity, the CAO oversees the cybersecurity risk management program, which is maintained and implemented by the Enterprise Security Director. Our CAO has 24 years of experience at the company, during which time she has held a number of management and leadership positions, including Chief Information Officer, through which she has developed expertise in our IT/OT cybersecurity, data security, and physical security environment and risk profile.

The Enterprise Security Director, in collaboration with her team, is responsible for IT/OT cybersecurity, data security, and physical security. The Enterprise Security Director identifies, evaluates, and facilitates mitigation of cyber, data, and physical security risks and reports on cybersecurity matters and risks to the ERSC and the AOC. Our Enterprise Security Director has over 26 years of experience in IT/OT cybersecurity, data security and physical security, and is a certified information system security professional. She is also a member of numerous state and national cybersecurity organizations.

Cybersecurity Risk Management Program

Our cybersecurity-related risks are managed through monitoring, defense and response tools, audits and assessments of the program’s effectiveness, industry collaboration, and employee training and awareness. Our cybersecurity risk management program utilizes the cybersecurity framework and maturity models from the National Institute of Standards and Technology and the United States Department of Energy to continually assess its maturity. This includes regular internal security audits and vulnerability assessments, as well as regular engagement with third-party security experts for external assessments of our security controls, including technical, physical, and social aspects. To better comprehend the scope and magnitude of any active threats to our industry and nation and their potential impact on our IT/OT systems, we communicate with other utility companies, government agencies, and other sectors of the economy concerning cybersecurity incidents. All employees are required to complete training annually regarding information security and acceptable use of corporate electronic resources. Annual role-based cybersecurity training as well as ongoing participation in a corporate phishing campaign program, is also required of employees and contractors. In addition, as part of the cybersecurity program, we have established controls and procedures to assess the adequacy of controls in place at third-party vendors to protect corporate information, including restricted and confidential restricted information we provide to third-party vendors, their employees, or authorized agents. These third-party vendors are also subject to a background investigation prior to being granted physical or electronic access to the company's private property, or physical access to customer premises on behalf of the company.

As part of the cybersecurity program, we have adopted a cybersecurity incident response plan (the “Plan”) designed to identify, evaluate, respond to, and resolve cybersecurity incidents impacting IT/OT systems. Pursuant to the terms of the Plan, we have established a CSIRT Steering Committee which includes, among others, the Chief Financial Officer, CAO, and the Enterprise Security Director. The CSIRT Steering Committee is responsible for overseeing and implementing the Plan in the event of a cybersecurity threat or incident and provides updates regarding the status of the response to senior management, including the CEO, who provide updates and reports regarding cybersecurity incidents to the AOC and/or the Board of Directors at regularly scheduled meetings or more frequently, as needed.

In response to an identified cybersecurity incident, or as it deems appropriate, the CSIRT Steering Committee will assemble and oversee a CSIRT, comprised of appropriate personnel and subject matter experts depending on the scope and severity of the incident, relevant or impacted business units and entities, and type of information or systems potentially compromised by the cybersecurity incident. When assembled, the CSIRT is responsible for developing and implementing an overall response strategy to contain, control, and remediate the cybersecurity incident, including securing our affected systems and/or information, mitigating harmful effects of the incident, preventing further compromises, and communicating information to affected parties, regulatory agencies and law enforcement, as necessary. The CSIRT may seek assistance from or engage external support providers including legal counsel, outside technology or forensic experts, investigation service providers, and others, as appropriate, to assist in the response to the incident, based on its nature and scope. Pursuant to the Plan and at the direction of the CAO, the Enterprise Security Director will conduct a post-incident remediation analysis and report findings to the CSIRT Steering Committee. The Plan is tested and reviewed at least annually.

We have been subject to attempted cybersecurity attacks from time to time, and will likely continue to be subject to such attempted attacks; however, these prior attacks have not had a material impact on our system or business operations. For information about cybersecurity risks to our business, see Item 1A. Risk Factors and the risk factor titled "Our operations are subject to risks beyond our control, including but not limited to, cybersecurity intrusions, terrorist or other physical attacks, acts of war, or unauthorized access to personally identifiable information."

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ITEM 2. PROPERTIES

We own our principal properties outright. However, the major portion of our electric utility distribution lines, steam utility distribution mains, and natural gas utility distribution mains and services are located on or under streets and highways, on land owned by others, and are generally subject to granted easements, consents, or permits.

A. REGULATED

Electric Facilities

The following table summarizes information on our electric generation facilities, including owned and jointly owned facilities, as of December 31, 2023:

Name	Location	Fuel	Number of Generating Units	Capacity In MW [(1)]
Natural gas-fired plants				
PWGS	Port Washington, WI	Natural Gas	2	1,217 (3)
Fox Energy Center	Wrightstown, WI	Natural Gas	3	581
Concord	Watertown, WI	Natural Gas/ Oil	4	365
Paris	Union Grove, WI	Natural Gas/ Oil	4	361
VAPP	Milwaukee, WI	Natural Gas	2	275
Germantown	Germantown, WI	Natural Gas/ Oil	5	263
Whitewater	Whitewater, WI	Natural Gas/ Oil	1	243
De Pere Energy Center	De Pere, WI	Natural Gas/ Oil	1	166
West Marinette	Marinette, WI	Natural Gas	3	158
Weston	Rothschild, WI	Natural Gas	7	130
F. D. Kuester	Negaunee, MI	Natural Gas	7	128
West Riverside	Beloit, WI	Natural Gas	2	85 (2)
Pulliam	Green Bay, WI	Natural Gas	1	82
A. J. Mihm	Baraga, MI	Natural Gas	3	55
Total natural gas-fired plants			45	4,109
Coal-fired plants				
OCPP	Oak Creek, WI	Coal	4	1,103 (7)
ERGS	Oak Creek, WI	Coal	2	1,082 (2) (3)
Weston	Rothschild, WI	Coal	2	713 (2) (7)
Columbia	Portage, WI	Coal	2	312 (2) (7)
Total coal-fired plants			10	3,210
Wind facilities				
Glacier Hills Wind Park	Cambria, WI	Wind	90	162
Blue Sky Green Field Wind Park	Fond du Lac, WI	Wind	88	145
Crane Creek Wind Farm	Howard County, IA	Wind	66	99
Red Barn	Grant County, WI	Wind	28	82 (2)
Forward Wind	Fond du Lac County, WI	Wind	86	62 (2)
Montfort Wind Energy Center	Montfort, WI	Wind	20	30
Total wind facilities			378	580
Solar facilities				
	Manitowoc			

(1) Capacity for our electric generation facilities, other than wind and solar generating facilities, is based on rated capacity, which is the net power output under average operating conditions with equipment in an average state of repair as of a given month in a given year. Values are primarily based on the net dependable expected capacity ratings for summer 2024 established by tests and may change slightly from year to year. The summer period is the most relevant for capacity planning purposes. This is a result of continually reaching demand peaks in the summer months, primarily due to air conditioning demand. Capacity for wind generating facilities is based on nameplate capacity, which is the amount of energy a turbine should produce at optimal wind speeds. Capacity for solar generating facilities is based on nameplate capacity, which is the maximum output that a generator should produce at continuous full power.

(2) Our subsidiaries jointly own these facilities with various other unaffiliated entities. The capacity indicated for each of these units is equal to our subsidiaries' portion of total plant capacity based on its percent of ownership. See Note 8, Jointly Owned Utility Facilities, for more information on our ownership interests.

(3) These facilities are part of the Company's non-utility energy infrastructure segment. See B. Non-Utility Energy Infrastructure Segment below.

(4) All of our hydroelectric facilities follow FERC guidelines and/or regulations.

(5) WRPC owns and operates the Castle Rock and Petenwell units. WPS holds a 50.0% ownership interest in WRPC and is entitled to 50.0% of the total capacity at Castle Rock and Petenwell. WPS's share of capacity for Castle Rock and Petenwell is 7.0 MWs and 10.3 MWs, respectively.

(6) WE has a biomass power plant that uses wood waste and wood shavings to produce electric power as well as steam to support the paper mill's operations. Fuel for the power plant is supplied by both the paper mill and through contracts with biomass suppliers. The plant also has the ability to burn natural gas if wood waste and wood shavings are not available.

(7) We expect to retire approximately 1,800 MWs of additional fossil-fueled generation by the end of 2031, which includes the planned retirement in 2024-2025 of OCPP Units 5-8, the planned retirement by June 2026 of jointly-owned Columbia Units 1-2, and the planned retirement in 2031 of Weston Unit 3.

As of December 31, 2023, we operated approximately 35,500 miles of overhead distribution lines and approximately 36,500 miles of underground distribution cable, as well as approximately 430 electric distribution substations and approximately 523,700 line transformers.

Natural Gas Facilities

At December 31, 2023, our natural gas properties were located in Illinois, Wisconsin, Minnesota, and Michigan, and consisted of the following:

- Approximately 46,400 miles of natural gas distribution mains,
- Approximately 1,700 miles of natural gas transmission mains,
- Approximately 2.4 million natural gas lateral services,
- Approximately 490 natural gas distribution and transmission gate stations,

- Approximately 69.3 Bcf of working gas capacities in underground natural gas storage fields:
  - Bluewater, 27.6 Bcf of fields located in southeastern Michigan,
  - Manlove, a 38.8 Bcf field located in central Illinois,
  - Partello, a 2.9 Bcf field located in southern Michigan,
- A 2.0 Bcf LNG plant located in central Illinois,
- A 1.0 Bcf LNG plant located in southern Wisconsin,
- A peak-shaving facility that can store the equivalent of approximately 80 MDth in liquefied petroleum gas located in Illinois, and
- LNG storage plants, located in Wisconsin, with a total send-out capability of 173,600 Dth per day.

Our natural gas distribution and gas storage systems included distribution mains and transmission mains connected to the pipeline transmission systems of Alliance Pipeline, ANR Pipeline Company, Centra Pipelines, Consumers Energy, DTE Gas Company, Enbridge Gas Inc., Great Lakes Transmission Company, Guardian Pipeline L.L.C., Interstate Power and Light Company, Kinder Morgan Illinois Pipeline, Midwestern Gas Pipeline Company, Natural Gas Pipeline Company of America, Nicor Gas, Northern Border Pipeline Company, Northern Natural Gas Company, Northwest Gas of Cottonwood County, LLC, Northwestern Energy, Panhandle Gas Transmission, SEMCO, Trunkline Gas Pipeline, Vector Pipeline Company, and Viking Gas Transmission. Our LNG storage plants convert and store, in liquefied form, natural gas received during periods of low consumption.

We also own office buildings, natural gas regulating and metering stations, and major service centers, including garage and warehouse facilities, in certain communities we serve. Where distribution lines and services and natural gas distribution mains and services occupy private property, we have in some, but not all instances, obtained consents, permits, or easements for these installations from the apparent owners or those in possession of those properties, generally without an examination of ownership records or title.

Steam Facilities

As of December 31, 2023, the steam system supplied by the VAPP consisted of approximately 40 miles of both high pressure and low pressure steam piping, approximately four miles of walkable tunnels, and other pressure regulating equipment.

General

Substantially all of PGL's and NSG's properties are subject to the lien of the respective company's mortgage indenture for the benefit of bondholders.

B. NON-UTILITY ENERGY INFRASTRUCTURE SEGMENT

The non-utility energy infrastructure segment includes We Power, Bluewater, and WECI. We Power and Bluewater are considered non-utility energy infrastructure operations, however, their facilities are shown in the regulated section. We Power owns and leases generating facilities to WE. We Power's share of the ERGS units and both PWGS units are being leased to WE under long-term leases. Bluewater provides natural gas storage and hub services primarily to WE, WPS, and WG. WECI has ownership interests in eight wind generating facilities and one solar generating facility. For more information on recent and pending renewable facility acquisitions, see Note 2, Acquisitions.

The following table summarizes information on WECI's renewable generating facilities as of December 31, 2023:

Name	Location	Ownership Percentage (%) [1]	Number of Generating Units	Nameplate Capacity In MW [2]
Renewable generating facilities				
Thunderhead	Antelope and Wheeler Counties, Nebraska	90 %	108	299.3
Blooming Grove	McLean County, Illinois	90 %	94	260.9
Sapphire Sky	McLean County, Illinois	90 %	64	251.0
Samson I	Lamar, Franklin, Hopkins and Red River Counties, Texas	80 % [3]	340	250.0
Upstream	Antelope County, Nebraska	90 %	81	202.5
Jayhawk	Bourbon and Crawford Counties, Kansas	90 %	70	197.4
Tatanka Ridge	Deuel County, South Dakota	85 %	56	154.8
Bishop Hill III	Henry County, Illinois	90 %	53	132.1
Coyote Ridge	Brookings County, South Dakota	80 %	39	97.4
Total renewable generating facilities			905	1,845.4

(1) Invenergy Wind LLC operates these renewable facilities.

(2) Nameplate capacity is the amount of energy a source should produce under optimal conditions, such as optimal wind speeds or solar irradiance.

(3) In January 2024, WECI acquired an additional 10% ownership interest in Samson I.

ITEM 3. LEGAL PROCEEDINGS

The following should be read in conjunction with Note 24, Commitments and Contingencies, and Note 26, Regulatory Environment, in this report for additional information on material legal proceedings and matters related to us and our subsidiaries.

In addition to those legal proceedings discussed in Note 24, Commitments and Contingencies, Note 26, Regulatory Environment, and below, we are currently, and from time to time, subject to claims and suits arising in the ordinary course of business. Although the results of these additional legal proceedings cannot be predicted with certainty, management believes, after consultation with legal counsel, that the ultimate resolution of these proceedings will not have a material impact on our financial statements.

Employee Retirement Savings Plan Matter

In May 2022, a putative class action, Munt, et al. v. WEC Energy Group, Inc., et al., was filed in the United States District Court for the Eastern District of Wisconsin - Milwaukee Division. The plaintiffs allege that WEC Energy Group and others breached their fiduciary duties with respect to the operation and oversight of the Employee Retirement Saving Plan (the “Plan”) in violation of the Employee Retirement Income Security Act of 1974, as amended. The class is alleged to be participants in the Plan from May 10, 2016 through the date of judgment. The complaint seeks injunctive relief, damages, interest, costs, and attorneys' fees. The Company is vigorously defending against the allegations made in this lawsuit and intends to continue to do so.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

The names, ages, and positions of our executive officers are listed below along with their business experience during the past five years. All officers are appointed until their resignation, death, or removal pursuant to our Bylaws. There are no family relationships among these officers, nor is there any agreement or understanding between any officer and any other person pursuant to which the officer was selected.

Joshua M. Erickson. Age 51.
- WEC Business Services (a centralized service company of WEC Energy Group) – Vice President and Deputy General Counsel since August 2021. Director-Legal Services – Corporate and Finance from June 2015 through July 2021.

Robert M. Garvin. Age 57.
- WEC Energy Group — Executive Vice President - External Affairs since June 2015.
- WEC Business Services (a centralized service company of WEC Energy Group) – Executive Vice President - External Affairs since January 2019.

William J. Guc. Age 54.
- WEC Energy Group — Controller since October 2015. Vice President since June 2015.
- WE — Vice President and Controller since October 2015. Assistant Corporate Secretary since January 2020.

Margaret C. Kelsey. Age 59.
- WEC Energy Group — Executive Vice President, Corporate Secretary and General Counsel since January 2018.
- WE — Executive Vice President, Corporate Secretary and General Counsel since January 2018. Director since January 2018.

Gale E. Klappa. Age 73.
- WEC Energy Group — Executive Chairman since February 2019. Chairman of the Board and Chief Executive Officer from October 2017 to February 2019, and from May 2004 to May 2016. Non-Executive Chairman of the Board from May 2016 to October 2017. President from April 2003 to August 2013. Director since December 2003.
- WE — Director since January 2018, and from December 2003 to May 2016. Chairman of the Board from January 2018 to February 2019, and from May 2004 to May 2016. Chief Executive Officer from January 2018 to February 2019, and from August 2003 to May 2016. President from April 2003 to June 2015.

Daniel P. Krueger. Age 58.
- WEC Business Services (a centralized service company of WEC Energy Group) — Executive Vice President - WEC Infrastructure since January 2019.

Scott J. Lauber. Age 58.
- WEC Energy Group — President and Chief Executive Officer since February 1, 2022. Senior Executive Vice President and Chief Operating Officer from June 2020 to January 31, 2022. Senior Executive Vice President and Chief Financial Officer from October 2019 to June 2020. Senior Executive Vice President, Chief Financial Officer and Treasurer from February

2019 to October 2019. Executive Vice President, Chief Financial Officer and Treasurer from October 2018 to February 2019. Director since February 1, 2022.
- WE — Chairman of the Board and Chief Executive Officer since February 1, 2022. President since January 1, 2022. Executive Vice President from June 2020 to December 31, 2021. Executive Vice President and Chief Financial Officer from October 2019 to June 2020. Executive Vice President, Chief Financial Officer and Treasurer from October 2018 to October 2019. Director since April 2016.

Xia Liu. Age 54.
- WEC Energy Group — Executive Vice President and Chief Financial Officer since June 2020.
- WE — Executive Vice President and Chief Financial Officer since June 2020. Director since June 2020.
- CenterPoint Energy, Inc. — Senior Advisor from April 2020 to May 2020. Executive Vice President and Chief Financial Officer from April 2019 to April 2020. CenterPoint Energy, Inc. is a public utility holding company whose operating subsidiaries provide electric and natural gas service to customers in parts of the South and Midwest.
- Georgia Power Company — Executive Vice President, Chief Financial Officer and Treasurer from October 2017 to April 2019. Georgia Power Company is a utility subsidiary of The Southern Company that provides electric service to customers throughout Georgia.

William Mastoris. Age 60.
- WEC Business Services (a centralized service company of WEC Energy Group) – Executive Vice President – Customer Service and Operations since December 2021. Vice President – Supply Chain and Fleet from January 2019 through November 2021. Director since November 2021.
- WE – Executive Vice President – Customer Service and Operations since December 2021. Director since November 2021.

Molly A. Mulroy. Age 48.
- WEC Business Services (a centralized service company of WEC Energy Group) – Executive Vice President and Chief Administrative Officer since August 2021. Vice President and Chief Information Officer from January 2019 through July 2021. Director since November 2021.

Anthony L. Reese. Age 42.
- WEC Energy Group — Vice President and Treasurer since October 2019.
- WE — Vice President and Treasurer since October 2019.
- PGL – Controller - Illinois from September 2015 to September 2019.

Mary Beth Straka. Age 59.
- WEC Energy Group — Senior Vice President - Corporate Communications and Investor Relations since June 2015.

Certain executive officers also hold officer and/or director positions at WEC Energy Group's other significant subsidiaries.

PART II

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

Number of Common Shareholders

As of January 31, 2024, based upon the number of WEC Energy Group shareholder accounts (including accounts in our stock purchase and dividend reinvestment plan), we had approximately 36,000 registered shareholders.

Common Stock Listing and Trading

Our common stock is listed on the New York Stock Exchange under the ticker symbol "WEC."

Common Stock Dividends of WEC Energy Group, Inc.

We review our dividend policy on a regular basis. Subject to any regulatory restrictions or other limitations on the payment of dividends, future dividends will be at the discretion of the Board of Directors and will depend upon, among other factors, earnings, financial condition, and other requirements. For more information on our dividends, including restrictions on the ability of our subsidiaries to pay us dividends, see Note 11, Common Equity.

ITEM 6. RESERVED

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

CORPORATE DEVELOPMENTS

Introduction

We are a diversified holding company with natural gas and electric utility operations (serving customers in Wisconsin, Illinois, Michigan, and Minnesota), an approximately 60% equity ownership interest in ATC (a for-profit electric transmission company regulated by FERC and certain state regulatory commissions), and non-utility energy infrastructure operations through We Power (which owns generation assets in Wisconsin that it leases to WE), Bluewater (which owns underground natural gas storage facilities in Michigan), and WECI, which holds ownership interests in several renewable generating facilities.

Corporate Strategy

Our goal is to continue to build and sustain long-term value for our shareholders and customers by focusing on the fundamentals of our business: environmental stewardship; reliability; operating efficiency; financial discipline; exceptional customer care; and safety. Our capital investment plan for efficiency, sustainability and growth, referred to as our ESG Progress Plan, provides a roadmap for us to achieve this goal. It is an aggressive plan to cut emissions, maintain superior reliability, deliver significant savings for customers, and grow our investment in the future of energy.

Throughout our strategic planning process, we take into account important developments, risks and opportunities, including new technologies, customer preferences and affordability, energy resiliency efforts, and sustainability.

Creating a Sustainable Future

Our ESG Progress Plan includes the retirement of older, fossil-fueled generation, to be replaced with zero-carbon-emitting renewables and clean natural gas-fired generation. The retirements will contribute to meeting our goals to reduce CO_2 emissions from our electric generation. When taken together, the retirements and new investments in renewables and clean generation should better balance our supply with our demand, while maintaining reliable, affordable energy for our customers.

We have announced goals to achieve reductions in carbon emissions from our electric generation fleet by 60% by the end of 2025 and by 80% by the end of 2030, both from a 2005 baseline. We expect to achieve these goals by continuing to make operating refinements, retiring less efficient generating units, and executing our capital plan. Over the longer term, the target for our generation fleet is to be net carbon neutral by 2050.

As part of our path toward these goals, we have started implementing co-firing with natural gas at the ERGS coal-fired units. By the end of 2030, we expect to use coal as a backup fuel only, and we believe we will be in a position to eliminate coal as an energy source by the end of 2032.

We already have retired more than 1,900 MWs of fossil-fueled generation since the beginning of 2018, which included the 2019 retirement of the PIPP as well as the 2018 retirements of the Pleasant Prairie power plant, the Pulliam power plant, and the jointly-owned Edgewater Unit 4 generating units. See Note 6, Regulatory Assets and Liabilities, for more information related to these power plant retirements. We expect to retire approximately 1,800 MWs of additional fossil-fueled generation by the end of 2031, which includes the planned retirement in 2024-2025 of OCPP Units 5-8, the planned retirement by June 2026 of jointly-owned Columbia Units 1 and 2, and the planned retirement in 2031 of Weston Unit 3. See Note 7, Property, Plant, and Equipment, for more information related to planned power plant retirements.

In addition to retiring these older, fossil-fueled plants, we expect to invest approximately $7.0 billion from 2024-2028 in regulated renewable energy in Wisconsin. Our plan is to replace a portion of the retired capacity by building and owning zero-carbon-emitting renewable generation facilities that are anticipated to include the following new investments:

- 2,700 MWs of utility-scale solar;
- 880 MWs of wind; and
- 250 MWs of battery storage.

We also plan on investing in a combination of clean, natural gas-fired generation, including:

- 1,125 MWs of combustion turbines;
- 132 MWs of RICE natural gas-fueled generation; and
- the purchase of 100 MWs of additional capacity in West Riverside.

For more details, see Liquidity and Capital Resources – Cash Requirements – Significant Capital Projects.

In December 2018, WE received approval from the PSCW for two renewable energy pilot programs. The Solar Now pilot is expected to add a total of 35 MWs of solar generation to WE's portfolio, allowing non-profit and governmental entities, as well as commercial and industrial customers, to site utility owned solar arrays on their property. Under this program, WE has energized 28 Solar Now projects and currently has another one under construction, together totaling more than 30 MWs. The second program, the DRER pilot, is designed to allow large commercial and industrial customers to access renewable resources that WE would operate. The DRER pilot is intended to help these larger customers meet their sustainability and renewable energy goals, and could add up to 35 MWs of renewables to WE's portfolio. In July 2023, the PSCW approved the Renewable Pathway Pilot, the third renewable energy program. This program allows WE and WPS commercial and industrial customers to subscribe to a portion of a utility-scale, Wisconsin-based renewable energy generating facility for up to 125 MWs at WE and 40 MWs at WPS.

In August 2021, the PSCW approved pilot programs for WE and WPS to install and maintain EV charging equipment for customers at their homes or businesses. The programs provide direct benefits to customers by removing cost barriers associated with installing EV equipment. In October 2021, subject to the receipt of any necessary regulatory approvals, we pledged to expand the EV charging network within the service territories of our electric utilities. In doing so, we joined a coalition of utility companies in a unified effort to make EV charging convenient and widely available throughout the Midwest. The coalition we joined is planning to help build and grow EV charging corridors, enabling the general public to safely and efficiently charge their vehicles.

We also continue to reduce methane emissions by improving our natural gas distribution system. We set a target across our natural gas distribution operations to achieve net-zero methane emissions by the end of 2030. We plan to achieve our net-zero goal through an effort that includes both continuous operational improvements and equipment upgrades, as well as the use of RNG throughout our natural gas utility systems. In 2022, we received approval from the PSCW for our RNG pilots. We have since signed contracts for RNG for our natural gas distribution business in Wisconsin, which will be transporting the output of local dairy farms onto our gas distribution systems. The RNG supplied will directly replace higher-emission methane from natural gas that would have entered our pipes. These contracts bring us to 1.8 Bcf of RNG planned to enter our systems. RNG began flowing in 2023.

In December 2023, we started a pilot program with Electric Power Research Institute and CMBlu Energy, a Germany-based designer and manufacturer, to test a new form of long-duration energy storage on the U.S. electric grid. The program will test battery system performance, including the ability to store and discharge energy for up to twice as long as the typical lithium-ion batteries in use today. We expect the full pilot to be completed in 2024.

Reliability

We have made significant reliability-related investments in recent years, and in accordance with our ESG Progress Plan, expect to continue strengthening and modernizing our generation fleet, as well as our electric and natural gas distribution networks to further improve reliability.

Below are a few examples of reliability projects that are proposed, currently underway, or recently completed.

- Included in the capital plan are additional proposed LNG storage facilities providing approximately four Bcf of natural gas supply, which is needed to ensure gas supply for winter reliability.

- WE and WG have received approval to each construct their own LNG facility to meet anticipated peak demand. Each facility would provide approximately one Bcf of natural gas supply to meet anticipated peak demand without requiring the construction of additional interstate pipeline capacity. The WE LNG facility was commercially operational at the end of 2023 and the WG LNG facility is targeted for 2024.

- Through the SMP, PGL had been working to replace old iron pipes and facilities in Chicago's natural gas delivery system with modern polyethylene pipes to reinforce the long-term safety and reliability of the system. In November 2023, the ICC ordered

PGL to pause spending on the SMP until the ICC completes a proceeding to determine the optimal method for replacing aging natural gas infrastructure and a prudent investment level. The ICC initiated the proceeding on January 31, 2024, and the proceeding is expected to last 12 months. For more information, see Factors Affecting Results, Liquidity, and Capital Resources - Regulatory, Legislative, and Legal Matters - Future Illinois Proceedings.

On January 3, 2024, the ICC granted PGL a limited-scope rehearing, which is limited to the authorized spending for the completion of SMP projects that started in 2023 and the authorized spending for emergency repairs needed to ensure the safety and reliability of PGL's delivery system. As a result, PGL has suspended neighborhood work, pending the results of the limited rehearing. See Note 26, Regulatory Environment, for more information.

- Our utilities continue to upgrade their electric and natural gas distribution systems to enhance reliability and storm hardening.

We expect to spend approximately $3.8 billion from 2024 to 2028 on reliability related projects with continued investment over the next decade. For more details, see Liquidity and Capital Resources – Cash Requirements – Significant Capital Projects.

Operating Efficiency

We continually look for ways to optimize the operating efficiency of our company and will continue to do so under the ESG Progress Plan. For example, we are making progress on our AMI program, replacing aging meter-reading equipment on both our network and customer property. An integrated system of smart meters, communication networks, and data management programs enables two-way communication between our utilities and our customers. This program reduces the manual effort for disconnects and reconnects and enhances outage management capabilities.

We continue to focus on integrating the resources of all our businesses and finding the best and most efficient processes.

Financial Discipline

A strong adherence to financial discipline is essential to meeting our earnings projections and maintaining a strong balance sheet, stable cash flows, a growing dividend, and quality credit ratings.

We follow an asset management strategy that focuses on investing in and acquiring assets consistent with our strategic plans, as well as disposing of assets, including property, plants, equipment, and entire business units, that are no longer strategic to operations, are not performing as intended, or have an unacceptable risk profile. See Note 3, Dispositions, for information on recent transactions.

Our planned investment focus from 2024 to 2028 is in our regulated utilities and non-utility energy infrastructure business, as well as our investment in ATC. We expect total capital expenditures for our regulated utility businesses to be approximately $19.5 billion from 2024 to 2028. In addition, we currently forecast that our share of ATC's projected capital expenditures over the next five years will be approximately $3 billion. We expect to invest approximately $1.2 billion in our non-utility energy infrastructure business over the same period, which includes our previously announced investment in Maple Flats and the purchase of an additional 10% ownership interest in Samson I. Specific projects included in the $23.7 billion ESG Progress Plan are discussed in more detail below under Liquidity and Capital Resources – Cash Requirements – Significant Capital Projects. Also, see Note 2, Acquisitions, for information on recent and pending transactions.

Exceptional Customer Care

Our approach is driven by an intense focus on delivering exceptional customer care every day. We strive to provide the best value for our customers by demonstrating personal responsibility for results, leveraging our capabilities and expertise, and using creative solutions to meet or exceed our customers' expectations.

A multiyear effort is driving a standardized, seamless approach to digital customer service across our companies. We have moved all utilities to a common platform for all customer-facing self-service options. Using common systems and processes reduces costs, provides greater flexibility and enhances the consistent delivery of exceptional service to customers.

Safety

Safety is one of our core values and a critical component of our culture. We are committed to keeping our employees and the public safe through a comprehensive corporate safety program that focuses on employee engagement and elimination of at-risk behaviors.

Under our "Target Zero" mission, we have an ultimate goal of zero incidents, accidents, and injuries. Management and union leadership work together to reinforce the Target Zero culture. We set annual goals for safety results as well as measurable leading indicators, in order to raise awareness of at-risk behaviors and situations and guide injury-prevention activities. All employees are encouraged to report unsafe conditions or incidents that could have led to an injury. Injuries and tasks with high levels of risk are assessed, and findings and best practices are shared across our companies.

Our corporate safety program provides a forum for addressing employee concerns, training employees and contractors on current safety standards, and recognizing those who demonstrate a safety focus.

RESULTS OF OPERATIONS

The following discussion and analysis of our Results of Operations includes comparisons of our results for the year ended December 31, 2023 with the year ended December 31, 2022. For a similar discussion that compares our results for the year ended December 31, 2022 with the year ended December 31, 2021, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations in Part II of our 2022 Annual Report on Form 10-K, which was filed with the SEC on February 23, 2023.

Consolidated Earnings

The following table compares our consolidated results for the year ended December 31, 2023 with the year ended December 31, 2022, including favorable or better, "B," and unfavorable or worse, "W," variances:

	Year Ended December 31		
(in millions, except per share data)	**2023**	**2022**	**B (W)**
Wisconsin	**$ 851.3**	$ 758.4	$ 92.9
Illinois	**140.0**	226.9	(86.9)
Other states	**48.1**	39.7	8.4
Electric transmission	**119.1**	129.5	(10.4)
Non-utility energy infrastructure	**336.0**	324.4	11.6
Corporate and other	**(162.8)**	(70.8)	(92.0)
Net income attributed to common shareholders	**$ 1,331.7**	$ 1,408.1	$ (76.4)
Diluted earnings per share	**$ 4.22**	$ 4.45	$ (0.23)

Earnings decreased $76.4 million during 2023, compared with 2022. The significant factors impacting the $76.4 million decrease in earnings were:

- A $92.0 million increase in the net loss attributed to common shareholders at the corporate and other segment, driven by higher interest expense on both long-term and short-term debt. This negative impact was partially offset by net gains from the investments held in the Integrys rabbi trust during 2023, compared with net losses during the same period in 2022. The gains and losses from the investments held in the rabbi trust partially offset the changes in benefit costs related to deferred compensation, which are primarily included in other operation and maintenance expense in our utility segments. See Note 17, Fair Value Measurements, for more information on our investments held in the Integrys rabbi trust.

- An $86.9 million decrease in net income attributed to common shareholders at the Illinois segment, driven by higher operating expenses, primarily due to an impairment associated with the ICC's disallowance of certain incurred capital costs in its November 2023 rate orders for PGL and NSG, and the year-over-year impact of a gain recorded in 2022 on the sale of certain real estate by PGL. Partially offsetting these increases in operating expenses were lower natural gas distribution and maintenance costs and a decrease in expenses related to charitable contributions. Higher natural gas margins, due to a positive impact from PGL's rate order, effective December 1, 2023, and continued capital investment in the SMP project in 2023 under PGL's QIP rider, also partially offset the net increase in operating expenses. See Note 26, Regulatory Environment, for more information on the PGL and NSG rate orders.

- A $10.4 million decrease in net income attributed to common shareholders at the electric transmission segment, driven by the positive impact in 2022 related to the D.C. Circuit Court of Appeals opinion issued in August 2022 addressing complaints related to ATC's ROE. For information on this D.C. Circuit Court of Appeals opinion, see Factors Affecting Results, Liquidity, and Capital Resources – Regulatory, Legislative, and Legal Matters – American Transmission Company Allowed Return on Equity Complaints.

These decreases in earnings were partially offset by:

- A $92.9 million increase in net income attributed to common shareholders at the Wisconsin segment, driven by an increase in electric and natural gas margins related to the impact of the Wisconsin rate orders approved by the PSCW, effective January 1, 2023, and a positive year-over-year impact from collections of fuel and purchased power costs. These positive impacts were partially offset by a decrease in electric and natural gas margins due to lower sales volumes, and higher operating expenses, including increases in expenses related to transmission, depreciation and amortization, and regulatory amortizations.

- An $11.6 million increase in net income attributed to common shareholders at the non-utility energy infrastructure segment, primarily due to an increase in PTCs driven by the acquisition of additional renewable generation facilities in the second half of 2022 and the first quarter of 2023, partially offset by higher interest expense.

- An $8.4 million increase in net income attributed to common shareholders at the other states segment, driven by higher natural gas margins due to an interim rate increase at MERC, effective January 1, 2023. See Note 26, Regulatory Environment, for more information. This positive impact was partially offset by a decrease in natural gas margins due to lower sales volumes and increases in depreciation and amortization and interest expense.

Non-GAAP Financial Measures

The discussions below address the contribution of each of our segments to net income attributed to common shareholders. The discussions include financial information prepared in accordance with GAAP, as well as electric margins and natural gas margins, which are not measures of financial performance under GAAP. Electric margins (electric revenues less fuel and purchased power costs) and natural gas margins (natural gas revenues less cost of natural gas sold) are non-GAAP financial measures because they exclude other operation and maintenance expense, depreciation and amortization, and property and revenue taxes.

We believe that electric and natural gas margins provide a useful basis for evaluating utility operations since the majority of prudently incurred fuel and purchased power costs, as well as prudently incurred natural gas costs, are passed through to customers in current rates. As a result, management uses electric and natural gas margins internally when assessing the operating performance of our segments as these measures exclude the majority of revenue fluctuations caused by changes in these expenses. Similarly, the presentation of electric and natural gas margins herein is intended to provide supplemental information for investors regarding our operating performance.

Our electric margins and natural gas margins may not be comparable to similar measures presented by other companies. Furthermore, these measures are not intended to replace operating income as determined in accordance with GAAP as an indicator of operating performance. The following table shows operating income by segment for our utility operations during years ended December 31, 2023 and 2022:

	Year Ended December 31	
(in millions)	**2023**	**2022**
Wisconsin	**$ 1,553.3**	$ 1,463.1
Illinois	**270.8**	369.7
Other states	**79.7**	64.2

Each applicable segment discussion below includes a table that provides the calculation of electric margins and natural gas margins, as applicable, along with a reconciliation to the most directly comparable GAAP measure, operating income.

Wisconsin Segment Contribution to Net Income Attributed to Common Shareholders

The Wisconsin segment's contribution to net income attributed to common shareholders for the year ended December 31, 2023 was $851.3 million, representing a $92.9 million, or 12.2%, increase over the prior year. The higher earnings were driven by an increase in electric and natural gas margins related to the impact of the Wisconsin rate orders approved by the PSCW, effective January 1, 2023, and a positive year-over-year impact from collections of fuel and purchased power costs. These positive impacts were partially offset by a decrease in electric and natural gas margins due to lower sales volumes, and higher operating expenses, including increases in expenses related to transmission, depreciation and amortization, and regulatory amortizations.

	Year Ended December 31		
(in millions)	**2023**	**2022**	**B (W)**
Electric revenues	**$ 5,010.8**	$ 4,971.8	$ 39.0
Fuel and purchased power	**1,615.9**	1,881.4	265.5
Total electric margins	**3,394.9**	3,090.4	304.5
Natural gas revenues	**1,615.1**	1,988.7	(373.6)
Cost of natural gas sold	**894.7**	1,327.4	432.7
Total natural gas margins	**720.4**	661.3	59.1
Total electric and natural gas margins	**4,115.3**	3,751.7	363.6
Other operation and maintenance	**1,531.3**	1,351.3	(180.0)
Depreciation and amortization	**851.5**	754.7	(96.8)
Property and revenue taxes	**179.2**	182.6	3.4
Operating income	**1,553.3**	1,463.1	90.2
Other income, net	**137.6**	99.9	37.7
Interest expense	**601.0**	555.9	(45.1)
Income before income taxes	**1,089.9**	1,007.1	82.8
Income tax expense	**237.4**	247.5	10.1
Preferred stock dividends of subsidiary	**1.2**	1.2	—
Net income attributed to common shareholders	**$ 851.3**	$ 758.4	$ 92.9

The following table shows a breakdown of other operation and maintenance:

(in millions)	Year Ended December 31 2023	2022	B (W)
Operation and maintenance not included in line items below	**$ 635.1**	$ 655.8	$ 20.7
Transmission [1]	**540.4**	430.9	(109.5)
Regulatory amortizations and other pass through expenses [2]	**208.2**	145.5	(62.7)
We Power [3]	**141.4**	108.1	(33.3)
Earnings sharing mechanisms [4]	**5.6**	(13.5)	(19.1)
Other	**0.6**	24.5	23.9
Total other operation and maintenance	**$ 1,531.3**	$ 1,351.3	$ (180.0)

[1] Represents transmission expense that our electric utilities are authorized to collect in rates. The PSCW has approved escrow accounting for ATC and MISO network transmission expenses for WE and WPS. As a result, WE and WPS defer as a regulatory asset or liability, the difference between actual transmission costs and those included in rates until recovery or refund is authorized in a future rate proceeding. During 2023 and 2022, $520.4 million and $516.7 million, respectively, of costs were billed to our electric utilities by transmission providers.

During 2022, WE and WPS amortized $81.0 million of the regulatory liabilities associated with their transmission escrows to offset certain 2022 revenue deficiencies, as approved by the PSCW in order to forego filing for 2022 base rate increases. This amortization drove the lower transmission expense during 2022.

[2] Regulatory amortizations and other pass through expenses are substantially offset in margins and therefore do not have a significant impact on net income. Effective January 1, 2023, the PSCW approved escrow accounting for pension and OPEB costs, as well as certain costs associated

with our jointly-owned Columbia plant. As a result, our Wisconsin utilities defer as a regulatory asset or liability, the difference between these actual costs and those included in rates until recovery or refund is authorized in a future rate proceeding.

(3) Represents costs associated with the We Power generation units, including operating and maintenance costs recognized by WE. During 2023 and 2022, $124.5 million and $121.7 million, respectively, of costs were billed to or incurred by WE related to the We Power generation units, with the difference in costs billed or incurred and expenses recognized, either deferred or deducted from the regulatory asset.

(4) Represents operation and maintenance associated with the earnings mechanisms we have in place. In 2022, this amount was reduced by the $21.6 million amortization of certain regulatory liability balances associated with WPS's 2020 earnings sharing mechanism to offset certain 2022 revenue deficiencies, as approved by the PSCW in order to forego filing for 2022 base rate increases. See Note 26, Regulatory Environment, for more information.

The following tables provide information on delivered sales volumes by customer class and weather statistics:

	Year Ended December 31		
Electric Sales Volumes (MWh - in thousands)	**2023**	**2022**	**B (W)**
Customer class			
Residential	**10,966.8**	11,372.6	(405.8)
Small commercial and industrial [1]	**12,729.9**	12,867.1	(137.2)
Large commercial and industrial [1]	**11,992.8**	12,181.6	(188.8)
Other	**128.6**	139.0	(10.4)
Total retail [1]	**35,818.1**	36,560.3	(742.2)
Wholesale	**1,821.8**	2,444.7	(622.9)
Resale	**6,015.5**	3,962.8	2,052.7
Total sales in MWh [1]	**43,655.4**	42,967.8	687.6

(1) Includes distribution sales for customers who have purchased power from an alternative electric supplier in Michigan.

	Year Ended December 31		
Natural Gas Sales Volumes (Therms - in millions)	**2023**	**2022**	**B (W)**
Customer class			
Residential	**1,014.8**	1,189.6	(174.8)
Commercial and industrial	**660.1**	746.6	(86.5)
Total retail	**1,674.9**	1,936.2	(261.3)
Transportation	**1,321.6**	1,438.1	(116.5)
Total sales in therms	**2,996.5**	3,374.3	(377.8)

	Year Ended December 31		
Weather (Degree Days)	**2023**	**2022**	**B (W)**
WE and WG [(1)]			
Heating (6,509 Normal)	**5,409**	6,369	(15.1)%
Cooling (775 Normal)	**876**	944	(7.2)%
WPS [(2)]			
Heating (7,354 Normal)	**6,544**	7,387	(11.4)%
Cooling (544 Normal)	**596**	718	(17.0)%
UMERC [(3)]			
Heating (8,392 Normal)	**7,539**	8,643	(12.8)%
Cooling (342 Normal)	**315**	358	(12.0)%

(1) Normal degree days are based on a 20-year moving average of monthly temperatures from Mitchell International Airport in Milwaukee, Wisconsin.

(2) Normal degree days are based on a 20-year moving average of monthly temperatures from the Green Bay, Wisconsin weather station.

(3) Normal degree days are based on a 20-year moving average of monthly temperatures from the Iron Mountain, Michigan weather station.

Electric Revenues

Electric revenues increased $39.0 million during 2023, compared with 2022. To the extent that changes in fuel and purchased power costs are passed through to customers, the changes are offset by comparable changes in revenues. See the discussion of electric utility margins below for more information related to the recovery of fuel and purchased power costs and the remaining drivers of the changes in electric revenues.

Electric Utility Margins

Electric utility margins at the Wisconsin segment increased $304.5 million during 2023, compared with 2022. The significant factors impacting the higher electric utility margins were:

- A $330.5 million increase in margins related to the impact of the Wisconsin rate orders approved by the PSCW, effective January 1, 2023.

- A $61.6 million year-over-year positive impact from collections of fuel and purchased power costs. Under the Wisconsin fuel rules, the margins of our electric utilities are impacted by under- or over-collections of certain fuel and purchased power costs that are within a 2% price variance from the costs included in rates, and the remaining variance beyond the 2% price variance is generally deferred for future recovery or refund to customers. In 2022, WPS was unable to defer a portion of its under-collected fuel and purchased power costs due to earning an ROE in excess of the PSCW authorized amount.

- A $15.7 million increase in margins during 2023, related to the expiration of a capacity purchase contract driven by the acquisition of the Whitewater facility, effective January 1, 2023.

These increases in margins were partially offset by:

- A $67.9 million decrease in margins related to lower retail electric sales volumes, including steam operations, driven by the impact of unfavorable weather during 2023, compared with 2022. As measured by cooling degree days, 2023 was 7.2% and 17.0% cooler than 2022 in the Milwaukee area and Green Bay area, respectively. As measured by heating degree days, 2023 was 15.1% and 11.4% warmer than 2022 in the Milwaukee area and Green Bay area, respectively.

- A $25.1 million decrease in other revenues, primarily related to a FERC order in January 2023 that eliminated reactive power compensation MISO was required to pay to generators, including our electric utilities, as well as lower revenues from third-party use of our assets. The decrease in reactive power revenues is substantially offset by a decrease in transmission expense related to a deferral of these revenues as a component of our transmission escrow, as approved by the PSCW in June 2023 and discussed below.

- Lower margins of $8.0 million driven by the expiration of a wholesale contract in May 2022.

Natural Gas Revenues

Natural gas revenues decreased $373.6 million during 2023, compared with 2022. Because prudently incurred natural gas costs are passed through to our customers in current rates, the changes are offset by comparable changes in revenues. The average per-unit cost of natural gas decreased approximately 25% during 2023, compared with 2022. The remaining drivers of changes in natural gas revenues are described in the discussion of natural gas utility margins below.

Natural Gas Utility Margins

Natural gas utility margins at the Wisconsin segment increased $59.1 million during 2023, compared with 2022. The most significant factor impacting the higher natural gas utility margins was a $116.6 million increase in margins related to the impact of the Wisconsin rate orders approved by the PSCW, effective January 1, 2023. This increase in margins was partially offset by a $57.4 million decrease in margins from lower sales volumes, driven by the impact of unfavorable weather during 2023, compared with 2022.

Other Operating Expenses (includes other operation and maintenance, depreciation and amortization, and property and revenue taxes)

Other operating expenses at the Wisconsin segment increased $273.4 million during 2023, compared with 2022. The significant factors impacting the increase in other operating expenses were:

- A $109.5 million increase in transmission expense as approved in the PSCW's 2023 rate orders, effective January 1, 2023. See the notes under the other operation and maintenance table above for more information. This amount is net of a deferral of $11.9 million approved by the PSCW in June 2023, retroactive to December 1, 2022, in response to a FERC order eliminating reactive power compensation to our utilities, as discussed in electric margins above.

- A $96.8 million increase in depreciation and amortization, driven by assets being placed into service as we continue to execute on our capital plan.

- A $62.7 million increase in regulatory amortizations and other pass through expenses, as discussed in the notes under the other operation and maintenance table above.

- A $33.3 million increase in other operation and maintenance expense related to the We Power leases, as discussed in the notes under the other operation and maintenance table above.

- A $29.4 million increase in other operating and maintenance related to our power plants, driven by increases to certain plant-related regulatory assets in 2022 as a result of the December 2022 Wisconsin rate orders as well as operating costs associated with Whitewater, which we purchased in January 2023. These increases were partially offset by lower severance during 2023.

- A $19.1 million increase in expense related to the earnings sharing mechanisms in place at our Wisconsin utilities, as discussed in the notes under the other operation and maintenance table above. See Note 26, Regulatory Environment, for more information.

These increases in other operating expenses were partially offset by:

- A $23.9 million decrease in expense primarily related to lower commitments made in 2023 to fund our charitable foundations.

- A $19.1 million increase in pre-tax gains on the sale of land, primarily at the site of our former Pleasant Prairie power plant during 2023.

- A $15.6 million decrease in electric and natural gas distribution expenses, driven by lower costs to maintain the distribution system and for storm restoration during 2023, compared with 2022.

- A $7.0 million decrease in expenses associated with the settlement of legal claims.

Other Income, Net

Other income, net at the Wisconsin segment increased $37.7 million during 2023, compared with 2022, driven by higher AFUDC-Equity due to continued capital investment. See Note 27, Other Income, Net, for more information.

Interest Expense

Interest expense at the Wisconsin segment increased $45.1 million during 2023, compared with 2022. The increase was primarily due to the impact of WE and WPS issuing long-term debt during the third and fourth quarters of 2022, respectively, and higher average short-term debt balances and increased short-term debt interest rates. Also contributing to the increase was the 2022 deferral of $8.2 million of interest expense related to capital investments made by WG since its 2020 rate case, as approved by the PSCW in an order that allowed our Wisconsin utilities to offset certain 2022 revenue deficiencies in order to forego filing for 2022 base rate increases. This deferred interest expense is now being amortized over a two-year period. During 2023, WG amortized $4.1 million of interest expense. See Note 26, Regulatory Environment, for more information. These increases were partially offset by higher AFUDC-Debt due to continued capital investment and lower interest expense on finance lease liabilities, primarily related to the We Power leases, as finance lease liabilities decrease each year as payments are made.

Income Tax Expense

Income tax expense at the Wisconsin segment decreased $10.1 million during 2023, compared with 2022. The decrease was primarily due to a $23.1 million increase in PTCs and a $6.3 million increase in income tax benefits associated with AFUDC-Equity, both driven by continued capital investment. These decreases in income tax expense were partially offset by higher pre-tax income. See Note 16, Income Taxes, for more information.

Illinois Segment Contribution to Net Income Attributed to Common Shareholders

The Illinois segment's contribution to net income attributed to common shareholders for the year ended December 31, 2023 was $140.0 million, representing an $86.9 million, or 38.3%, decrease from the prior year. The decrease was driven by higher operating expenses, primarily due to an impairment associated with the ICC's disallowance of certain incurred capital costs in its November 2023 rate orders for PGL and NSG, and the year-over-year impact of a gain recorded in 2022 on the sale of certain real estate by PGL. Partially offsetting these increases in operating expenses were lower natural gas distribution and maintenance costs and a decrease in expenses related to charitable contributions. Higher natural gas margins, due to a positive impact from PGL's rate order, effective December 1, 2023, and continued capital investment in the SMP project in 2023 under PGL's QIP rider, also partially offset the net increase in operating expenses. See Note 26, Regulatory Environment, for more information on the PGL and NSG rate orders.

Since the majority of PGL and NSG customers use natural gas for heating, net income attributed to common shareholders at the Illinois segment is sensitive to weather and is generally higher during the winter months.

(in millions)	Year Ended December 31 2023	2022	B (W)
Natural gas revenues	**$ 1,557.8**	$ 1,890.9	$ (333.1)
Cost of natural gas sold	**443.0**	792.5	349.5
Total natural gas margins	**1,114.8**	1,098.4	16.4
Other operation and maintenance	**397.9**	459.2	61.3
Impairment related to ICC disallowances	**178.9**	—	(178.9)
Depreciation and amortization	**237.3**	230.9	(6.4)
Property and revenue taxes	**29.9**	38.6	8.7
Operating income	**270.8**	369.7	(98.9)
Other income, net	**6.7**	14.1	(7.4)
Interest expense	**88.9**	73.8	(15.1)
Income before income taxes	**188.6**	310.0	(121.4)
Income tax expense	**48.6**	83.1	34.5
Net income attributed to common shareholders	**$ 140.0**	$ 226.9	$ (86.9)

The following table shows a breakdown of other operation and maintenance:

(in millions)	Year Ended December 31 2023	2022	B (W)
Operation and maintenance not included in the line items below	**$ 303.4**	$ 319.4	$ 16.0
Riders [(1)]	**94.3**	127.2	32.9
Regulatory amortizations [(1)]	**0.2**	(2.4)	(2.6)
Other	**—**	15.0	15.0
Total other operation and maintenance	**$ 397.9**	$ 459.2	$ 61.3

(1) These riders and regulatory amortizations are substantially offset in margins and therefore do not have a significant impact on net income.

The following tables provide information on delivered sales volumes by customer class and weather statistics:

Natural Gas Sales Volumes (Therms - in millions)	Year Ended December 31		
	2023	**2022**	**B (W)**
Customer Class			
Residential	**778.1**	907.0	(128.9)
Commercial and industrial	**305.2**	353.7	(48.5)
Total retail	**1,083.3**	1,260.7	(177.4)
Transportation	**740.4**	839.5	(99.1)
Total sales in therms	**1,823.7**	2,100.2	(276.5)

Weather (Degree Days) [(1)]	Year Ended December 31		
	2023	**2022**	**B (W)**
Heating (6,005 Normal)	**5,097**	6,140	(17.0)%

(1) Normal heating degree days are based on a 12-year moving average of monthly temperatures from Chicago's O'Hare Airport.

Natural Gas Revenues

Natural gas revenues decreased $333.1 million during 2023, compared with 2022. Because prudently incurred natural gas costs are passed through to our customers in current rates, the changes are offset by comparable changes in revenues. The average per-unit cost of natural gas sold decreased approximately 35% during 2023, compared with 2022. The remaining drivers of changes in natural gas revenues are described in the discussion of margins below.

Natural Gas Utility Margins

Natural gas utility margins at the Illinois segment, net of the $32.9 million impact of the riders referenced in the table above, increased $49.3 million during 2023, compared with 2022. The increase in margins was primarily driven by:

- A $29.5 million increase in margins related to the impact of the PGL rate order issued by the ICC, effective December 1, 2023.

- A $23.9 million increase in revenues at PGL due to continued capital investment in the SMP project under the QIP rider. PGL recovered the costs related to the SMP through a surcharge on customer bills pursuant to the QIP rider, which was in effect for most of 2023.

For information on PGL's rate order, the QIP rider, PGL's plan to recover SMP costs after 2023, and the pause in spending on the SMP, see Note 26, Regulatory Environment.

Other Operating Expenses (includes other operation and maintenance, impairment related to ICC disallowances, depreciation and amortization, and property and revenue taxes)

Other operating expenses at the Illinois segment increased $148.2 million, net of the $32.9 million impact of the riders referenced in the table above, during 2023, compared with 2022. The significant factors impacting the increase in other operating expenses were:

- A $178.9 million impairment associated with the ICC orders received in November 2023 related to PGL's and NSG's rate reviews, which included the disallowance of previously incurred capital costs at PGL and NSG, in the amount of $177.2 million and $1.7 million, respectively. See Note 26, Regulatory Environment, for more information on the ICC disallowances.

- A $54.5 million pre-tax gain on the sale of certain real estate in Chicago during 2022. See Note 3, Dispositions, for more information.

- An $11.1 million increase in expense driven by an ICC order received in May 2023 related to an annual prudency review of PGL's and NSG's UEA riders, which required refunds to ratepayers starting in September 2023. See Factors Affecting Results, Liquidity, and Capital Resources – Regulatory, Legislative, and Legal Matters – Regulatory Recovery for more information.

These increases in operating expenses were partially offset by:

- A $43.8 million decrease in natural gas distribution and maintenance costs, primarily related to maintaining the natural gas infrastructure during 2023, compared with 2022.
- A $25.0 million decrease in expenses related to contributions to charitable projects supporting our customers and the communities within our service territories during 2023, compared with 2022.
- A $9.4 million decrease in expenses associated with the settlement of legal claims during 2022.
- An $8.7 million decrease in property and revenue taxes, primarily driven by lower property and use taxes.
- A $3.7 million decrease in customer service expense due to lower call center expense and metering costs.
- A $3.0 million decrease in benefit costs, primarily due to lower stock-based compensation expense related to plan performance during 2023.

Other Income, Net

Other income, net at the Illinois segment decreased $7.4 million during 2023, compared with 2022, driven by lower net credits from the non-service components of our net periodic pension and OPEB costs. See Note 20, Employee Benefits, for more information on our benefit costs.

Interest Expense

Interest expense at the Illinois segment increased $15.1 million during 2023, compared with 2022, driven by higher long-term debt balances related to incremental borrowings in both 2023 and 2022, primarily related to additional capital investment. Also contributing to the increase was higher short-term debt interest rates.

Income Tax Expense

Income tax expense at the Illinois segment decreased $34.5 million during 2023, compared with 2022, driven by a decrease in pre-tax income.

Other States Segment Contribution to Net Income Attributed to Common Shareholders

The other states segment's contribution to net income attributed to common shareholders for the year ended December 31, 2023 was $48.1 million, representing an $8.4 million, or 21.2%, increase over the prior year. The increase was driven by higher natural gas margins due to an interim rate increase at MERC, effective January 1, 2023. See Note 26, Regulatory Environment, for more information. This positive impact was partially offset by a decrease in natural gas margins due to lower sales volumes and increases in depreciation and amortization and interest expense.

Since the majority of MERC and MGU customers use natural gas for heating, net income attributed to common shareholders is sensitive to weather and is generally higher during the winter months.

	Year Ended December 31		
(in millions)	**2023**	**2022**	**B (W)**
Natural gas revenues	**$ 519.1**	$ 618.5	$ (99.4)
Cost of natural gas sold	**277.2**	391.6	114.4
Total natural gas margins	**241.9**	226.9	15.0
Other operation and maintenance	**94.5**	98.5	4.0
Depreciation and amortization	**43.3**	40.9	(2.4)
Property and revenue taxes	**24.4**	23.3	(1.1)
Operating income	**79.7**	64.2	15.5
Other income, net	**0.6**	2.5	(1.9)
Interest expense	**15.9**	13.9	(2.0)
Income before income taxes	**64.4**	52.8	11.6
Income tax expense	**16.3**	13.1	(3.2)
Net income attributed to common shareholders	**$ 48.1**	$ 39.7	$ 8.4

The following table shows a breakdown of other operation and maintenance:

	Year Ended December 31		
(in millions)	**2023**	**2022**	**B (W)**
Operation and maintenance not included in line item below	**$ 72.6**	$ 77.8	$ 5.2
Regulatory amortizations and other pass through expenses [1]	**21.9**	20.7	(1.2)
Total other operation and maintenance	**$ 94.5**	$ 98.5	$ 4.0

[1] Regulatory amortizations and other pass through expenses are substantially offset in margins and therefore do not have a significant impact on net income.

The following tables provide information on delivered sales volumes by customer class and weather statistics:

Natural Gas Sales Volumes (Therms - in millions)	Year Ended December 31		
	2023	**2022**	**B (W)**
Customer Class			
Residential	**293.8**	353.1	(59.3)
Commercial and industrial	**196.5**	227.6	(31.1)
Total retail	**490.3**	580.7	(90.4)
Transportation	**799.6**	794.8	4.8
Total sales in therms	**1,289.9**	1,375.5	(85.6)

Weather (Degree Days) [1]	Year Ended December 31		
	2023	**2022**	**B (W)**
MERC			
Heating (7,973 Normal)	**7,324**	8,585	(14.7)%
MGU			
Heating (6,214 Normal)	**5,456**	6,277	(13.1)%

[1] Normal heating degree days for MERC and MGU are based on a 20-year moving average and 15-year moving average, respectively, of monthly temperatures from various weather stations throughout their respective territories.

Natural Gas Revenues

Natural gas revenues decreased $99.4 million during 2023, compared with 2022. Because prudently incurred natural gas costs are passed through to our customers in current rates, the changes are offset by comparable changes in revenues. The average per-unit cost of natural gas sold decreased approximately 17% during 2023, compared with 2022. The remaining drivers of changes in natural gas revenues are described in the discussion of margins below.

Natural Gas Utility Margins

Natural gas utility margins increased $15.0 million during 2023, compared with 2022, driven by a $19.5 million increase related to an interim rate increase at MERC that was effective January 1, 2023. See Note 26, Regulatory Environment, for more information. This increase in natural gas utility margins was partially offset by a $6.1 million decrease related to lower sales volumes, primarily driven by warmer weather. As measured by heating degree days, 2023 was 14.7% and 13.1% warmer than 2022 at MERC and MGU, respectively.

Other Operating Expenses (includes other operation and maintenance, depreciation and amortization, and property and revenue taxes)

Other operating expenses at the other states segment decreased $0.5 million during 2023, compared with 2022. The significant factors impacting the decrease in operating expenses were:

- A $1.8 million decrease in natural gas operations and customer service expense, driven by fewer operation and maintenance projects at MGU during 2023.

- A $1.6 million decrease in benefit costs, primarily due to lower stock-based compensation expense related to plan performance.

These decreases in other operating expenses were partially offset by a $2.4 million increase in depreciation and amortization related to continued capital investment.

Other Income, Net

Other income, net at the other states segment decreased $1.9 million during 2023, compared with 2022, driven by lower net credits from the non-service components of our net periodic pension and OPEB costs. See Note 20, Employee Benefits, for more information on our benefit costs.

Interest Expense

Interest expense at the other states segment increased $2.0 million during 2023, compared with 2022, primarily due to higher short-term debt interest rates.

Income Tax Expense

Income tax expense at the other states segment increased $3.2 million during 2023, compared with 2022, driven by an increase in pre-tax income.

Electric Transmission Segment Contribution to Net Income Attributed to Common Shareholders

	Year Ended December 31		
(in millions)	**2023**	**2022**	**B (W)**
Equity in earnings of transmission affiliates	**$ 177.5**	$ 194.7	$ (17.2)
Interest expense	**19.4**	19.4	—
Income before income taxes	**158.1**	175.3	(17.2)
Income tax expense	**39.0**	45.8	6.8
Net income attributed to common shareholders	**$ 119.1**	$ 129.5	$ (10.4)

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Equity in Earnings of Transmission Affiliates

Equity in earnings of transmission affiliates decreased $17.2 million during 2023, compared with 2022. The decrease was primarily driven by the $20.5 million positive impact recorded in 2022 related to the D.C. Circuit Court of Appeals opinion issued in August 2022 addressing complaints related to ATC's ROE. For information on this D.C. Circuit Court of Appeals opinion, see Factors Affecting Results, Liquidity, and Capital Resources – Regulatory, Legislative, and Legal Matters – American Transmission Company Allowed Return on Equity Complaints. Partially offsetting this negative year-over-year impact was continued capital investment by ATC.

Income Tax Expense

Income tax expense at the electric transmission segment decreased $6.8 million during 2023, compared with 2022, driven by a decrease in pre-tax income.

Non-Utility Energy Infrastructure Segment Contribution to Net Income Attributed to Common Shareholders

	Year Ended December 31		
(in millions)	**2023**	**2022**	**B (W)**
Operating income	**$ 360.7**	$ 372.8	$ (12.1)
Interest expense	**94.3**	68.9	(25.4)
Income before income taxes	**266.4**	303.9	(37.5)
Income tax benefit	**(68.4)**	(20.9)	47.5
Net (income) loss attributed to noncontrolling interests	**1.2**	(0.4)	1.6
Net income attributed to common shareholders	**$ 336.0**	$ 324.4	$ 11.6

Operating Income

Operating income at the non-utility energy infrastructure segment decreased $12.1 million during 2023, compared with 2022, driven by these items at WECI:

- Recognition of $15.2 million in revenue related to our Upstream wind park in 2022 that was associated with market settlements received from SPP in February 2021. These settlements were subject to a FERC complaint, so we were not able to recognize them as revenue until the FERC issued an order denying that complaint in 2022.

- A $13.4 million positive revenue impact in 2022 from a sharing arrangement with one of our Blooming Grove customers resulting from strong energy prices.

These decreases in operating income were partially offset by:

- Recognition of $6.4 million in revenue related to our Blooming Grove wind park in 2023 for a capacity payment received from PJM Interconnection that was associated with a December 2022 cold weather event. The capacity payment was subject to a FERC complaint, so we recognized this as revenue in 2023 when FERC issued an order denying that complaint.

- A $4.4 million positive impact from Sapphire Sky Wind, a new wind facility acquired in February 2023.

In addition to the above items at WECI, there was a $5.4 million positive impact from We Power due to continued capital investment.

Interest Expense

Interest expense at the non-utility energy infrastructure segment increased $25.4 million during 2023, compared with 2022, driven by a $16.1 million increase in interest expense due to WECI’s issuance of a $430.0 million long-term intercompany note payable to WEC Energy Group in April 2023. This intercompany interest expense is offset by higher intercompany interest income at the corporate and other segment and is eliminated in consolidation. Also driving the increase was the impact of WECI Wind Holding II's issuance of long-term debt in December 2022.

Income Tax Benefit

The income tax benefit at the non-utility energy infrastructure segment increased $47.5 million during 2023, compared with 2022. The increase was primarily due to a $37.5 million increase in PTCs in 2023, driven by the acquisition of additional renewable generation facilities in the second half of 2022 and in the first quarter of 2023. Also contributing to the favorable income tax variance were lower pre-tax earnings during 2023, compared with 2022.

Corporate and Other Segment Contribution to Net Income Attributed to Common Shareholders

	Year Ended December 31		
(in millions)	**2023**	**2022**	**B (W)**
Operating loss	**$ (26.8)**	$ (11.7)	$ (15.1)
Other income, net	**53.3**	14.6	38.7
Interest expense	**257.6**	119.4	(138.2)
Loss before income taxes	**(231.1)**	(116.5)	(114.6)
Income tax benefit	**(68.3)**	(45.7)	22.6
Net loss attributed to common shareholders	**$ (162.8)**	$ (70.8)	$ (92.0)

Operating Loss

The operating loss at the corporate and other segment increased $15.1 million during 2023, compared with 2022, driven by the year-over-year impact from the 2022 resolution of a previously recorded liability as certain outstanding matters reached a favorable outcome. Lower operating income at Wispark also contributed to the higher operating loss, driven by the 2022 positive impact from a payment on a note receivable that was previously written off due to uncertainty regarding its collectability and lower gains related to the sale of land and other assets.

Other Income, Net

Other income, net at the corporate and other segment increased $38.7 million during 2023, compared with 2022. The significant factors impacting the increase in other income, net were:

- A $13.7 million net gain from the investments held in the Integrys rabbi trust during 2023, compared with a $12.6 million net loss during 2022. The gains and losses from the investments held in the rabbi trust partially offset the changes in benefit costs related to deferred compensation, which are primarily included in other operation and maintenance expense in our utility segments. See Note 17, Fair Value Measurements, for more information on our investments held in the Integrys rabbi trust.

- An $18.3 million increase in intercompany interest income, driven by WECI's issuance of a $430.0 million long-term intercompany note to WEC Energy Group in April 2023 and higher interest rates on short-term borrowings to subsidiaries in our operating segments. This intercompany interest income is offset by higher intercompany interest expense in our operating segments and is eliminated in consolidation.

These increases in other income, net were partially offset by a $3.5 million net loss from our equity method investments in technology and energy-focused investment funds during 2023, compared with $6.5 million of net earnings during 2022.

Interest Expense

Interest expense at the corporate and other segment increased $138.2 million during 2023, compared with 2022, primarily due to the impact of long-term debt issuances in September 2022, January 2023, and April 2023. Also driving the increase in interest expense was higher average short-term debt balances and increased short-term debt interest rates.

Income Tax Benefit

The income tax benefit at the corporate and other segment increased $22.6 million during 2023, compared with 2022, driven by a higher pre-tax loss. This increase in the income tax benefit was partially offset by a $5.9 million decrease in excess tax benefits recognized related to stock option exercises.

LIQUIDITY AND CAPITAL RESOURCES

Overview

We expect to maintain adequate liquidity to meet our cash requirements for operation of our businesses and implementation of our corporate strategy through internal generation of cash from operations and access to the capital markets.

The following discussion and analysis of our Liquidity and Capital Resources includes comparisons of our cash flows for the year ended December 31, 2023 with the year ended December 31, 2022. For a similar discussion that compares our cash flows for the year ended December 31, 2022 with the year ended December 31, 2021, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources in Part II of our 2022 Annual Report on Form 10-K, which was filed with the SEC on February 23, 2023.

Cash Flows

The following table summarizes our cash flows during the years ended December 31:

(in millions)	2023	2022	Change in 2023 Over 2022
Cash provided by (used in):			
Operating activities	**$ 3,018.4**	$ 2,060.7	$ 957.7
Investing activities	**(3,558.2)**	(2,642.4)	(915.8)
Financing activities	**522.8**	676.4	(153.6)

Operating Activities

Net cash provided by operating activities increased $957.7 million during 2023, compared with 2022, driven by:

- A $1.54 billion increase in cash from lower payments for fuel and purchased power at our generation plants, as well as lower natural gas costs related to natural gas sold to our customers during 2023, compared with 2022, primarily driven by a decrease in the price of natural gas.

- A $111.3 million increase in cash related to $58.9 million of cash received for income taxes during 2023, compared with $52.4 million of cash paid for income taxes during 2022. The increase in cash received for income taxes was driven by proceeds received in 2023 related to PTCs that were sold to a third party.

- A $24.1 million increase in cash related to higher distributions received from ATC during 2023, compared with 2022.

These increases in net cash provided by operating activities were partially offset by:

- A $403.7 million decrease in cash driven by collateral paid to counterparties during 2023, compared with collateral received from counterparties during 2022, as well as realized losses on derivative instruments recognized during 2023, compared with realized gains recognized during 2022.

- A $168.2 million decrease in cash from higher payments for interest, driven by long-term debt issuances during the last four months of 2022 and early 2023, higher average short-term debt balances, and higher interest rates during 2023, compared with 2022.

- A $127.9 million decrease in cash from higher payments for operating and maintenance expenses. During 2023, our payments were higher associated with previous commitments to charitable projects, transmission costs, and operation and maintenance related to our We Power and Wisconsin generation units, as well as due to the timing of payments for accounts payable.

- A $22.1 million decrease in cash related to higher payments for environmental remediation related to work completed on former manufactured gas plant sites during 2023, compared with 2022.

Investing Activities

Net cash used in investing activities increased $915.8 million during 2023, compared with 2022, driven by:

- The acquisition of a 90% ownership interest in Sapphire Sky in February 2023 for $442.6 million, net of cash acquired of $0.3 million.

- The acquisition of an 80% ownership interest in Samson I in February 2023 for $257.3 million, net of cash acquired of $5.2 million.

- A $178.0 million increase in cash paid for capital expenditures during 2023, compared with 2022, which is discussed in more detail below.

- The acquisition of a 90% ownership interest in Red Barn in April 2023 for $143.8 million.

- The acquisition of a 13.8% ownership interest in West Riverside in June 2023 for $95.3 million. See Note 8, Jointly Owned Utility Facilities, for more information.

- The acquisition of Whitewater in January 2023 for $76.0 million.

- A decrease of $39.1 million in insurance proceeds received during 2023, compared with 2022. In 2022, we received insurance proceeds for property damage related to the PSB water damage claim. See Note 7, Property, Plant, and Equipment, for more information.

- A $36.2 million decrease in proceeds received from the sale of assets during 2023, compared with 2022. See Note 3, Dispositions, for more information.

- An $18.2 million increase in capital contributions paid to transmission affiliates during 2023, compared with 2022. See Note 21, Investment in Transmission Affiliates, for more information.

- A $10.1 million decrease in cash received for the reimbursement of ATC's construction costs during 2023, compared with 2022. See Note 21, Investment in Transmission Affiliates, for more information.

These increases in net cash used in investing activities were partially offset by the acquisition of a 90% ownership interest in Thunderhead in September 2022 for $382.0 million.

For more information on our acquisitions, see Note 2, Acquisitions.

Capital Expenditures

Capital expenditures by segment for the years ended December 31 were as follows:

Reportable Segment (in millions)	2023	2022	Change in 2023 Over 2022
Wisconsin	**$ 1,819.3**	$ 1,610.8	$ 208.5
Illinois	**489.8**	484.9	4.9
Other states	**103.5**	101.1	2.4
Non-utility energy infrastructure	**54.5**	101.8	(47.3)
Corporate and other	**25.8**	16.3	9.5
Total capital expenditures	**$ 2,492.9**	$ 2,314.9	$ 178.0

The increase in cash paid for capital expenditures at the Wisconsin segment during 2023, compared with 2022, was driven by higher payments related to renewable energy projects, upgrades to WE's and WPS's electric and natural gas distribution systems, and construction of WE's and WG's LNG facilities. These increases were partially offset by lower payments for capital expenditures related to the natural gas-fired generation constructed at WPS's Weston power plant site.

The decrease in cash paid for capital expenditures at the non-utility energy infrastructure segment during 2023, compared with 2022, was primarily driven by lower payments for capital expenditures related to wastewater treatment system modifications for We Power's ERGS units. See Note 24, Commitments and Contingencies, for more information.

See Liquidity and Capital Resources – Cash Requirements – Significant Capital Projects below for more information.

Financing Activities

Net cash provided by financing activities decreased $153.6 million during 2023, compared with 2022, driven by:

- A $913.3 million decrease in cash due to higher retirements of long-term debt during 2023, compared with 2022.

- A $66.3 million decrease in cash due to higher dividends paid on our common stock during 2023, compared with 2022. In January 2023, our Board of Directors increased our quarterly dividend by $0.0525 per share (7.2%) effective with the March 2023 dividend payment.

- A $27.3 million decrease in cash proceeds related to fewer stock options exercised during 2023, compared with 2022.

These decreases in net cash provided by financing activities were partially offset by:

- A $626.3 million increase in cash due to $373.7 million of net borrowings of commercial paper during 2023, compared with $252.6 million of net repayments of commercial paper during 2022.

- A $170.7 million increase in cash due to higher issuances of long-term debt during 2023, compared with 2022.

- A $52.6 million increase in cash due to a decrease in common stock purchased during 2023, compared with 2022, to satisfy requirements of our stock-based compensation plans.

Significant Financing Activities

For more information on our financing activities, see Note 13, Short-Term Debt and Lines of Credit, and Note 14, Long-Term Debt.

Cash Requirements

We require funds to support and grow our businesses. Our significant cash requirements primarily consist of capital and investment expenditures, payments to retire and pay interest on long-term debt, the payment of common stock dividends to our shareholders, and the funding of our ongoing operations. Our significant cash requirements are discussed in further detail below.

Significant Capital Projects

We have several capital projects that will require significant capital expenditures over the next three years and beyond. All projected capital requirements are subject to periodic review and may vary significantly from estimates, depending on a number of factors. These factors include environmental requirements, regulatory restraints and requirements, changes in tax laws and regulations, acquisition and development opportunities, market volatility, economic trends, supply chain disruptions, inflation, and interest rates. Our estimated capital expenditures and acquisitions for the next three years are reflected below. These amounts include anticipated expenditures for environmental compliance and certain remediation issues. For a discussion of certain environmental matters affecting us, see Note 24, Commitments and Contingencies.

(in millions)	2024	2025	2026
Wisconsin	$ 2,636.6	$ 3,153.5	$ 3,583.8
Illinois	428.9	392.5	501.3
Other states	123.5	104.1	109.9
Non-utility energy infrastructure	919.6	315.8	29.8
Corporate and other	21.9	14.0	2.0
Total	$ 4,130.5	$ 3,979.9	$ 4,226.8

Our utilities continue to upgrade their electric and natural gas distribution systems to enhance reliability. These upgrades include addressing our aging infrastructure, system hardening, and the AMI program. AMI is an integrated system of smart meters, communication networks, and data management systems that enable two-way communication between utilities and customers.

We are committed to investing in solar, wind, battery storage, and clean natural gas-fired generation. Below are examples of projects that are proposed or currently underway.

- WE and WPS, along with an unaffiliated utility, received PSCW approval to acquire and construct Paris, a utility-scale solar-powered electric generating facility with a battery energy storage system. The project will be located in Kenosha County, Wisconsin and once fully constructed, WE and WPS will collectively own 180 MWs of solar generation and 99 MWs of battery storage of this project. WE's and WPS's combined share of the cost of this project is estimated to be approximately $542 million, with construction of the solar portion and battery storage expected to be completed in 2024 and 2025, respectively.

- WE and WPS, along with an unaffiliated utility, received PSCW approval to acquire and construct Darien, a utility-scale solar-powered electric generating facility. The project will be located in Rock and Walworth counties, Wisconsin and once fully constructed, WE and WPS will collectively own 225 MWs of solar generation. WE's and WPS's combined share of the cost of this project is estimated to be approximately $405 million, with construction expected to be completed in 2024. As part of its order, the PSCW approved battery capacity at this project, which is no longer included in the current capital plan. We will continue to evaluate timing, cost, and feasibility of the installation of batteries.

- WE and WPS, along with an unaffiliated utility, received PSCW approval to acquire Koshkonong, a utility-scale solar-powered electric generating facility. The project will be located in Dane County, Wisconsin and once fully constructed, WE and WPS will collectively own 270 MWs of solar generation. WE's and WPS's combined share of the cost of this project is estimated to be approximately $486 million, with construction expected to be completed in 2026. As part of its order, the PSCW approved battery capacity at this project, which is no longer included in the current capital plan. We will continue to evaluate timing, cost, and feasibility of the installation of batteries.

- In September 2023, WPS filed a request with the PSCW to exercise a second option to acquire an additional 100 MWs of capacity in West Riverside, a combined cycle natural gas plant operated by an unaffiliated utility in Rock County, Wisconsin. In October 2023, WPS filed for approval to assign the second option to purchase West Riverside to WE. If approved, our share of the cost of this ownership interest is expected to be approximately $100 million, with the transaction expected to close in 2024.

- WE and WPS plan to enhance fuel flexibility at the coal-fired ERGS units and Weston Unit 4.

- In February 2024, WE and WPS, along with an unaffiliated utility, filed a request with the PSCW to acquire and construct High Noon, a utility-scale solar-powered electric generating facility. The project will be located in Columbia County, Wisconsin and once fully constructed, WE and WPS will collectively own 270 MWs of solar generation of this project. If approved, WE and WPS's combined share of the cost of the project is estimated to be approximately $576 million, with construction expected to be completed by the end of 2026. Approval for battery capacity at this project was also requested, which is not included in the current capital plan. We will continue to evaluate the timing, cost, and feasibility of the installation of batteries.

- In December 2023, UMERC filed a request with the MPSC to acquire and construct Renegade, a utility-scale solar-powered electric generating facility. The project will be located in Delta County, Michigan and once fully constructed UMERC will own 100 MWs of solar generation. The cost of this project is estimated to be approximately $226 million, with construction expected to be completed by the end of 2026.

In August 2023, the DOC issued a ruling in its investigation into whether new tariffs should be imposed on solar panels and cells imported from multiple southeast Asian countries. See Factors Affecting Results, Liquidity, and Capital Resources – Regulatory, Legislative, and Legal Matters – United States Department of Commerce Complaint and Factors Affecting Results, Liquidity, and Capital Resources – Regulatory, Legislative, and Legal Matters – Uyghur Forced Labor Prevention Act for information on the potential impacts to our solar projects as a result of the DOC ruling and CBP actions related to solar panels, respectively. The expected in-service dates and costs identified above already reflect some of these impacts.

The construction of additional LNG facilities has been proposed as part of the 2024-2028 capital plan. The facilities would provide approximately four Bcf of natural gas supply and are expected to reduce the likelihood of constraints on the natural gas systems during the highest demand days of winter. The total cost of the projects is estimated to be approximately $860 million.

During 2023, PGL continued work on the SMP, a project to replace approximately 2,000 miles of Chicago's aging natural gas pipeline infrastructure. In November 2023, the ICC ordered PGL to pause spending on the SMP until the ICC has a proceeding to determine the optimal method of pipeline replacement and a prudent investment level. The ICC initiated the proceeding on January 31, 2024, and the proceeding is expected to last twelve months. For more information, see Factors Affecting Results, Liquidity, and Capital Resources - Regulatory, Legislative, and Legal Matters - Future Illinois Proceedings. On January 3, 2024, the ICC granted PGL a limited-scope rehearing, which includes the authorized spending for the completion of SMP projects that started in 2023 and the authorized spending for emergency repairs needed to ensure the safety and reliability of our delivery system. As a result, PGL has suspended neighborhood work pending the results of the limited hearing. See Note 26, Regulatory Environment, for more information on the SMP.

The non-utility energy infrastructure line item in the table above includes WECI's previously announced investment in Maple Flats and the purchase in January 2024 of an additional 10% ownership interest in Samson I. See Note 2, Acquisitions, for more information on these projects.

We expect to provide total capital contributions to ATC (not included in the above table) of approximately $345 million from 2024 through 2026. We do not expect to make any contributions to ATC Holdco during that period. WEC's portion of the cost for MISO Tranche 1 is estimated to be approximately $330 million between 2024 and 2028. Tranche 1 is part of MISO's Long Range Transmission Planning initiative to upgrade the grid so that it can reliably accommodate for the shift in generation to lower-carbon resources.

Long-Term Debt

A significant amount of cash is required to retire and pay interest on our long-term debt obligations. See Note 14, Long-Term Debt, for more information on our outstanding long-term debt, including a schedule of our long-term debt maturities over the next five years. The following table summarizes our required interest payments on long-term debt (excluding finance lease obligations) as of December 31, 2023:

	Interest Payments Due by Period				
(in millions)	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Interest payments due on long-term debt [1]	$ 7,966.6	$ 677.7	$ 1,155.5	$ 899.1	$ 5,234.3

[1] The interest due on our variable rate debt is based on the interest rates that were in effect on December 31, 2023.

Common Stock Dividends

On January 18, 2024, our Board of Directors increased our quarterly dividend to $0.835 per share effective with the first quarter of 2024 dividend payment, an increase of 7%. This equates to an annual dividend of $3.34 per share. In addition, the Board of Directors affirmed our dividend policy that continues to target a dividend payout ratio of 65-70% of earnings.

We have been paying consecutive quarterly dividends dating back to 1942 and expect to continue paying quarterly cash dividends in the future. Any payment of future dividends is subject to approval by our Board of Directors and is dependent upon future earnings, capital requirements, and financial and other business conditions. In addition, our ability as a holding company to pay common stock dividends primarily depends on the availability of funds received from our subsidiaries. Various financing arrangements and regulatory requirements impose certain restrictions on the ability of our subsidiaries to transfer funds to us in the form of cash dividends, loans, or advances. We do not believe that these restrictions will materially affect our operations or limit any dividend payments in the foreseeable future. See Note 11, Common Equity, for more information related to these restrictions and our other common stock matters.

Other Significant Cash Requirements

Our utility and non-utility operations have purchase obligations under various contracts for the procurement of fuel, power, and gas supply, as well as the related storage and transportation. These costs are a significant component of funding our ongoing operations. See Note 24, Commitments and Contingencies, for more information, including our minimum future commitments related to these purchase obligations.

In addition to our energy-related purchase obligations, we have commitments for other costs incurred in the normal course of business, including costs related to information technology services, meter reading services, maintenance and other service agreements for certain generating facilities, and various engineering agreements. Our estimated future cash requirements related to these purchase obligations, excluding energy-related obligations, are reflected below.

	Payments Due by Period				
(in millions)	**Total**	**Less Than 1 Year**	**1-3 Years**	**3-5 Years**	**More Than 5 Years**
Purchase orders	$ 612.5	$ 280.4	$ 288.8	$ 41.4	$ 1.9

We have various finance and operating lease obligations. Our finance lease obligations primarily relate to power purchase commitments and land leases for our solar projects. Our operating lease obligations are for office space and land. See Note 15, Leases, for more information, including an analysis of our minimum lease payments due in future years.

We make contributions to our pension and OPEB plans based upon various factors affecting us, including our liquidity position and tax law changes. See Note 20, Employee Benefits, for our expected contributions in 2024 and our expected pension and OPEB payments for the next 10 years. We expect the majority of these future pension and OPEB payments to be paid from our outside trusts. See Sources of Cash–Investments in Outside Trusts below for more information.

In addition to the above, our balance sheet at December 31, 2023 included various other liabilities that, due to the nature of the liabilities, the amount and timing of future payments cannot be determined with certainty. These liabilities include AROs, liabilities for the remediation of manufactured gas plant sites, and liabilities related to the accounting treatment for uncertainty in income taxes. For additional information on these liabilities, see Note 9, Asset Retirement Obligations, Note 24, Commitments and Contingencies, and Note 16, Income Taxes, respectively.

Off-Balance Sheet Arrangements

We are a party to various financial instruments with off-balance sheet risk as a part of our normal course of business, including financial guarantees and letters of credit that support construction projects, commodity contracts, and other payment obligations. We believe that these agreements do not have, and are not reasonably likely to have, a current or future material effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources. See Note 13, Short-Term Debt and Lines of Credit, Note 19, Guarantees, and Note 23, Variable Interest Entities, for more information.

Sources of Cash

Liquidity

We anticipate meeting our short-term and long-term cash requirements to operate our businesses and implement our corporate strategy through internal generation of cash from operations and access to the capital markets, which allows us to obtain external short-term borrowings, including commercial paper and term loans, and intermediate or long-term debt securities, as well as other types of securities. In addition, in January 2024, we started issuing common equity through a combination of our employee benefit plans and stock purchase and dividend reinvestment plan. We also anticipate issuing common equity through an at-the-market program in the future. Cash generated from operations is primarily driven by sales of electricity and natural gas to our utility customers, reduced by costs of operations. Our access to the capital markets is critical to our overall strategic plan and allows us to supplement cash flows from operations with external borrowings to manage seasonal variations, working capital needs, commodity price fluctuations, unplanned expenses, and unanticipated events. Subject to market conditions and other factors, we may repurchase our debt securities through open market purchases, privately negotiated transactions and/or other types of transactions. In January and February, 2024, pursuant to a tender offer, we purchased $122.1 million aggregate principal amount of the $500.0 million outstanding of our 2007 Junior Notes.

WEC Energy Group, WE, WPS, WG, and PGL maintain bank back-up credit facilities, which provide liquidity support for each company's obligations with respect to commercial paper and for general corporate purposes. We review our bank back-up credit facility needs on an ongoing basis and expect to be able to maintain adequate credit facilities to support our operations.

The amount, type, and timing of any financings in 2024, as well as in subsequent years, will be contingent on investment opportunities and our cash requirements and will depend upon prevailing market conditions, regulatory approvals for certain subsidiaries, and other factors. Our regulated utilities plan to maintain capital structures consistent with those approved by their respective regulators. For more information on our utilities approved capital structures, see Item 1. Business – E. Regulation.

The issuance of securities by our utility companies is subject to the approval of the applicable state commissions or FERC. Additionally, with respect to the public offering of securities, we, WE, and WPS file registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the appropriate regulatory authorities, as well as the securities registered under the 1933 Act, are closely monitored and appropriate filings are made to ensure flexibility in the capital markets.

At December 31, 2023, our current liabilities exceeded our current assets by $2,319.1 million. We do not expect this to have an impact on our liquidity as we currently believe that our cash and cash equivalents, our available capacity under existing revolving credit facilities, cash generated from ongoing operations, and access to the capital markets are adequate to meet our short-term and long-term cash requirements.

See Note 13, Short-Term Debt and Lines of Credit, and Note 14, Long-Term Debt, for more information about our credit facilities and debt securities.

Investments in Outside Trusts

We maintain investments in outside trusts to fund the obligation to provide pension and certain OPEB benefits to current and future retirees. As of December 31, 2023, these trusts had investments of approximately $3.5 billion, consisting of fixed income and equity securities, that are subject to the volatility of the stock market and interest rates. The performance of existing plan assets, long-term discount rates, changes in assumptions, and other factors could affect our future contributions to the plans, our financial position if our accumulated benefit obligation exceeds the fair value of the plan assets, and future results of operations related to changes in pension and OPEB expense and the assumed rate of return. For additional information, see Note 20, Employee Benefits.

Capitalization Structure

The following table shows our capitalization structure as of December 31, 2023 and 2022, as well as an adjusted capitalization structure that we believe is consistent with how a majority of the rating agencies currently view our 2007 Junior Notes:

	2023		2022	
(in millions)	**Actual**	**Adjusted**	**Actual**	**Adjusted**
Common shareholders' equity	**$ 11,724.2**	**$ 11,974.2**	$ 11,376.9	$ 11,626.9
Preferred stock of subsidiary	**30.4**	**30.4**	30.4	30.4
Long-term debt (including current portion)	**16,777.0**	**16,527.0**	15,647.4	15,397.4
Short-term debt	**2,020.9**	**2,020.9**	1,647.1	1,647.1
Total capitalization	**$ 30,552.5**	**$ 30,552.5**	$ 28,701.8	$ 28,701.8
Total debt	**$ 18,797.9**	**$ 18,547.9**	$ 17,294.5	$ 17,044.5
Ratio of debt to total capitalization	**61.5 %**	**60.7 %**	60.3 %	59.4 %

Included in long-term debt on our balance sheets as of December 31, 2023 and 2022, is $500.0 million principal amount of the 2007 Junior Notes. The adjusted presentation attributes $250.0 million of the 2007 Junior Notes to common shareholders' equity and $250.0 million to long-term debt. In January and February, 2024, pursuant to a tender offer, we purchased $122.1 million aggregate principal amount of the $500.0 million outstanding of our 2007 Junior Notes.

The adjusted presentation of our consolidated capitalization structure is included as a complement to our capitalization structure presented in accordance with GAAP. Management evaluates and manages our capitalization structure, including our total debt to total capitalization ratio, using the GAAP calculation as adjusted to reflect the treatment of the 2007 Junior Notes by the majority of rating agencies. Therefore, we believe the non-GAAP adjusted presentation reflecting this treatment is useful and relevant to investors in understanding how management and the rating agencies evaluate our capitalization structure.

Debt Covenants

Certain of our short-term and long-term debt agreements contain financial covenants that we must satisfy, including debt to capitalization ratios and debt service coverage ratios. At December 31, 2023, we were in compliance with all such covenants related to outstanding short-term and long-term debt. We expect to be in compliance with all such debt covenants for the foreseeable future. See Note 13, Short-Term Debt and Lines of Credit, Note 14, Long-Term Debt, and Note 11, Common Equity, for more information.

Credit Rating Risk

Cash collateral postings and prepayments made with external parties, including postings related to exchange-traded contracts, and cash collateral posted by external parties were immaterial as of December 31, 2023. From time to time, we may enter into commodity contracts that could require collateral or a termination payment in the event of a credit rating change to below BBB- at S&P Global Ratings, a division of S&P Global Inc., and/or Baa3 at Moody’s Investors Service, Inc. If WE had a sub-investment grade credit rating at December 31, 2023, it could have been required to post $100 million of additional collateral or other assurances pursuant to the terms of a PPA. We also have other commodity contracts that, in the event of a credit rating downgrade, could result in a reduction of our unsecured credit granted by counterparties.

In addition, access to capital markets at a reasonable cost is determined in large part by credit quality. Any credit ratings downgrade could impact our ability to access capital markets.

On May 2, 2023, S&P Global Inc. affirmed WEC Energy Group’s ratings and revised its outlook to negative from stable, citing weakening financial measures. S&P Global Inc. upgraded WEC Energy Group’s outlook back to stable on November 21, 2023, following their review of our updated five year capital and financing plan. The factors leading to the upgraded outlook included the maintenance of improving financial metrics and the expected reduction in our exposure to coal fired generation through the rest of the decade. The ratings outlooks on our utilities remain stable.

Subject to other factors affecting the credit markets as a whole, we believe our current ratings should provide a significant degree of flexibility in obtaining funds on competitive terms. However, these security ratings reflect the views of the rating agency only. An explanation of the significance of these ratings may be obtained from the rating agency. Such ratings are not a recommendation to buy, sell, or hold securities. Any rating can be revised upward or downward or withdrawn at any time by a rating agency.

FACTORS AFFECTING RESULTS, LIQUIDITY, AND CAPITAL RESOURCES

Competitive Markets

Electric Utility Industry

The FERC supports large RTOs, which directly impacts the structure of the wholesale electric market. Due to the FERC's support of RTOs, MISO uses the MISO Energy Markets to carry out its operations, including the use of LMPs to value electric transmission congestion and losses. Increased competition in the retail and wholesale markets, which may result from restructuring efforts, could have a significant and adverse financial impact on us.

Wisconsin

Electric utility revenues in Wisconsin are regulated by the PSCW. The PSCW continues to maintain the position that the question of whether to implement electric retail competition in Wisconsin should ultimately be decided by the Wisconsin legislature. No such legislation has been introduced in Wisconsin to date. It is uncertain when, if at all, retail choice might be implemented in Wisconsin.

Michigan

Michigan has adopted a limited retail choice program. Under Michigan law, our retail customers may choose an alternative electric supplier to provide power supply service. As a result, some of our small retail customers have switched to an alternative electric supplier. At December 31, 2023, Michigan law limited customer choice to 10% of an electric utility's Michigan retail load. Our iron ore mine customer, Tilden, is exempt from this 10% cap based on current law, but Tilden is required under a long-term agreement to purchase electric power from UMERC through March 2039. In addition, certain load increases by facilities already using an alternative electric supplier can still be serviced by their alternative electric supplier, when various conditions exist, even if the cap has already been met. When a customer switches to an alternative electric supplier, we continue to provide distribution and customer service functions for the customer.

Natural Gas Utility Industry

We offer natural gas transportation services to our customers that elect to purchase natural gas directly from a third-party supplier. Since these transportation customers continue to use our distribution systems to transport natural gas to their facilities, we earn distribution revenues from them. As such, the loss of revenue associated with the cost of natural gas that our transportation customers purchase from third-party suppliers has little impact on our net income, as it is substantially offset by an equal reduction to natural gas costs.

Wisconsin

Our Wisconsin utilities offer both natural gas transportation service and interruptible natural gas sales to enable customers to better manage their energy costs. Customers continue to switch between firm system supply, interruptible system supply, and transportation service each year as the economics and service options change.

Due to the PSCW's previous proceedings on natural gas industry regulation in a competitive environment, the PSCW currently provides all Wisconsin customer classes with competitive markets the option to choose a third-party natural gas supplier. All of our Wisconsin non-residential customer classes have competitive market choices and, therefore, can purchase natural gas directly from either a third-party supplier or their local natural gas utility. Since third-party suppliers can be used in Wisconsin, the PSCW has also adopted standards for transactions between a utility and its natural gas marketing affiliates.

We are currently unable to predict the impact, if any, of potential future industry restructuring on our results of operations or financial position.

Illinois

Absent extraordinary circumstances, potential competitors are not allowed to construct competing natural gas distribution systems in the service territories for PGL and NSG. A charter from the State of Illinois gives PGL the right to provide natural gas distribution service in the City of Chicago as a public utility. Further, the "first in the field" and public interest standards limit the ability of potential competitors to operate in an existing utility service territory. In addition, we believe it would be impractical to construct competing duplicate distribution facilities due to the high cost of installation.

Since 2002, PGL and NSG have, under ICC-approved tariffs, provided their customers with the option to choose a third-party natural gas supplier. There are no state laws requiring PGL and NSG to make this choice option available to customers, but since this option is currently provided to our Illinois customers under tariff, ICC approval would be needed to withdraw those tariffs.

An interstate pipeline may seek to provide transportation service directly to our Illinois end users, which would bypass our natural gas transportation service. However, PGL and NSG have anti-bypass tariffs approved by the ICC, which allow them to negotiate rates with customers that are potential bypass candidates to help ensure that such customers continue to use utility transportation service.

Minnesota

Natural gas utilities in the state of Minnesota do not have exclusive franchise service territories and, as a matter of law and policy, natural gas utilities may compete for new customers. However, natural gas utilities have customarily avoided competing for existing customers of other utilities, as there would be duplicative utility facilities and/or increased costs to customers. If this approach were to change, it could lead to a greater level of competition amongst utilities to obtain customers and potentially adversely impact our results of operations.

MERC offers both natural gas transportation service and interruptible natural gas sales to enable customers to better manage their energy costs. Customers continue to switch between firm system supply, interruptible system supply, and transportation service each year as the economics and service options change. MERC has provided its commercial and industrial customers with the option to choose a third-party natural gas supplier since 2006. We are not required by the MPUC or state law to make this choice option available to customers, but since this option is currently provided to our Minnesota commercial and industrial customers, we would need MPUC approval to eliminate it.

Michigan

The option to choose a third-party natural gas supplier has been provided to UMERC’s natural gas customers (formerly WPS’s Michigan natural gas customers) since the late 1990s and MGU's customers since 2005. We are not required by the MPSC or state law to make this choice option available to customers, but since this option is currently provided to our Michigan customers, we would need MPSC approval to eliminate it.

Regulatory, Legislative, and Legal Matters

Regulatory Recovery

Our utilities account for their regulated operations in accordance with accounting guidance under the Regulated Operations Topic of the FASB ASC. Our rates are determined by various regulatory commissions. See Item 1. Business – E. Regulation for more information on these commissions.

Regulated entities are allowed to defer certain costs that would otherwise be charged to expense if the regulated entity believes the recovery of those costs is probable. We record regulatory assets pursuant to generic and/or specific orders issued by our regulators. Recovery of the deferred costs in future rates is subject to the review and approval by those regulators. We assume the risks and benefits of ultimate recovery of these items in future rates. If the recovery of the deferred costs, including those referenced below, is not approved by our regulators, the costs would be charged to income in the current period. Regulators can impose liabilities on a prospective basis for amounts previously collected from customers and for amounts that are expected to be refunded to customers. We record these items as regulatory liabilities. See Note 6, Regulatory Assets and Liabilities, for more information on our regulatory assets and liabilities.

The rates of PGL and NSG include a UEA rider for cost recovery or refund of uncollectible expense based on the difference between actual uncollectible write-offs and the amounts recovered in rates. The UEA rider is subject to an annual reconciliation whereby costs are reviewed for accuracy and prudency by the ICC. In May 2023, the ICC issued a written order on PGL's and NSG's 2018 UEA rider reconciliation. The order requires a $15.4 million and $0.7 million refund to ratepayers at PGL and NSG, respectively. These amounts are being refunded over a period of nine months, which began on September 1, 2023. In June 2023, the ICC denied PGL's and NSG's application requesting a rehearing of the ICC's May 2023 order. In July 2023, PGL and NSG petitioned the Illinois Appellate Court for review of the ICC orders. Their appeal is still pending.

In January 2014, the ICC approved PGL's use of the QIP rider as a recovery mechanism for costs incurred related to investments in QIP. This rider, which was in effect until December 1, 2023, continues to be subject to an annual reconciliation whereby costs are reviewed for accuracy and prudency. In March 2023, PGL filed its 2022 reconciliation with the ICC, which, along with the reconciliations from 2016 through 2021, are still pending. In addition, costs incurred during 2023 under the QIP rider are also still subject to reconciliation and review. Annual costs included in PGL's QIP rider have ranged from $192 million to $348 million. As of December 31, 2023, there can be no assurance that all costs incurred under the QIP rider during the open reconciliation years, which include 2016 through 2023, will be deemed recoverable by the ICC. Disallowances by the ICC, if any, could be material and have a material adverse impact on our results of operations.

See Note 26, Regulatory Environment, for more information regarding recent and pending rate proceedings, orders, and investigations involving our utilities.

Future Illinois Proceedings

In the PGL rate order issued by the ICC in November 2023, the ICC ordered PGL to pause spending on its SMP until the ICC completes a proceeding to determine the optimal method for replacing aging natural gas infrastructure and a prudent investment level. The ICC initiated the proceeding on January 31, 2024, and the proceeding is expected to last 12 months.

In addition, the ICC ordered staff to develop a plan for a "Future of Gas" proceeding. The goal of this proceeding will be to explore the issues involved with decarbonization of the gas distribution system in Illinois and recommend any future ICC action or legislative changes needed. It will include the formal exploration and consideration of the role of natural gas in the future, including in the context of the state’s environmental and energy policy goals. The proceeding will include a broad range of stakeholders, including Illinois utilities and other interested parties. Once initiated, the “Future of Gas” proceeding is expected to last at least one year.

At this time, we cannot predict the ultimate outcome of these proceedings or the resulting impact to our natural gas operations in Illinois. Future natural gas investment opportunities in Illinois could be negatively impacted depending upon the outcomes. See Note 26, Regulatory Environment, for more information regarding the November 2023 ICC rate order.

Chicago Decarbonization Efforts

The CABO was introduced at a meeting of the Chicago city council held on January 24, 2024. If approved, this ordinance would set an indoor emissions standard that would require zero-to-low-emission energy systems in newly built commercial and residential buildings and major building additions in the city of Chicago. The proposed emission standards would effectively prohibit the use of natural gas in new buildings and homes and require electric heat and appliances. The CABO would not impact existing homes and businesses. In addition, certain buildings and equipment, such as hospitals, commercial kitchens, and back-up generators, would be exempt from the new emission limits.

In response to the CABO, a resolution was also introduced that would require the formation of a working group comprised of various subject matter experts to analyze the costs of converting buildings from natural gas to electricity, the costs for additional electric generation capacity needed for future building conversions, and the impact of shifting natural gas system costs from new construction to existing buildings if electrification measures are adopted. If the resolution is passed, this analysis would need to be completed prior to the adoption of any decarbonization initiatives, such as the CABO.

If approved by the city council, the CABO is expected to become effective one year after the approval date. PGL's future natural gas operations could be materially adversely impacted if the CABO is passed.

Petitions Before PSCW Regarding Third-Party Financed Distributed Energy Resources

In May 2022, two petitions were filed with the PSCW requesting a declaratory ruling that the owner of a third-party financed DER is not a "public utility" as defined under Wisconsin law and, therefore, is not subject to the PSCW's jurisdiction under any statute or rule regulating public utilities. The parties that filed the petitions provide financing to their customers for installation of DERs (including solar panels and energy storage) on the customer's property. A DER is connected to the host customer's utility meter and is used for the customer's energy needs. It may also be connected to the grid for distribution.

In July 2022, the PSCW found that the specific facts and circumstances merited the opening of a docket for each petition to consider whether to grant all or part of the requested declaratory ruling.

In December 2022, the PSCW granted one petitioner's request for a declaratory ruling, finding that the owner of the third-party financed DER at issue in the petitioner's brief is not a public utility under Wisconsin law. The ruling was limited to the specific facts and circumstances of the lease presented in that petition. A petition by the WUA to reopen or rehear the case expired without action by the PSCW. The WUA has filed an appeal which is pending consideration by the circuit court. The second petition was denied. Although the finding in the first petition was limited to the specific facts and circumstances of the lease presented in that petition, similar findings or a broader policy position could adversely impact our business operations.

Climate and Equitable Jobs Act

On September 15, 2021, the state of Illinois signed into law the Climate and Equitable Jobs Act. This legislation includes, among other things, a path for Illinois to move towards 100% clean energy, expanded commitments to energy efficiency and renewable energy, additional consumer protections, and expanded ethics reform. The provisions in this legislation that had the potential to have the most significant financial impact on PGL and NSG related to the new consumer protection requirements.

Effective September 15, 2021, the new legislation prohibits utilities from charging customers a fee when they elect to pay for service with a credit card. Utilities are now required to incur these expenses and seek recovery through a rate proceeding or by establishing a recovery mechanism. In December 2021, the ICC approved the use of a TPTFA rider for PGL. The TPTFA rider allowed PGL to recover the costs incurred for these third-party transaction fees prior to them being included in PGL's base rates. Effective December 1, 2023, PGL began recovering these costs through its base rates. See Note 26, Regulatory Environment, for more information on the TPTFA rider. NSG has been recovering costs related to these third-party transaction fees through its base rates since September 15, 2021.

In accordance with the new legislation, effective January 1, 2023, natural gas utilities are no longer allowed to charge late payment fees to certain low-income residential customers. As a result of the ICC's November 2023 rate orders, we do not expect this legislation to have a significant impact on our results of operations.

Uyghur Forced Labor Prevention Act

The CBP issued a WRO in June 2021, applicable to certain silica-based products originating from the Xinjiang Uyghur Autonomous Region of China (Xinjiang), such as polysilicon, included in the manufacturing of solar panels. In June 2022, the WRO was superseded by the implementation of the UFLPA. The UFLPA establishes a rebuttable presumption that any imports wholly or partially manufactured in Xinjiang are prohibited from entering the United States. While our suppliers were able to provide the CBP sufficient documentation to meet WRO compliance requirements, and we expect the same will be true for UFLPA purposes, we cannot currently predict what, if any, long-term impact the UFLPA will have on the overall supply of solar panels into the United States and whether we will experience any further impacts to the timing and cost of solar projects included in our long-term capital plan.

United States Department of Commerce Complaints

In February 2022, a California based company filed a petition (Antidumping and Countervailing Duties) with the DOC seeking to impose new tariffs on solar panels and cells imported from multiple countries, including Malaysia, Vietnam, Thailand, and Cambodia. The petitioners claimed that Chinese solar manufacturers are shifting products to these countries to avoid the tariffs required on products imported from China and requested that the DOC conduct a country-wide inquiry into each of the four countries. After investigation, in December 2022, the DOC announced its preliminary determination that certain companies are circumventing anti-dumping and countervailing duty orders on solar cells and modules from China.

In August 2023, the DOC issued its final decision, substantially affirming its preliminary determination that circumvention was occurring in each of the four Southeast Asian countries noted above. In its decision, the DOC affirmed that the Biden Administration’s current 24-month tariff moratorium will remain in effect until June 6, 2024, subject to certain use and installation requirements, at which time tariffs are expected to resume. In December 2023, two U.S. solar manufacturers filed a challenge to this moratorium in the United States Court of International Trade.

The Biden Administration also invoked the Defense Production Act to accelerate the production of solar panels in the U.S.; however, the DOC’s ruling may have an adverse impact on the solar industry overall. Additionally, the Biden Administration's actions did not address whether WROs applied to panels under previous complaints would be affected. At this time, we do not expect this final ruling to have a material impact on our results of operations.

Infrastructure Investment and Jobs Act

In November 2021, President Biden signed into law the Infrastructure Investment and Jobs Act, which provides for approximately $1.2 trillion of federal spending over a five year period, including approximately $85 billion for investments in power, utilities, and renewables infrastructure across the United States. We expect funding from this Act will support the work we are doing to reduce GHG emissions, increase EV charging, and strengthen and protect the energy grid. Funding in the Act should also help to expand emerging technologies, like hydrogen and carbon management, as we continue the transition to a clean energy future. We believe the Infrastructure Investment and Jobs Act will accelerate investment in projects that will help us meet our net zero emission goals to the benefit of our customers, the communities we serve, and our company.

Inflation Reduction Act

In August 2022, President Biden signed into law the IRA, which provides for $258 billion in energy-related provisions over a 10-year period. The provisions of the IRA are intended to, among other things, lower gasoline and electricity prices, incentivize domestic clean energy investment, manufacturing, and production, and promote reductions in carbon emissions. We believe that we and our customers can benefit from the IRA’s provisions that extend tax benefits for renewable technologies, increase or restore higher rates for PTCs, add an option to claim PTCs for solar projects, expand qualified ITC facilities to include standalone energy storage, and its provision to allow companies to transfer tax credits generated from renewable projects. Under this new IRA transferability option, we entered into a sales agreement in September 2023 to sell substantially all of our 2023 PTCs to a third party. See Note 1(q), Income Taxes, for more information about the impact of these sales. The IRA also implements a 15% corporate alternative minimum tax and a 1% excise tax on stock repurchases. Although significant regulatory guidance is expected on the tax provisions in the IRA, we currently believe the provisions on alternative minimum tax and stock repurchases will not have a material impact on us. Overall, we believe the IRA will help reduce our cost of investing in projects that will support our commitment to reduce emissions and provide customers affordable, reliable, and clean energy over the longer term.

Return on Equity Incentive for Membership in a Transmission Organization

The FERC currently allows transmission utilities, including ATC, to increase their ROE by 50 basis points as an incentive for membership in a transmission organization, such as MISO. This incentive was established to stimulate infrastructure development and to support the evolving electric grid. However, a Notice of Proposed Rulemaking was issued by the FERC on April 15, 2021, proposing to limit the 50 basis point increase in ROE to only be available to transmission utilities initially joining a transmission organization for the first three years of membership. If this proposal becomes a final rule, ATC would be required to submit, within 30 days of the final rule's effective date, a compliance filing eliminating the 50 basis point incentive from its tariff. As a result, we estimate that this proposal, if adopted, would reduce our future after-tax equity earnings from ATC by approximately $7 million annually on a prospective basis. The transmission costs WE, WPS, and UMERC are required to pay ATC after the effective date would also be reduced by this proposal.

American Transmission Company Allowed Return on Equity Complaints

The ROE allowed by the FERC helps determine how much transmission owners, such as ATC, earn on their transmission assets as well as how much consumers pay for those assets. When two complaints were filed arguing the base ROE for MISO transmission owners, including ATC, was too high, the FERC started analyzing the base ROE for these transmission owners.

The base ROEs listed in the two ROE complaint sections below do not include the 50 basis point ROE incentive currently provided for membership in a transmission organization. See the Return on Equity Incentive for Membership in a Transmission Organization section above for more information on this incentive.

First Return on Equity Complaint

In November 2013, a group of MISO industrial customers filed a complaint with the FERC asking that the FERC order a reduction to the base ROE used by MISO transmission owners, including ATC, from 12.2% to 9.15%. Due to this complaint, the FERC and the D.C. Circuit Court of Appeals issued the following orders and opinion. The refunds resulting from these orders and opinion are also described below.

- Orders Issued by the FERC
    - September 2016 Order – On September 28, 2016, the FERC issued an order reducing the base ROE for MISO transmission owners to 10.32% for the period covered by the first complaint, November 12, 2013 through February 11, 2015 and September 28, 2016 going forward.

    - November 2019 Order – On November 21, 2019, the FERC issued another order after directing MISO transmission owners and other stakeholders to provide briefs and comments on a proposed change to the methodology for calculating base ROE. In this order, the FERC expanded its base ROE methodology to include the capital-asset pricing model in addition to the discounted cash flow model to better reflect how investors make their investment decisions. The FERC also rejected the use of the risk premium model as part of its base ROE methodology in this order. The FERC's modified methodology further reduced the base ROE for all MISO transmission owners, including ATC, to 9.88% for the period covered by the first complaint. In response to this FERC decision, requests for the FERC to rehear the November 2019 Order in its entirety were filed by various parties.

    - May 2020 Order – On May 21, 2020, the FERC issued an order that granted in part and denied in part the requests to rehear the November 2019 Order. In this May 2020 Order, the FERC made additional revisions to its base ROE methodology, including reinstating the use of the risk premium model. The additional revisions made by the FERC increased the base ROE for all MISO transmission owners, including ATC, from the 9.88% authorized in the November 2019 Order to 10.02% for the period covered by the first complaint. Various parties then filed requests to rehear certain parts of the May 2020 Order with the FERC.

    - November 2020 Order – In response to the rehearing requests filed concerning certain parts of the May 2020 Order, the FERC issued an order in November 2020 that confirmed the ROE previously authorized in its May 2020 Order.

    - Refunds – Due to the base ROE changes resulting from these FERC orders, ATC was required to provide refunds, with interest, for the 15-month refund period from November 12, 2013 through February 11, 2015 and for the period from September 28, 2016 through November 19, 2020. In January 2022, ATC completed providing WE, WPS, and UMERC with the net refunds related to the transmission costs they paid during the period covered by the first complaint. The refunds were applied to WE's and WPS's PSCW-approved escrow accounting for transmission expense.

- Opinion Issued by the D.C. Circuit Court of Appeals

  - August 2022 Decision – Since several petitions for review were filed with the D.C. Circuit Court of Appeals concerning this ROE complaint, the D.C. Circuit Court of Appeals issued an opinion on August 9, 2022, addressing these petitions. In its August 2022 Decision, the D.C. Circuit Court of Appeals ruled the FERC failed to adequately explain why it reinstated the use of the risk premium model as part of its ROE methodology in its May 2020 Order after previously rejecting the model in its November 2019 Order. Due to this ruling, the D.C. Circuit Court of Appeals vacated the FERC's previous orders and remanded the issue of determining an appropriate base ROE for MISO transmission owners back to the FERC for additional proceedings. As of December 31, 2023, the FERC had not provided a ruling in response to the August 2022 Decision issued by the D.C. Circuit Court of Appeals.

  - Refunds – Since the FERC is required to conduct more proceedings, additional refunds could still be required for the 15-month period from November 12, 2013 through February 11, 2015 and for the period from September 28, 2016 until the date of any future order. Therefore, ATC recorded a liability on its financials for these potential refunds, which reduced our equity earnings from ATC by $18.6 million during the third quarter of 2022. The liability recorded by ATC is based on a 9.88% base

ROE for the first complaint period. If it is ultimately determined a refund is required for the first complaint period, we would not expect any such refund to have a material impact on our financial statements or results of operations in the future. In addition, WE, WPS, and UMERC would be entitled to receive a portion of the refund from ATC for the benefit of their customers.

Second Return on Equity Complaint

In February 2015, a second complaint was filed with the FERC requesting a reduction in the base ROE used by MISO transmission owners, including ATC, to 8.67%, with a refund effective date retroactive to February 12, 2015. To resolve this complaint, the following orders and opinion were issued by the FERC and the D.C. Circuit Court of Appeals. The orders and opinion discussed below are the same orders and opinion described above in the first complaint section.

- Orders Issued by the FERC
  - November 2019 Order – Similar to the first complaint, the November 2019 Order stated the newly calculated base ROE of 9.88% was also reasonable for the period covered by the second complaint, February 12, 2015 through May 10, 2016. However, in the November 2019 Order, the FERC relied on certain provisions of the Federal Power Act to dismiss the second complaint and to determine refunds were not allowed for this period.
  - May 2020 Order – In its May 2020 Order, the FERC stated the newly calculated base ROE of 10.02% was also reasonable for the period covered by the second complaint. However, the FERC relied on the same provisions of the Federal Power Act to again dismiss the complaint and to determine refunds were not allowed for this period. In addition, the FERC denied in its May 2020 Order the requests to rehear both the dismissal of the second complaint and the determination that no refunds are allowed for the second complaint period.
- Opinion Issued by the D.C. Circuit Court of Appeals
  - August 2022 Decision - The August 2022 Decision issued by the D.C. Circuit Court of Appeals affirmed both the FERC’s dismissal of the second complaint and the FERC’s finding that no refunds are allowed for the second complaint period. Therefore, during the third quarter of 2022, we reduced the liability previously recorded for the potential refunds related to the second complaint period by $39.1 million, which increased our equity earnings from ATC.

Environmental Matters

See Note 24, Commitments and Contingencies, for a discussion of certain environmental matters affecting us, including rules and regulations relating to air quality, water quality, and land quality.

Market Risks and Other Significant Risks

We are exposed to market and other significant risks as a result of the nature of our businesses and the environments in which those businesses operate. These risks, described in further detail below, include but are not limited to:

Commodity Costs

In the normal course of providing energy, we are subject to market fluctuations in the costs of coal, natural gas, purchased power, and fuel oil used in the delivery of coal. We manage our fuel and natural gas supply costs through a portfolio of short and long-term procurement contracts with various suppliers for the purchase of coal, natural gas, and fuel oil. In addition, we manage the risk of price volatility through natural gas and electric hedging programs.

Embedded within our utilities' rates are amounts to recover fuel, natural gas, and purchased power costs. Our utilities have recovery mechanisms in place that generally allow them to recover or refund all or a portion of the changes in prudently incurred fuel, natural gas, and purchased power costs from rate case-approved amounts. See Item 1. Business – E. Regulation for more information on these mechanisms.

Higher commodity costs can increase our working capital requirements, result in higher gross receipts taxes, and lead to increased energy efficiency investments by our customers to reduce utility usage and/or fuel substitution. Higher commodity costs combined with slower economic conditions also expose us to greater risks of accounts receivable write-offs as more customers are unable to pay their bills. See Note 5, Credit Losses, for more information on riders and other mechanisms that allow for cost recovery or refund of uncollectible expense.

Weather

Our utilities' rates are based upon estimated normal temperatures. Our electric utility margins are unfavorably sensitive to below normal temperatures during the summer cooling season and, to some extent, to above normal temperatures during the winter heating season. Our natural gas utility margins are unfavorably sensitive to above normal temperatures during the winter heating season. PGL, NSG, and MERC have decoupling mechanisms in place that help reduce the impacts of weather. Decoupling mechanisms differ by state and allow utilities to recover or refund certain differences between actual and authorized margins. A summary of actual weather information in our utilities' service territories during 2023 and 2022, as measured by degree days, can be found in Results of Operations.

Interest Rates

We are exposed to interest rate risk resulting from our short-term and long-term borrowings and projected near-term debt financing needs. We manage exposure to interest rate risk by limiting the amount of our variable rate obligations and continually monitoring the effects of market changes on interest rates. When it is advantageous to do so, we enter into long-term fixed rate debt. We may also enter into derivative financial instruments, such as swaps, to mitigate interest rate exposure.

Based on the variable rate debt outstanding at December 31, 2023 and 2022, a hypothetical increase in market interest rates of one percentage point would have increased annual interest expense by $25.2 million and $21.4 million in 2023 and 2022, respectively. This sensitivity analysis was performed assuming a constant level of variable rate debt during the period and an immediate increase in interest rates, with no other changes for the remainder of the period.

Marketable Securities Return

We use various trusts to fund our pension and OPEB obligations. These trusts invest in debt and equity securities. Changes in the market prices of these assets can affect future pension and OPEB expenses. Additionally, future contributions can also be affected by the investment returns on trust fund assets. The financial risks associated with investment returns are mitigated at our Wisconsin utilities through the requirement that WE, WPS, and WG implement escrow accounting treatment for pension and OPEB costs in 2023 and 2024, as required by the December 2022 rate order issued by the PSCW. We also believe that the financial risks associated with investment returns would be partially mitigated at our other utilities through future rate actions by regulators. See Note 26, Regulatory Environment, for more information on 2023 and 2024 rates at our Wisconsin utilities.

The fair value of our trust fund assets and expected long-term returns were approximately:

(in millions)	As of December 31, 2023	Expected Return on Assets in 2024
Pension trust funds	$ **2,665.8**	6.62 %
OPEB trust funds	$ **829.6**	6.50 %

Fiduciary oversight of the pension and OPEB trust fund investments is the responsibility of an Investment Trust Policy Committee. The Committee works with external actuaries and investment consultants on an ongoing basis to establish and monitor investment strategies and target asset allocations. Forecasted cash flows for plan liabilities are regularly updated based on annual valuation results. Target asset allocations are determined utilizing projected benefit payment cash flows and risk analyses of appropriate investments. The targeted asset allocations are intended to reduce risk, provide long-term financial stability for the plans, and maintain funded levels which meet long-term plan obligations while preserving sufficient liquidity for near-term benefit payments. Investment strategies utilize a wide diversification of asset types and qualified external investment managers.

We consult with our investment advisors on an annual basis to help us forecast expected long-term returns on plan assets by reviewing actual historical returns and calculating expected total trust returns using the weighted-average of long-term market returns for each of the major target asset categories utilized in the funds.

Economic Conditions

We have electric and natural gas utility operations that serve customers in Wisconsin, Illinois, Minnesota, and Michigan. As such, we are exposed to market risks in the regional Midwest economy. In addition, any economic downturn or disruption of national or international markets could adversely affect the financial condition of our customers and demand for their products, which could affect their demand for our products.

Inflation and Supply Chain Disruptions

We continue to monitor the impact of inflation and supply chain disruptions. We monitor the costs of medical plans, fuel, transmission access, construction costs, regulatory and environmental compliance costs, and other costs in order to minimize inflationary effects in future years, to the extent possible, through pricing strategies, productivity improvements, and cost reductions. We monitor the global supply chain, and related disruptions, in order to ensure we are able to procure the necessary materials and other resources necessary to both maintain our energy services in a safe and reliable manner and to grow our infrastructure in accordance with our capital plan. For additional information concerning risks related to inflation and supply chain disruptions, see the four risk factors below.

- Item 1A. Risk Factors – Risks Related to the Operation of Our Business – Public health crises, including epidemics and pandemics, could adversely affect our business functions, financial condition, liquidity, and results of operations.

- Item 1A. Risk Factors – Risks Related to the Operation of Our Business – Our operations and corporate strategy may be adversely affected by supply chain disruptions and inflation.

- Item 1A. Risk Factors – Risks Related to the Operation of Our Business – We are actively involved with multiple significant capital projects, which are subject to a number of risks and uncertainties that could adversely affect project costs and completion of construction projects.

- Item 1A. Risk Factors – Risks Related to Economic and Market Volatility – Fluctuating commodity prices could negatively impact our operations.

For additional information concerning other risk factors, including market risks, see the Cautionary Statement Regarding Forward-Looking Information at the beginning of this report and Item 1A. Risk Factors.

Critical Accounting Policies and Estimates

The preparation of financial statements in compliance with GAAP requires the application of accounting policies, as well as the use of estimates, assumptions, and judgments that could have a material impact on our financial statements and related disclosures. Judgments regarding future events may include the likelihood of success of particular projects, legal and regulatory challenges, and anticipated recovery of costs. Actual results may differ significantly from estimated amounts based on varying assumptions.

Our significant accounting policies are described in Note 1, Summary of Significant Accounting Policies. The following is a list of accounting policies and estimates that require management's most difficult, subjective, or complex judgments and may change in subsequent periods.

Regulatory Accounting

Our utility operations follow the guidance under the Regulated Operations Topic of the FASB ASC (Topic 980). Our financial statements reflect the effects of the ratemaking principles followed by the various jurisdictions regulating us. Certain items that would otherwise be immediately recognized as revenues and expenses are deferred as regulatory assets and regulatory liabilities for future recovery or refund to customers, as authorized by our regulators.

Future recovery of regulatory assets, including the timeliness of recovery and our ability to earn a reasonable return, is not assured and is generally subject to review by regulators in rate proceedings for matters such as prudence and reasonableness. Once approved, the regulatory assets and liabilities are amortized into earnings over the rate recovery or refund period. If recovery or refund of costs is not approved or is no longer considered probable, these regulatory assets or liabilities are recognized in current period earnings. Management regularly assesses whether these regulatory assets and liabilities are probable of future recovery or refund by considering factors such as changes in the regulatory environment, earnings from our electric and natural gas utility operations, rate orders issued by our regulators, historical decisions by our regulators regarding regulatory assets and liabilities, and the status of any pending or potential deregulation legislation.

The application of the Regulated Operations Topic of the FASB ASC would be discontinued if all or a separable portion of our utility operations no longer met the criteria for application. Our regulatory assets and liabilities would be written off to income as an unusual or infrequently occurring item in the period in which discontinuation occurred. See Note 6, Regulatory Assets and Liabilities, for more information on our regulatory assets and liabilities.

Goodwill

We completed our annual goodwill impairment tests for all of our reporting units that carried a goodwill balance as of July 1, 2023. No impairments were recorded as a result of these tests. For all of our reporting units, the fair values calculated in step one of the test were greater than their carrying values. The fair values for the reporting units were calculated using a combination of the income approach and the market approach.

For the income approach, we used internal forecasts to project cash flows. Any forecast contains a degree of uncertainty, and changes in these cash flows could significantly increase or decrease the calculated fair value of a reporting unit. For our reporting units that are regulated, a fair recovery of and return on costs prudently incurred to serve customers is assumed. An unfavorable outcome in a rate case could cause the fair values of our reporting units to decrease.

Key assumptions used in the income approach include ROEs, the long-term growth rates used to determine terminal values at the end of the discrete forecast period, and the discount rates. The discount rate is applied to estimated future cash flows and is one of the most significant assumptions used to determine fair value under the income approach. As interest rates rise, the calculated fair values will decrease. The discount rate is based on the weighted-average cost of capital for each reporting unit, taking into account both the after-tax cost of debt and cost of equity. The terminal year ROE for each utility is driven by its current allowed ROE. The terminal growth rate is based primarily on a combination of historical and forecasted statistics for real gross domestic product and personal income for each utility service area.

For the market approach, we used a higher weighting for the guideline public company method than the guideline merged and acquired company method due to a low number of mergers and acquisitions in recent years. The guideline public company method uses financial metrics from similar publicly traded companies to determine fair value. The guideline merged and acquired company method calculates fair value by analyzing the actual prices paid for recent mergers and acquisitions in the industry. We applied multiples derived from these two methods to the appropriate operating metrics for our reporting units to determine fair value.

The underlying assumptions and estimates used in the impairment tests were made as of a point in time. Subsequent changes in these assumptions and estimates could change the results of the tests.

For all of our reporting units that carried a goodwill balance at July 1, 2023, the fair value exceeded its carrying value by over 50%. Based on these results, our reporting units are not at risk of failing step one of the goodwill impairment test.

See Note 10, Goodwill and Intangibles, for more information.

Long-Lived Assets

In accordance with ASC 980-360, Regulated Operations – Property, Plant, and Equipment, we periodically assess the recoverability of certain long-lived assets when events or changes in circumstances indicate that the carrying amount of those long-lived assets may not be recoverable. Examples of events or changes in circumstances include, but are not limited to, a significant decrease in the market price, a significant change in use, a regulatory decision related to recovery of assets from customers, adverse legal factors or a change in business climate, operating or cash flow losses, or an expectation that the asset might be sold or abandoned. See Note 1(k), Asset Impairment, for our policy on accounting for abandonments and recently completed plant subject to disallowance.

Performing an impairment evaluation involves a significant degree of estimation and judgment by management in areas such as identifying circumstances that indicate an impairment may exist, identifying and grouping affected assets, and developing the undiscounted future cash flows. An impairment loss is measured as the excess of the carrying amount of the asset in comparison to the fair value of the asset. The fair value of the asset is assessed using various methods, including recent comparable third-party sales for our nonregulated operations, internally developed discounted cash flow analysis, expected recovery of regulated assets, and analysis from outside advisors.

See Note 7, Property, Plant, and Equipment, for more information on our generating units probable of being retired. See Note 6, Regulatory Assets and Liabilities, and Note 26, Regulatory Environment, for more information on our retired generating units, including various approvals we received from the FERC and the PSCW.

Pension and Other Postretirement Employee Benefits

The costs of providing non-contributory defined pension benefits and OPEB, described in Note 20, Employee Benefits, are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

Pension and OPEB costs are impacted by actual employee demographics (including age, compensation levels, and employment periods), the level of contributions made to the plans, and earnings on plan assets. Pension and OPEB costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets, mortality and discount rates, and expected health care cost trends. Changes made to the plan provisions may also impact current and future pension and OPEB costs.

Pension and OPEB plan assets are primarily made up of equity and fixed income investments. Fluctuations in actual equity and fixed income market returns, as well as changes in general interest rates, may result in increased or decreased benefit costs in future periods. Changes in benefit costs are mitigated at our Wisconsin utilities through the requirement that WE, WPS, and WG implement escrow accounting treatment for pension and OPEB costs in 2023 and 2024, as required by the December 2022 rate orders issued by the PSCW. See Note 26, Regulatory Environment, for more information on 2023 and 2024 rates at our Wisconsin utilities. We believe that changes to benefit costs at our other utilities would be recovered or refunded through the ratemaking process.

The following table shows how a given change in certain actuarial assumptions would impact the projected benefit obligation and the reported net periodic pension cost (including amounts capitalized to our balance sheets). Each factor below reflects an evaluation of the change based on a change in that assumption only.

Actuarial Assumption (in millions, except percentages)	**Percentage-Point Change in Assumption**	**Impact on Projected Benefit Obligation**	**Impact on 2023 Pension Cost**
Discount rate	(0.5)	$ 114.7	$ 5.3
Discount rate	0.5	(106.9)	(10.2)
Rate of return on plan assets	(0.5)	N/A	14.1
Rate of return on plan assets	0.5	N/A	(14.1)

The following table shows how a given change in certain actuarial assumptions would impact the accumulated OPEB obligation and the reported net periodic OPEB cost (including amounts capitalized to our balance sheets). Each factor below reflects an evaluation of the change based on a change in that assumption only.

Actuarial Assumption (in millions, except percentages)	**Percentage-Point Change in Assumption**	**Impact on Postretirement Benefit Obligation**	**Impact on 2023 Postretirement Benefit Cost**
Discount rate	(0.5)	$ 22.5	$ 2.2
Discount rate	0.5	(21.4)	(1.9)
Health care cost trend rate	(0.5)	(12.4)	(2.6)
Health care cost trend rate	0.5	13.9	2.9
Rate of return on plan assets	(0.5)	N/A	4.1
Rate of return on plan assets	0.5	N/A	(4.1)

The discount rates are selected based on hypothetical bond portfolios consisting of noncallable, high-quality corporate bonds across the full maturity spectrum. From the hypothetical bond portfolios, a single rate is determined that equates the market value of the bonds purchased to the discounted value of the plans' expected future benefit payments.

We establish our expected return on assets based on consideration of historical and projected asset class returns, as well as the target allocations of the benefit trust portfolios. The assumed long-term rate of return on pension plan assets was 6.62% in 2023 and

6.88% in 2022 and 2021. The actual rate of return on pension plan assets, net of fees, was 9.23%, (14.03)%, and 9.51%, in 2023, 2022, and 2021, respectively.

In selecting assumed health care cost trend rates, past performance and forecasts of health care costs are considered. For more information on health care cost trend rates and a table showing future payments that we expect to make for our pension and OPEB, see Note 20, Employee Benefits.

Unbilled Revenues

We record utility operating revenues when energy is delivered to our customers. However, the determination of energy sales to individual customers is based upon the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of their last meter reading are estimated and corresponding unbilled revenues are calculated.

Unbilled revenues are estimated each month based upon actual generation and throughput volumes, recorded sales, estimated customer usage by class, weather factors, estimated line losses, and applicable customer rates. Energy demand for the unbilled period or changes in rate mix due to fluctuations in usage patterns of customer classes could impact the accuracy of the unbilled revenue estimate. Total unbilled utility revenues were $473.9 million and $663.1 million as of December 31, 2023 and 2022, respectively. The changes in unbilled revenues are primarily due to changes in the cost of natural gas, weather, and customer rates.

Income Tax Expense

Significant management judgment is required in determining our provision for income taxes, deferred income tax assets and liabilities, the liability for unrecognized tax benefits, and any valuation allowance recorded against deferred income tax assets. The assumptions involved are supported by historical data, reasonable projections, and interpretations of applicable tax laws and regulations across multiple taxing jurisdictions. Significant changes in these assumptions could have a material impact on our financial condition and results of operations. See Note 1(q), Income Taxes, and Note 16, Income Taxes, for a discussion of accounting for income taxes.

We are required to estimate income taxes for each of our applicable tax jurisdictions as part of the process of preparing consolidated financial statements. This process involves estimating current income tax liabilities together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for income tax and accounting purposes. These differences result in deferred income tax assets and liabilities, which are included within our balance sheets. We also assess the likelihood that our deferred income tax assets will be recovered through future taxable income. To the extent we believe that realization is not likely, we establish a valuation allowance, which is offset by an adjustment to income tax expense in our income statements.

Uncertainty associated with the application of tax statutes and regulations, the outcomes of tax audits and appeals, changes in income tax law, enacted tax rates or amounts subject to income tax, and changes in the regulatory treatment of any tax reform benefits requires that judgments and estimates be made in the accrual process and in the calculation of effective tax rates. Only income tax benefits that meet the "more likely than not" recognition threshold may be recognized or continue to be recognized. Unrecognized tax benefits are re-evaluated quarterly and changes are recorded based on new information, including the issuance of relevant guidance by the courts or tax authorities and developments occurring in the examinations of our tax returns.

We expect our 2024 annual effective tax rate to be between 11.5% and 12.5%. Our effective tax rate calculations are revised every quarter based on the best available year-end tax assumptions, adjusted in the following year after returns are filed. Tax accrual estimates are trued-up to the actual amounts claimed on the tax returns and further adjusted after examinations by taxing authorities, as needed.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity, and Capital Resources – Market Risks and Other Significant Risks, as well as Note 1(r), Fair Value Measurements, Note 1(s), Derivative Instruments, and Note 19, Guarantees, for information concerning potential market risks to which we are exposed.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

A. REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of WEC Energy Group, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of WEC Energy Group, Inc. and subsidiaries (the "Company") as of December 31, 2023 and 2022, the related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2023, and the related notes and the schedules listed in the Index at Item 15 (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 22, 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.

Regulatory Assets and Liabilities - Impact of rate regulation on financial statements — Refer to Notes 6 and 26 to the financial statements

Critical Audit Matter Description

The Company’s regulated utilities are subject to regulation by various state and federal regulatory bodies (collectively the “Commissions”) which have jurisdiction with respect to the rates of electric and gas distribution companies in each respective state. Management has determined the Company meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the Regulated Operations Topic of the Financial Accounting Standards Board’s Accounting Standard Codification.

Rates are determined and approved in regulatory proceedings based on an analysis of the Company's costs to provide utility service and a return on, and recovery of, the Company's investment in the utility business. Current and future regulatory decisions can have an impact on the recovery of costs, the rate of return earned on investment, and the timing and amount of assets to be recovered through rates. The Commissions' regulation of rates is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital. Certain items that would otherwise be immediately recognized as revenues and expenses are deferred as regulatory assets and regulatory liabilities for future recovery or refund to customers, as authorized by the Company's regulators. While the Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that the Commissions will not approve: (1) full recovery of the costs of providing utility service, (2) full recovery of all amounts invested in the utility business and a reasonable return on that investment or (3) timely recovery of costs incurred.

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the subjectivity involved in assessing the impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs and/or (2) a refund to customers. Auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the impact of rate regulation on certain assets and liabilities included the following, among others:

- We tested the effectiveness of management's controls over regulatory assets and liabilities, including management's controls over the identification of costs recorded as regulatory assets and liabilities and the monitoring and evaluation of regulatory developments that may affect the likelihood of recovering costs in future rates.

- We inquired of Company management and independently obtained and read: (1) relevant regulatory orders issued by the Commissions for the Company, (2) Company filings with the Commissions, (3) filings made by intervenors and (4) other publicly available information to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions' treatment of similar costs under similar circumstances. To assess completeness, we evaluated the information obtained and compared it to management's recorded regulatory asset and liability balances.

- For regulatory matters in process, we inspected the Company's filings with the Commissions and the filings with the Commissions by intervenors that may impact the Company's future rates, for any evidence that might contradict management's assertions.

- We evaluated management's analysis regarding probability of recovery for regulatory assets or refund or future reduction in rates for regulatory liabilities not yet addressed in a regulatory order to assess management's assertion that amounts are probable of recovery or a future reduction in rates.

- We evaluated the Company’s disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.

/s/DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
February 22, 2024

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

A. REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of WEC Energy Group, Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of WEC Energy Group, Inc. 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 and financial statement schedules as of and for the year ended December 31, 2023, of the Company and our report dated February 22, 2024, expressed an unqualified opinion on those consolidated financial statements and financial statement schedules.

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 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

Milwaukee, Wisconsin
February 22, 2024

B. CONSOLIDATED INCOME STATEMENTS

Year Ended December 31 (in millions, except per share amounts)	2023	2022	2021
Operating revenues	**$ 8,893.0**	$ 9,597.4	$ 8,316.0
Operating expenses			
Cost of sales	**3,191.2**	4,358.9	3,311.0
Other operation and maintenance	**2,100.5**	1,938.0	2,005.5
Impairment related to ICC disallowances	**178.9**	—	—
Depreciation and amortization	**1,264.2**	1,122.6	1,074.3
Property and revenue taxes	**250.2**	253.7	210.3
Total operating expenses	**6,985.0**	7,673.2	6,601.1
Operating income	**1,908.0**	1,924.2	1,714.9
Equity in earnings of transmission affiliates	**177.5**	194.7	158.1
Other income, net	**177.7**	128.8	133.2
Interest expense	**726.9**	515.1	471.1
Loss on debt extinguishment	**—**	—	36.3
Other expense	**(371.7)**	(191.6)	(216.1)
Income before income taxes	**1,536.3**	1,732.6	1,498.8
Income tax expense	**204.6**	322.9	200.3
Net income	**1,331.7**	1,409.7	1,298.5
Preferred stock dividends of subsidiary	**1.2**	1.2	1.2
Net (income) loss attributed to noncontrolling interests	**1.2**	(0.4)	3.0
Net income attributed to common shareholders	**$ 1,331.7**	$ 1,408.1	$ 1,300.3
Earnings per share			
Basic	**$ 4.22**	$ 4.46	$ 4.12
Diluted	**$ 4.22**	$ 4.45	$ 4.11
Weighted average common shares outstanding			
Basic	**315.4**	315.4	315.4
Diluted	**315.9**	316.1	316.3

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

C. CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31 (in millions)		2023		2022		2021
Net income	**$**	**1,331.7**	$	1,409.7	$	1,298.5
Other comprehensive income (loss), net of tax						
Derivatives accounted for as cash flow hedges						
Net derivative gain, net of tax		**—**		—		0.6
Reclassification of realized net derivative (gain) loss to net income, net of tax		**(0.3)**		(0.3)		0.9
Cash flow hedges, net		**(0.3)**		(0.3)		1.5
Defined benefit plans						
Pension and OPEB adjustments arising during the period, net of tax expense (benefit) of $(0.2), $(1.3), and $0.7, respectively		**(0.6)**		(3.5)		1.7
Amortization of pension and OPEB costs included in net periodic benefit cost, net of tax		**—**		0.2		0.4
Defined benefit plans, net		**(0.6)**		(3.3)		2.1
Other comprehensive income (loss), net of tax		**(0.9)**		(3.6)		3.6
Comprehensive income		**1,330.8**		1,406.1		1,302.1
Preferred stock dividends of subsidiary		**1.2**		1.2		1.2
Comprehensive (income) loss attributed to noncontrolling interests		**1.2**		(0.4)		3.0
Comprehensive income attributed to common shareholders	**$**	**1,330.8**	$	1,404.5	$	1,303.9

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

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D. CONSOLIDATED BALANCE SHEETS

At December 31 (in millions, except share and per share amounts)	2023	2022
Assets		
Current assets		
Cash and cash equivalents	**$ 42.9**	$ 28.9
Accounts receivable and unbilled revenues, net of reserves of $193.5 and $199.3, respectively	**1,503.2**	1,818.4
Materials, supplies, and inventories	**775.2**	807.1
Prepaid taxes	**173.9**	201.8
Other prepayments	**76.8**	69.8
Other	**223.7**	261.7
Current assets	**2,795.7**	3,187.7
Long-term assets		
Property, plant, and equipment, net of accumulated depreciation and amortization of $11,073.1 and $10,383.8, respectively	**31,581.5**	29,113.8
Regulatory assets (December 31, 2023 and December 31, 2022 include $85.9 and $92.4, respectively, related to WEPCo Environmental Trust)	**3,249.8**	3,264.6
Equity investment in transmission affiliates	**2,005.9**	1,909.2
Goodwill	**3,052.8**	3,052.8
Pension and OPEB assets	**870.9**	916.7
Other	**383.1**	427.3
Long-term assets	**41,144.0**	38,684.4
Total assets	**$ 43,939.7**	$ 41,872.1
Liabilities and Equity		
Current liabilities		
Short-term debt	**$ 2,020.9**	$ 1,647.1
Current portion of long-term debt (December 31, 2023 and December 31, 2022 include $9.0 and $8.9, respectively, related to WEPCo Environmental Trust)	**1,264.2**	881.2
Accounts payable	**896.6**	1,198.1
Other	**933.1**	884.6
Current liabilities	**5,114.8**	4,611.0
Long-term liabilities		
Long-term debt (December 31, 2023 and December 31, 2022 include $85.3 and $94.1, respectively, related to WEPCo Environmental Trust)	**15,512.8**	14,766.2
Deferred income taxes	**4,918.5**	4,625.6
Deferred revenue, net	**356.4**	370.7
Regulatory liabilities	**3,697.7**	3,735.5
Intangible liabilities	**594.8**	335.4
Environmental remediation liabilities	**463.7**	499.6
AROs	**374.2**	479.3
Pension and OPEB obligations	**176.0**	171.6
Other	**659.3**	660.6
Long-term liabilities	**26,753.4**	25,644.5

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

E. CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31 (in millions)	2023	2022	2021
Operating activities			
Net income	**$ 1,331.7**	$ 1,409.7	$ 1,298.5
Reconciliation to cash provided by operating activities			
Depreciation and amortization	**1,264.2**	1,122.6	1,074.3
Deferred income taxes and ITCs, net	**219.4**	280.1	151.1
Impairment related to ICC disallowances	**178.9**	—	—
Contributions and payments related to pension and OPEB plans	**(16.7)**	(15.1)	(66.3)
Equity income in transmission affiliates, net of distributions	**(33.0)**	(74.3)	(25.1)
Net change in transmission regulatory assets and liabilities	**19.8**	(85.8)	5.7
Net gain on disposition of assets	**(23.8)**	(66.2)	(6.2)
Change in –			
Accounts receivable and unbilled revenues, net	**340.6**	(342.1)	(249.2)
Materials, supplies, and inventories	**41.9**	(171.3)	(107.2)
Amounts recoverable from customers	**17.4**	60.0	(82.3)
Collateral on deposit	**22.1**	(108.1)	4.6
Other current assets	**18.9**	(27.7)	17.6
Accounts payable	**(254.0)**	121.5	126.9
Other current liabilities	**47.5**	126.9	(17.2)
Other, net	**(156.5)**	(169.5)	(92.5)
Net cash provided by operating activities	**3,018.4**	2,060.7	2,032.7
Investing activities			
Capital expenditures	**(2,492.9)**	(2,314.9)	(2,252.8)
Acquisition of Whitewater	**(76.0)**	—	—
Acquisition of Sapphire Sky, net of cash acquired of $0.3	**(442.6)**	—	—
Acquisition of Samson I, net of cash acquired of $5.2	**(257.3)**	—	—
Acquisition of Red Barn	**(143.8)**	—	—
Acquisition of West Riverside	**(95.3)**	—	—
Acquisition of Thunderhead, net of cash acquired of $0.5	**—**	(382.0)	—
Acquisition of Jayhawk	**—**	—	(119.9)
Capital contributions to transmission affiliates	**(63.7)**	(45.5)	—
Proceeds from the sale of assets	**32.8**	69.0	21.9
Proceeds from the sale of investments held in rabbi trust	**10.4**	15.4	18.7
Payments for ATC's construction costs that will be reimbursed	**(19.8)**	(24.8)	(7.0)
Reimbursement for ATC's construction costs	**0.1**	10.2	—
Insurance proceeds received for property damage	**2.5**	41.6	—
Other, net	**(12.6)**	(11.4)	27.3
Net cash used in investing activities	**(3,558.2)**	(2,642.4)	(2,311.8)

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

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F. CONSOLIDATED STATEMENTS OF EQUITY

WEC Energy Group Common Shareholders' Equity								
(in millions, except per share amounts)	**Common Stock**	**Additional Paid In Capital**	**Retained Earnings**	**Accumulated Other Comprehensive Income (Loss)**	**Total Common Shareholders' Equity**	**Preferred Stock of Subsidiary**	**Non-controlling Interests**	
Balance at December 31, 2020	$ 3.2	$ 4,143.7	$ 6,329.6	$ (6.8)	$ 10,469.7	$ 30.4	$ 162.4	$
Net income attributed to common shareholders	—	—	1,300.3	—	1,300.3	—	—	
Net loss attributed to noncontrolling interests	—	—	—	—	—	—	(3.0)	
Other comprehensive income	—	—	—	3.6	3.6	—	—	
Common stock dividends of $2.71 per share	—	—	(854.8)	—	(854.8)	—	—	
Exercise of stock options	—	15.7	—	—	15.7	—	—	
Purchase of common stock	—	(33.1)	—	—	(33.1)	—	—	
Acquisition of noncontrolling interests	—	—	—	—	—	—	6.3	
Capital contributions from noncontrolling interest	—	—	—	—	—	—	7.6	
Distributions to noncontrolling interests	—	—	—	—	—	—	(4.1)	
Stock-based compensation and other	—	11.8	—	—	11.8	—	0.5	
Balance at December 31, 2021	$ 3.2	$ 4,138.1	$ 6,775.1	$ (3.2)	$ 10,913.2	$ 30.4	$ 169.7	$
Net income attributed to common shareholders	—	—	1,408.1	—	1,408.1	—	—	
Net income attributed to								

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

G. NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Nature of Operations—WEC Energy Group serves approximately 1.7 million electric customers and 3.0 million natural gas customers, owns approximately 60% of ATC, and owns majority interests in multiple renewable generating facilities as part of its non-utility energy infrastructure segment.

As used in these notes, the term "financial statements" refers to the consolidated financial statements. This includes the income statements, statements of comprehensive income, balance sheets, statements of cash flows, and statements of equity, unless otherwise noted. On our financial statements, we consolidate our majority-owned subsidiaries, which we control, and VIEs, of which we are the primary beneficiary. We reflect noncontrolling interests for the portion of entities that we do not own as a component of consolidated equity separate from the equity attributable to our shareholders. The noncontrolling interests that we reported as equity on our balance sheet as of December 31, 2023 related to the minority interests held by third parties in the renewable generating facilities that are included in our non-utility energy infrastructure segment.

Our financial statements include the accounts of WEC Energy Group, a diversified energy holding company, and the accounts of our subsidiaries in the following reportable segments:

- Wisconsin segment – Consists of WE, WPS, and WG, which are engaged primarily in the generation of electricity and the distribution of electricity and natural gas in Wisconsin; and UMERC, which generates electricity and distributes electricity and natural gas to customers located in the Upper Peninsula of Michigan.

- Illinois segment – Consists of PGL and NSG, which are engaged primarily in the distribution of natural gas in Illinois.

- Other states segment – Consists of MERC and MGU, which are engaged primarily in the distribution of natural gas in Minnesota and Michigan, respectively.

- Electric transmission segment – Consists of our approximate 60% ownership interest in ATC, a for-profit, electric transmission company regulated by the FERC and certain state regulatory commissions, and our approximate 75% ownership interest in ATC Holdco, which invests in transmission-related projects outside of ATC's traditional footprint.

- Non-utility energy infrastructure segment – Consists of We Power, which is principally engaged in the ownership of electric power generating facilities for long-term lease to WE, and Bluewater, which owns underground natural gas storage facilities in Michigan. WECI, which holds our majority interests in multiple renewable generating facilities, is also included in this segment. See Note 2, Acquisitions, for more information on recently acquired WECI renewable generating facilities.

- Corporate and other segment – Consists of the WEC Energy Group holding company, the Integrys holding company, the PELLC holding company, Wispark, Wisvest, WECC, and WBS.

Investments in companies not controlled by us, but over which we have significant influence regarding the operating and financial policies of the investee, are accounted for using the equity method. We use the cumulative earnings approach for classifying distributions received in the statements of cash flows. Under the cumulative earnings approach, we compare the distributions received to cumulative equity method earnings since inception. Any distributions received up to the amount of cumulative equity earnings are considered a return on investment and classified in operating activities. Any excess distributions are considered a return of investment and classified in investing activities.

Our financial statements also reflect our proportionate interests in certain jointly owned utility facilities. See Note 8, Jointly Owned Utility Facilities, for more information.

(b) Basis of Presentation—We prepare our financial statements in conformity with GAAP. We make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results may differ from these estimates.

(c) Cash and Cash Equivalents—Cash and cash equivalents include marketable debt securities with an original maturity of three months or less.

(d) Operating Revenues—The following discussion includes our significant accounting policies related to operating revenues. For additional required disclosures on disaggregation of operating revenues, see Note 4, Operating Revenues.

Revenues from Contracts with Customers

Electric Utility Operating Revenues

Electricity sales to residential and commercial and industrial customers are generally accomplished through requirements contracts, which provide for the delivery of as much electricity as the customer needs. These contracts represent discrete deliveries of electricity and consist of one distinct performance obligation satisfied over time, as the electricity is delivered and consumed by the customer simultaneously. For our Wisconsin residential and commercial and industrial customers and the majority of our Michigan residential and commercial and industrial customers, our performance obligation is bundled to consist of both the sale and the delivery of the electric commodity. In our Michigan service territory, a limited number of residential and commercial and industrial customers can purchase the commodity from a third party. In this case, the delivery of the electricity represents our sole performance obligation.

The transaction price of the performance obligations for residential and commercial and industrial customers is valued using the rates, charges, terms, and conditions of service included in the tariffs of our regulated electric utilities, which have been approved by state regulators. These rates often have a fixed component customer charge and a usage-based variable component charge. We recognize revenue for the fixed component customer charge monthly using a time-based output method. We recognize revenue for the usage-based variable component charge using an output method based on the quantity of electricity delivered each month. Our retail electric rates in Wisconsin include base amounts for fuel and purchased power costs, which also impact our revenues. The electric fuel rules set by the PSCW allow us to defer, for subsequent rate recovery or refund, under- or over-collections of actual fuel and purchased power costs beyond a 2% price variance from the costs included in the rates charged to customers. Our electric utilities monitor the deferral of under-collected costs to ensure that it does not cause them to earn a greater ROE than authorized by the PSCW. In contrast, the rates of our Michigan retail electric customers include recovery of fuel and purchased power costs on a one-for-one basis. In addition, the Wisconsin residential tariffs of WE and WPS include a mechanism for cost recovery or refund of uncollectible expense based on the difference between actual uncollectible write-offs and the amounts recovered in rates.

Wholesale customers who resell power can choose to either bundle capacity and electricity services together under one contract with a supplier or purchase capacity and electricity separately from multiple suppliers. Furthermore, wholesale customers can choose to have our utilities provide generation to match the customer's load, similar to requirements contracts, or they can purchase specified quantities of electricity and capacity. Contracts with wholesale customers that include capacity bundled with the delivery of electricity contain two performance obligations, as capacity and electricity are often transacted separately in the marketplace at the wholesale level. When recognizing revenue associated with these contracts, the transaction price is allocated to each performance obligation based on its relative standalone selling price. Revenue is recognized as control of each individual component is transferred to the customer. Electricity is the primary product sold by our electric utilities and represents a single performance obligation satisfied over time through discrete deliveries to a customer. Revenue from electricity sales is generally recognized as units are produced and delivered to the customer within the production month. Capacity represents the reservation of an electric generating facility and conveys the ability to call on a plant to produce electricity when needed by the customer. The nature of our performance obligation as it relates to capacity is to stand ready to deliver power. This represents a single performance obligation transferred over time, which generally represents a monthly obligation. Accordingly, capacity revenue is recognized on a monthly basis.

The transaction price of the performance obligations for wholesale customers is valued using the rates, charges, terms, and conditions of service, which have been approved by the FERC. These wholesale rates include recovery of fuel and purchased power costs from customers on a one-for-one basis. For the majority of our wholesale customers, the price billed for energy and capacity is a formula-based rate. Formula-based rates initially set a customer's current year rates based on the previous year’s expenses. This is a predetermined formula derived from the utility's costs and a reasonable rate of return. Because these rates are eventually trued up to reflect actual current-year costs, they represent a form of variable consideration in certain circumstances. The variable consideration is estimated and recognized over time as wholesale customers receive and consume the capacity and electricity services.

We are an active participant in the MISO Energy Markets, where we bid our generation into the Day Ahead and Real Time markets and procure electricity for our retail and wholesale customers at prices determined by the MISO Energy Markets. Purchase and sale transactions are recorded using settlement information provided by MISO. These purchase and sale transactions are accounted for on a net hourly position. Net purchases in a single hour are recorded as purchased power in cost of sales, and net sales in a single hour are recorded as resale revenues on our income statements. For resale revenues, our performance obligation is created only when electricity is sold into the MISO Energy Markets.

For all of our customers, consistent with the timing of when we recognize revenue, customer billings generally occur on a monthly basis, with payments typically due in full within 30 days.

Natural Gas Utility Operating Revenues

We recognize natural gas utility operating revenues under requirements contracts with residential, commercial and industrial, and transportation customers served under the tariffs of our regulated utilities. Tariffs provide our customers with the standard terms and conditions, including rates, related to the services offered. Requirements contracts provide for the delivery of as much natural gas as the customer needs. These requirements contracts represent discrete deliveries of natural gas and constitute a single performance obligation satisfied over time. Our performance obligation is both created and satisfied with the transfer of control of natural gas upon delivery to the customer. For most of our customers, natural gas is delivered and consumed by the customer simultaneously. A performance obligation can be bundled to consist of both the sale and the delivery of the natural gas commodity. In certain of our service territories, customers can purchase the commodity from a third party. In this case, the performance obligation only includes the delivery of the natural gas to the customer.

The transaction price of the performance obligations for our natural gas customers is valued using the rates, charges, terms, and conditions of service included in the tariffs of our regulated utilities, which have been approved by state regulators. These rates often have a fixed component customer charge and a usage-based variable component charge. We recognize revenue for the fixed component customer charge monthly using a time-based output method. We recognize revenue for the usage-based variable component charge using an output method based on natural gas delivered each month.

The tariffs of our natural gas utilities include various rate mechanisms that allow them to recover or refund changes in prudently incurred costs from rate case-approved amounts. The rates for all of our natural gas utilities include one-for-one recovery mechanisms for natural gas commodity costs. Under normal circumstances, we defer any difference between actual natural gas costs incurred and costs recovered through rates as a current asset or liability. The deferred balance is returned to or recovered from customers at intervals throughout the year. However, as a result of the extreme weather in the Midwest in February 2021, the cost of gas purchased for our natural gas customers was temporarily driven significantly higher than our normal winter weather expectations, and we were not allowed to recover all of the additional costs. See Note 26, Regulatory Environment, for more information on the recovery of these high natural gas costs.

In addition, the rates of PGL and NSG, and the residential tariffs of WE, WPS, and WG, include riders or other mechanisms for cost recovery or refund of uncollectible expense based on the difference between actual uncollectible write-offs and the amounts recovered in rates. The rates of PGL and NSG include riders for cost recovery of both environmental cleanup costs and energy conservation and management program costs. Finally, through the end of 2023, PGL's rates included a rider for pass through of income tax expense changes resulting from the Tax Legislation and a cost recovery mechanism for SMP costs. Similarly, the rates of MGU include a rider to recover costs incurred to replace or modify natural gas facilities.

Consistent with the timing of when we recognize revenue, customer billings generally occur on a monthly basis, with payments typically due in full within 30 days.

Other Natural Gas Operating Revenues

We have other natural gas operating revenues from Bluewater, which is in our non-utility energy infrastructure segment. Bluewater has entered into long-term service agreements for natural gas storage services with WE, WPS, and WG, and also provides limited service to unaffiliated customers. We recognize revenues using a time-based output method through a monthly fixed service fee. Typical storage contract rates consist of firm storage reservation charges and firm injection and withdrawal charges. All amounts associated with the service agreements with WE, WPS, and WG have been eliminated at the consolidated level.

Other Non-Utility Operating Revenues

Wind and solar generation revenues from WECI's ownership interests in renewable generation facilities continued to grow in 2023. See Note 2, Acquisitions, for more information on recent acquisitions. Most of these renewable generation facilities have offtake agreements with unaffiliated third parties for all of the energy to be produced by the facility, some of which are bundled with capacity and RECs. We consider bundled energy, capacity, and RECs within these offtake agreements to be distinct performance obligations as each are often transacted separately in the marketplace.

When recognizing revenue associated with these contracts, the transaction price is allocated to each performance obligation based on its relative standalone selling price. Revenue is recognized as control of each individual component is transferred to the customer. Revenue from the sale of this renewable energy is generally recognized as units are produced and delivered to the customer within the production month. Capacity represents the reservation of the renewable generation facility and conveys the ability to call on the renewable generation facility to produce electricity when needed by the customer. The nature of our performance obligation as it relates to capacity is to stand ready to deliver power. This represents a single performance obligation transferred over time, which generally represents a monthly obligation. Accordingly, capacity revenue is recognized on a monthly basis. The performance obligation for RECs is recognized at a point-in-time; however, the timing of revenue recognition is the same, as the generation of renewable energy and the recognition of REC revenues generally occur concurrently.

Non-utility operating revenues are also derived from servicing appliances for customers at MERC. These contracts customarily have a duration of one year or less and consist of a single performance obligation satisfied over time. We use a time-based output method to recognize revenues monthly for the service fee.

Consistent with the timing of when we recognize revenue, customer billings for the renewable generation and servicing revenues generally occur on a monthly basis, with payments typically due in full within 30 days.

As part of the construction of the We Power electric generating units, we capitalized interest during construction, which is included in property, plant, and equipment. As allowed by the PSCW, we collected these carrying costs from WE's utility customers during construction. The equity portion of these carrying costs was recorded as a contract liability, which is presented as deferred revenue, net on our balance sheets. We continually amortize the deferred carrying costs to revenues over the related lease term that We Power has with WE. During 2023, 2022, and 2021, we recorded $23.5 million, $23.4 million, and $23.3 million, respectively, of revenues related to these deferred carrying costs.

Other Operating Revenues

Alternative Revenues

Alternative revenues are created from programs authorized by regulators that allow our utilities to record additional revenues by adjusting rates in the future, usually as a surcharge applied to future billings, in response to past activities or completed events. Alternative revenue programs allow compensation for the effects of weather abnormalities, other external factors, or demand side management initiatives. Alternative revenue programs can also provide incentive awards if the utility achieves certain objectives and in other limited circumstances. We record alternative revenues when the regulator-specified conditions for recognition have been met. We reverse these alternative revenues as the customer is billed, at which time this revenue is presented as revenues from contracts with customers.

Below is a summary of the alternative revenue programs at our utilities:

- The rates of PGL, NSG, and MERC include decoupling mechanisms. These mechanisms differ by state and allow the utilities to recover or refund the differences between actual and authorized margins for certain customer classes.
- MERC’s rates include a conservation improvement program rider, which includes a financial incentive for meeting energy savings goals.
- WE and WPS provide wholesale electric service to customers under market-based rates and FERC formula rates. The customer is charged a base rate each year based upon a formula using prior year actual costs and customer demand. A true-up is calculated based on the difference between the amount billed to customers for the demand component of their rates and what the actual cost of service was for the year. The true-up can result in an amount that we will recover from or refund to the customer. We consider the true-up portion of the wholesale electric revenues to be alternative revenues.

(e) Credit Losses—The following discussion includes our significant accounting policies related to credit losses. For additional required disclosures on credit losses, see Note 5, Credit Losses.

Our exposure to credit losses is related to our accounts receivable and unbilled revenue balances, which are primarily generated from the sale of electricity and natural gas by our regulated utility operations. Credit losses associated with our utility operations are analyzed at the reportable segment level as we believe contract terms, political and economic risks, and the regulatory environment are similar at this level as our reportable segments are generally based on the geographic location of the underlying utility operations.

We have an accounts receivable and unbilled revenue balance associated with our non-utility energy infrastructure segment, related to the sale of electricity from our majority-owned renewable generating facilities through agreements with several large high credit quality counterparties.

We evaluate the collectability of our accounts receivable and unbilled revenue balances considering a combination of factors. For some of our larger customers and also in circumstances where we become aware of a specific customer's inability to meet its financial obligations to us, we record a specific allowance for credit losses against amounts due in order to reduce the net recognized receivable to the amount we reasonably believe will be collected. For all other customers, we use the accounts receivable aging method to calculate an allowance for credit losses. Using this method, we classify accounts receivable into different aging buckets and calculate a reserve percentage for each aging bucket based upon historical loss rates. The calculated reserve percentages are updated on at least an annual basis, in order to ensure recent macroeconomic, political, and regulatory trends are captured in the calculation, to the extent possible. Risks identified that we do not believe are reflected in the calculated reserve percentages, are assessed on a quarterly basis to determine whether further adjustments are required.

We monitor our ongoing credit exposure through active review of counterparty accounts receivable balances against contract terms and due dates. Our activities include timely account reconciliation, dispute resolution and payment confirmation. To the extent possible, we work with customers with past due balances to negotiate payment plans, but will disconnect customers for non-payment as allowed by our regulators, if necessary, and employ collection agencies and legal counsel to pursue recovery of defaulted receivables. For our larger customers, detailed credit review procedures may be performed in advance of any sales being made. We sometimes require letters of credit, parental guarantees, prepayments or other forms of credit assurance from our larger customers to mitigate credit risk.

(f) Materials, Supplies, and Inventories—Our inventories as of December 31 consisted of:

(in millions)	**2023**	**2022**
Natural gas in storage	**$ 327.8**	$ 446.3
Materials and supplies	**320.0**	257.0
Fossil fuel	**127.4**	103.8
Total	**$ 775.2**	$ 807.1

PGL and NSG price natural gas storage injections at the calendar year average of the costs of natural gas supply purchased. Withdrawals from storage are priced on the LIFO cost method. Inventories stated on a LIFO basis represented approximately 17% and 13% of total inventories at December 31, 2023 and 2022, respectively. The estimated replacement cost of natural gas in inventory at December 31, 2023 and 2022, exceeded the LIFO cost by $12.2 million and $98.3 million, respectively. In calculating these replacement amounts, PGL and NSG used a Chicago city-gate natural gas price per Dth of $2.13 at December 31, 2023, and $3.41 at December 31, 2022.

Substantially all other natural gas in storage, materials and supplies, and fossil fuel inventories are recorded using the weighted-average cost method of accounting.

(g) Regulatory Assets and Liabilities—The economic effects of regulation can result in regulated companies recording costs and revenues that are allowed in the ratemaking process in a period different from the period they would have been recognized by a nonregulated company. When this occurs, regulatory assets and regulatory liabilities are recorded on the balance sheet. Regulatory assets represent deferred costs probable of recovery from customers that would have otherwise been charged to expense. Regulatory liabilities represent amounts that are expected to be refunded to customers in future rates or future costs already collected from customers in rates.

The recovery or refund of regulatory assets and liabilities is based on specific periods determined by our regulators or occurs over the normal operating period of the related assets and liabilities. If a previously recorded regulatory asset is no longer probable of recovery, the regulatory asset is reduced to the amount considered probable of recovery, and the reduction is charged to expense in the current period. See Note 6, Regulatory Assets and Liabilities, for more information.

(h) Property, Plant, and Equipment—We record property, plant, and equipment at cost. Cost includes material, labor, overhead, and both debt and equity components of AFUDC. Additions to and significant replacements of property are charged to property, plant, and equipment at cost; minor items are charged to other operation and maintenance expense. The cost of depreciable utility property less salvage value is charged to accumulated depreciation when property is retired.

We record straight-line depreciation expense over the estimated useful life of utility property using depreciation rates approved by the applicable regulators. Annual utility composite depreciation rates are shown below:

Annual Utility Composite Depreciation Rates	**2023**	**2022**	**2021**
WE	**3.03%**	3.06%	3.09%
WPS	**2.93%**	2.67%	2.66%
WG	**2.61%**	2.47%	2.44%
PGL	**3.13%**	3.13%	3.12%
NSG	**2.46%**	2.43%	2.52%
MERC	**2.60%**	2.56%	2.58%
MGU	**2.73%**	2.75%	2.70%
UMERC	**2.97%**	3.01%	2.94%

We depreciate our We Power assets over the estimated useful life of the various property components. The components have useful lives of between 10 to 45 years for PWGS 1 and PWGS 2 and 10 to 55 years for ER 1 and ER 2.

We depreciate our WECI assets over the estimated useful life of the property, with wind and solar generating facilities being depreciated over 30 and 35 years, respectively.

We capitalize certain costs related to software developed or obtained for internal use and record these costs to amortization expense over the estimated useful life of the related software, which ranges from 3 to 15 years. If software is retired prior to being fully amortized, the difference is recorded as a loss on the income statement.

Third parties reimburse the utilities for all or a portion of expenditures for certain capital projects. Such contributions in aid of construction costs are recorded as a reduction to property, plant, and equipment.

See Note 7, Property, Plant, and Equipment, for more information.

(i) Allowance for Funds Used During Construction—AFUDC is included in utility plant accounts and represents the cost of borrowed funds (AFUDC-Debt) used during plant construction, and a return on shareholders' capital (AFUDC-Equity) used for construction purposes. AFUDC-Debt is recorded as a reduction of interest expense, and AFUDC-Equity is recorded in other income, net.

The majority of AFUDC is recorded at WE, WPS, WG, UMERC, and WBS. Approximately 50% of WE's, WPS's, WG's, UMERC's, and WBS's retail jurisdictional CWIP expenditures are subject to the AFUDC calculation. The AFUDC calculation for WBS uses the WPS AFUDC retail rate, while our utilities' AFUDC rates are determined by their respective state commissions, each with specific requirements. Average AFUDC rates are shown below:

	2023	
	Average AFUDC Retail Rate	**Average AFUDC Wholesale Rate**
WE	**8.45%**	**6.70%**
WPS	**7.46%**	**4.60%**
WG	**7.94%**	**N/A**
UMERC	**6.28%**	**N/A**
WBS	**7.46%**	**N/A**

Our regulated utilities and WBS recorded the following AFUDC for the years ended December 31:

(in millions)	2023	2022	2021
AFUDC-Debt			
WE	**$ 13.0**	$ 6.9	$ 2.9
WPS	**2.9**	2.3	3.5
WG	**3.4**	1.4	0.2
UMERC	**—**	0.1	0.1
WBS	**0.1**	0.1	0.1
Other	**0.1**	0.2	—
Total AFUDC-Debt	**$ 19.5**	$ 11.0	$ 6.8
AFUDC-Equity			
WE	**$ 41.0**	$ 18.8	$ 7.9
WPS	**7.6**	5.8	9.0
WG	**9.8**	3.9	0.6
UMERC	**—**	0.1	0.1
WBS	**0.4**	0.3	0.2
Other	**0.3**	0.5	0.2
Total AFUDC-Equity	**$ 59.1**	$ 29.4	$ 18.0

(j) Cloud Computing Hosting Arrangements that are Service Contracts—We have entered into several cloud computing arrangements that are hosted service contracts as part of projects related to the continuous transformation of technology. These projects include, among other things, a centralized repository for data to improve analytics, reporting and asset management, targeted enterprise resource planning systems, human resources management, employee scheduling, geospatial information, and customer contact systems. We present prepaid hosting fees that are service contracts in either prepayments or other long-term assets on our balance sheets and amortize them as the hosting services are received. Amortization expense, as well as the fees associated with the hosting arrangements, is recorded in other operation and maintenance expense on our income statements.

At December 31, 2023 and 2022, we had $11.3 million and $4.7 million, respectively, of capitalized implementation costs related to cloud computing arrangements that are hosted service contracts. We amortize the implementation costs on a straight-line basis over the cloud computing service arrangement term once the component of the hosted service is ready for its intended use. Accumulated amortization at December 31, 2023 and 2022, was $2.8 million and $1.5 million, respectively. Amortization expense for the years ended December 31, 2023, 2022, and 2021 was not significant. The presentation of the implementation costs, along with the related accumulated amortization, follows the prepaid hosting fees.

(k) Asset Impairment—Goodwill and other intangible assets with indefinite lives are subject to an annual impairment test. Interim impairment tests are performed when impairment indicators are present. During the third quarter of each year, we perform an annual impairment test for all of our reporting units that carried a goodwill balance. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit's net assets exceeds the reporting unit's fair value. An impairment loss is recorded as the excess of the carrying amount of the goodwill over its fair value. For our indefinite-lived intangible assets, an impairment loss is recognized when the carrying amount of an asset is not recoverable and exceeds its fair value. An impairment loss is measured as the excess of the carrying amount of the intangible assets over its fair value. No impairment losses were recorded for our indefinite-lived intangible assets during the years ended December 31, 2023, 2022, and 2021. See Note 10, Goodwill and Intangibles, for more information.

We periodically assess the recoverability of certain long-lived assets when factors indicate the carrying value of such assets may be impaired or such assets are planned to be sold. Long-lived assets that would be subject to an impairment assessment generally include any assets within regulated operations that may not be fully recovered from our customers as a result of regulatory decisions that will be made in the future, as well as assets within nonregulated operations that are proposed to be sold or are currently generating operating losses. An impairment loss is recognized when the carrying amount of an asset is not recoverable and exceeds its fair value. The carrying amount of an asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. An impairment loss is measured as the excess of the carrying amount of the asset over its fair value.

We assess the likelihood of a disallowance of part of the cost of recently completed plant by considering factors such as applicable regulatory environment changes, our own recent rate orders, as well as recent rate orders of other regulated entities in similar jurisdictions. When it becomes probable that part of the cost of recently completed plant will be disallowed for rate-making purposes, we assess whether a reasonable estimate of the amount of the disallowance can be made. The estimated amount of the probable disallowance will then be deducted from the reported cost of the plant and recognized as an impairment loss. In the fourth quarter of 2023, we recorded a non-cash impairment loss of $178.9 million related to the disallowance of certain previously incurred capital costs resulting from PGL's and NSG's November 2023 rate orders from the ICC. See Note 26, Regulatory Environment, for more information.

When it becomes probable that a generating unit will be retired before the end of its useful life, we assess whether the generating unit meets the criteria for abandonment accounting. Generating units that are considered probable of abandonment are expected to cease operations in the near term, significantly before the end of their original estimated useful lives. If a generating unit meets the applicable criteria to be considered probable of abandonment, and the unit has been abandoned, we assess the likelihood of recovery of the remaining net book value of that generating unit at the end of each reporting period. If it becomes probable that regulators will disallow full recovery as well as a return on the remaining net book value of a generating unit that is either abandoned or probable of being abandoned, an impairment loss may be required. An impairment loss would be recorded if the remaining net book value of the generating unit is greater than the present value of the amount expected to be recovered from ratepayers, using an incremental borrowing rate. See Note 6, Regulatory Assets and Liabilities, and Note 7, Property, Plant, and Equipment, for more information.

We periodically assess the recoverability of equity method investments when factors indicate the carrying amount of such assets may be impaired. Equity method investments are assessed for impairment by comparing the fair values of these investments to their carrying amounts if a fair value assessment was completed or by reviewing for the presence of impairment indicators. If an impairment exists, and it is determined to be other-than-temporary, an impairment loss is recognized equal to the amount by which the carrying amount exceeds the investment's fair value.

(l) Asset Retirement Obligations—We recognize, at fair value, legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development, and normal operation of the assets. An ARO liability is recorded, when incurred, for these obligations as long as the fair value can be reasonably estimated, even if the timing or method of settling the obligation is unknown. The associated retirement costs are capitalized as part of the related long-lived asset and are depreciated over the useful life of the asset. The ARO liabilities are accreted each period using the credit-adjusted risk-free interest rates associated with the expected settlement dates of the AROs. These rates are determined when the obligations are incurred. Subsequent changes resulting from revisions to the timing or the amount of the original estimate of undiscounted cash flows are recognized as an increase or a decrease to the carrying amount of the liability and the associated capitalized retirement costs. For our regulated entities, we recognize regulatory assets or liabilities for the timing differences between when we recover an ARO in rates and when we recognize the associated retirement costs. See Note 9, Asset Retirement Obligations, for more information.

(m) Intangible Liabilities—Our finite-lived intangible liabilities include revenue contracts, consisting of PPAs and a proxy revenue swap, in addition to interconnection agreements, which resulted from the acquisitions of renewable generation facilities by WECI in our non-utility energy infrastructure segment. Intangible liabilities are amortized on a straight-line basis over their estimated useful lives, which is the term of the agreements. Amortization of the revenue contract intangible liabilities is recorded within operating revenues in the income statements. Amortization of the interconnection agreement intangible liabilities is recorded within other operation and maintenance in the income statements. The straight-line method of amortization is used because it best reflects the pattern in which the economic benefits of the intangibles are consumed or otherwise used. The amounts and useful lives assigned to intangible liabilities assumed impact the amount and timing of future amortization.

(n) Stock-Based Compensation—In accordance with the Omnibus Stock Incentive Plan, we provide long-term incentives through our equity interests to our non-employee directors, officers, and other key employees. The plan provides for the granting of stock options, restricted stock, performance shares, and other stock-based awards. Awards may be paid in common stock, cash, or a combination thereof. In addition to those shares of common stock that were subject to awards outstanding as of May 6, 2021, when the plan was last approved by shareholders, 9.0 million shares were reserved for issuance under the plan.

We recognize stock-based compensation expense on a straight-line basis over the requisite service period. Awards classified as equity awards are measured based on their grant-date fair value. Awards classified as liability awards are recorded at fair value each reporting period. We account for forfeitures as they occur, rather than estimating potential future forfeitures and recording them over the vesting period.

Stock Options

We grant non-qualified stock options that generally vest on a cliff-basis after three years. The exercise price of a stock option under the plan cannot be less than 100% of our common stock's fair market value on the grant date. Historically, all stock options have been granted with an exercise price equal to the fair market value of our common stock on the date of the grant. Options vest immediately upon retirement, death, or disability; however, they may not be exercised within six months of the grant date except in connection with certain termination of employment events following a change in control. Options expire no later than 10 years from the date of the grant.

Our stock options are classified as equity awards. The fair value of our stock options was calculated using a binomial option-pricing model. The following table shows the estimated weighted-average fair value per stock option granted along with the weighted-average assumptions used in the valuation models:

	2023	2022	2021
Stock options granted	**257,780**	437,269	530,612
Estimated weighted-average fair value per stock option	**$ 19.58**	$ 14.71	$ 13.20
Assumptions used to value the options:			
Risk-free interest rate	**3.8% – 4.8%**	0.2% – 1.6%	0.1% – 0.9%
Dividend yield	**3.2 %**	3.2 %	2.9 %
Expected volatility	**22.0 %**	21.0 %	21.0 %
Expected life (years)	**8.3**	8.7	8.7

The risk-free interest rate was based on the United States Treasury interest rate with a term consistent with the expected life of the stock options. The dividend yield was based on our dividend rate at the time of the grant and historical stock prices. Expected volatility and expected life assumptions were based on our historical experience.

Restricted Shares

Restricted shares granted to employees generally have a vesting period of three years with one-third of the award vesting on each anniversary of the grant date. Restricted shares granted to certain officers and all non-employee directors fully vest after one year.

Our restricted shares are classified as equity awards.

Performance Units

Officers and other key employees are granted performance units under the WEC Energy Group Performance Unit Plan. All grants of performance units are settled in cash and are accounted for as liability awards accordingly. Performance units accrue forfeitable dividend equivalents in the form of additional performance units. The fair value of the performance units reflects our estimate of the final expected value of the awards, which is based on our stock price and performance achievement under the terms of the award. Stock-based compensation costs are generally recorded over the performance period, which is three years.

The ultimate number of units that will be awarded is dependent on our total shareholder return (stock price appreciation plus dividends) as compared to the total shareholder return of a peer group of companies over three years, as well as other performance metrics, as may be determined by the Compensation Committee. Under the terms of awards granted prior to 2023, participants may earn between 0% and 175% of the performance unit award based on our total shareholder return. Pursuant to the plan terms governing these awards, these percentages can be adjusted upwards or downwards by up to 10% based on our performance against additional performance measures, if any, adopted by the Compensation Committee.

The WEC Energy Group Performance Unit Plan was amended and restated, effective January 1, 2023. In accordance with the amended plan, the Compensation Committee selected multiple performance measures that will be weighted to determine the ultimate payout for the awards granted in 2023 and 2024. The ultimate number of units awarded will be based on our total shareholder return compared to the total shareholder return of a peer group of companies over three years (55%), and our performance against the weighted average authorized ROE of all of our utility subsidiaries (45%). In addition, the Compensation

Committee selected the level of our stock price to earnings ratio compared to our peer companies as a performance measure that can increase the payout by up to 25%. In no event can the performance unit payout be greater than 200% of the target award.

See Note 11, Common Equity, for more information on our stock-based compensation plans.

(o) Earnings Per Share—We compute basic earnings per share by dividing our net income attributed to common shareholders by the weighted-average number of common shares outstanding during the period. Diluted earnings per share is computed in a similar manner, but includes the exercise and/or conversion of all potentially dilutive securities, as calculated using the treasury stock method. Such dilutive securities include in-the-money stock options. The calculation of diluted earnings per share for the years ended December 31, 2023, 2022, and 2021 excluded 1,716,286; 653,323; and 769,030 stock options, respectively, that had an anti-dilutive effect.

(p) Leases—We recognize a right of use asset and lease liability for operating and finance leases with a term of greater than one year. As a policy election, we account for each lease component separately from the nonlease components of a contract.

We are currently party to several easement agreements that allow us access to land we do not own for the purpose of constructing and maintaining certain electric power and natural gas equipment. The majority of payments we make related to easements relate to our renewable generating facilities. We have not classified our easements as leases because we view the entire parcel of land specified in our easement agreements to be the identified asset, not just that portion of the parcel that contains our easement. As such, we have concluded that we do not control the use of an identified asset related to our easement agreements, nor do we obtain substantially all of the economic benefits associated with these shared-use assets.

See Note 15, Leases, for more information.

(q) Income Taxes—We follow the liability method in accounting for income taxes. Accounting guidance for income taxes requires the recording of deferred assets and liabilities to recognize the expected future tax consequences of events that have been reflected in our financial statements or tax returns and the adjustment of deferred tax balances to reflect tax rate changes. We are required to assess the likelihood that our deferred tax assets would expire before being realized. If we conclude that certain deferred tax assets are likely to expire before being realized, a valuation allowance would be established against those assets. GAAP requires that, if we conclude in a future period that it is more likely than not that some or all of the deferred tax assets would be realized before expiration, we reverse the related valuation allowance in that period. Any change to the allowance, as a result of a change in judgment about the realization of deferred tax assets, is reported in income tax expense.

ITCs are deferred and amortized over the life of the assets. PTCs are recognized in the period in which such credits are generated. The amount of the credit is based upon power production from our qualifying generation facilities. We file a consolidated federal income tax return. Accordingly, we allocate federal current tax expense, benefits, and credits to our subsidiaries based on their separate tax computations and our ability to monetize all credits on our consolidated federal return.

We recognize interest and penalties accrued, related to unrecognized tax benefits, in income tax expense in our income statements.

The IRA contains a tax credit transferability provision that allows us to sell PTCs produced after December 31, 2022, to third parties. In September 2023, under this transferability provision, we entered into an agreement to sell substantially all of our 2023 PTCs to a third party. We elect to account for tax credits transferred under the scope of ASC 740. We include the discount from the sale of tax credits as a component of income tax expense. We will also include any expected proceeds from the sale of tax credits in the evaluation of the realizability of deferred tax assets related to PTCs. The sale of tax credits is presented in the operating activities section of the statements of cash flows consistent with the presentation of cash taxes paid.

In April 2023, the IRS issued Revenue Procedure 2023-15, which provides a safe harbor method of accounting that taxpayers may use to determine whether expenses to repair, maintain, replace, or improve natural gas transmission and distribution property must be capitalized for tax purposes. We are currently evaluating the impact this guidance may have on our financial statements and related disclosures.

See Note 16, Income Taxes, for more information.

(r) Fair Value Measurements—Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price).

Fair value accounting rules provide a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are defined as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are observable, either directly or indirectly, but are not quoted prices included within Level 1. Level 2 includes those financial instruments that are valued using external inputs within models or other valuation methods.

Level 3 – Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methods that result in management's best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to customers' needs.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. We use a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical measure for valuing certain derivative assets and liabilities. We primarily use a market approach for recurring fair value measurements and attempt to use valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

When possible, we base the valuations of our assets and liabilities on quoted prices for identical assets and liabilities in active markets. These valuations are classified in Level 1. The valuations of certain contracts not classified as Level 1 may be based on quoted market prices received from counterparties and/or observable inputs for similar instruments. Transactions valued using these inputs are classified in Level 2. Certain derivatives, such as FTRs and TCRs, are categorized in Level 3 due to the significance of unobservable or internally-developed inputs. FTRs and TCRs are valued using auction prices from the applicable RTO.

See Note 17, Fair Value Measurements, for more information.

(s) Derivative Instruments—We use derivatives as part of our risk management program to manage the risks associated with the price volatility of interest rates, purchased power, generation, and natural gas costs for the benefit of our customers and shareholders. Our approach is non-speculative and designed to mitigate risk. Regulated hedging programs are approved by our state regulators.

We record derivative instruments on our balance sheets as assets or liabilities measured at fair value unless they qualify for the normal purchases and sales exception, and are so designated. We continually assess our contracts designated as normal and will discontinue the treatment of these contracts as normal if the required criteria are no longer met. Changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met or we receive regulatory treatment for the derivative. For most energy-related physical and financial contracts in our regulated operations that qualify as derivatives, our regulators allow the effects of fair value accounting to be offset to regulatory assets and liabilities.

We classify derivative assets and liabilities as current or long-term on our balance sheets based on the maturities of the underlying contracts. Cash flows from derivative activities are presented in the same category as the item being hedged within operating activities on our statements of cash flows.

Derivative accounting rules provide the option to present certain asset and liability derivative positions net on the balance sheets and to net the related cash collateral against these net derivative positions. We elected not to net these items. On our balance sheets, cash collateral provided to others is reflected in other current assets. See Note 18, Derivative Instruments, for more information.

(t) Guarantees—We follow the guidance of the Guarantees Topic of the FASB ASC, which requires, under certain circumstances, that the guarantor recognize a liability for the fair value of the obligation undertaken in issuing the guarantee at its inception. See Note 19, Guarantees, for more information.

(u) Employee Benefits—The costs of pension and OPEB plans are expensed over the periods during which employees render service. These costs are distributed among our subsidiaries based on current employment status and actuarial calculations, as applicable. Our regulators allow recovery in rates for the utilities' net periodic benefit cost calculated under GAAP. See Note 20, Employee Benefits, for more information.

(v) Customer Deposits and Credit Balances—When utility customers apply for new service, they may be required to provide a deposit for the service. Customer deposits are recorded within other current liabilities on our balance sheets.

Utility customers can elect to be on a budget plan. Under this type of plan, a monthly installment amount is calculated based on estimated annual usage. During the year, the monthly installment amount is reviewed by comparing it to actual usage. If necessary, an adjustment is made to the monthly amount. Annually, the budget plan is reconciled to actual annual usage. Payments in excess of actual customer usage are recorded within other current liabilities on our balance sheets.

(w) Environmental Remediation Costs—We are subject to federal and state environmental laws and regulations that in the future may require us to pay for environmental remediation at sites where we have been, or may be, identified as a potentially responsible party. Loss contingencies may exist for the remediation of hazardous substances at various potential sites, including CCR landfills and manufactured gas plant sites. See Note 9, Asset Retirement Obligations, for more information regarding CCR landfills and Note 24, Commitments and Contingencies, for more information regarding manufactured gas plant sites.

We record environmental remediation liabilities when site assessments indicate remediation is probable, and we can reasonably estimate the loss or a range of losses. The estimate includes both our share of the liability and any additional amounts that will not be paid by other potentially responsible parties or the government. When possible, we estimate costs using site-specific information but also consider historical experience for costs incurred at similar sites. Remediation efforts for a particular site generally extend over a period of several years. During this period, the laws governing the remediation process may change, as well as site conditions, potentially affecting the cost of remediation.

Our utilities have received approval to defer certain environmental remediation costs, as well as estimated future costs, through a regulatory asset. The recovery of deferred costs is subject to the applicable state regulatory commission's approval.

We review our estimated costs of remediation annually for our manufactured gas plant sites and CCR landfills. We adjust the liabilities and related regulatory assets, as appropriate, to reflect the new cost estimates. Any material changes in cost estimates are adjusted throughout the year.

(x) Customer Concentrations of Credit Risk—The geographic concentration of our customers did not contribute significantly to our overall exposure to credit risk. We periodically review customers' credit ratings, financial statements, and historical payment performance and require them to provide collateral or other security as needed. Credit risk exposure at WE, WPS, WG, PGL, and NSG is mitigated by their recovery mechanisms for uncollectible expense discussed in Note 1(d), Operating Revenues. As a result, we did not have any significant concentrations of credit risk at December 31, 2023. In addition, there were no customers that accounted for more than 10% of our revenues for the year ended December 31, 2023.

NOTE 2—ACQUISITIONS

In accordance with Topic 805: Clarifying the Definition of a Business (ASU 2017-01), transactions are evaluated and are accounted for as acquisitions of assets or businesses, and transaction costs are capitalized in asset acquisitions. It was determined that all of the below acquisitions met the criteria of asset acquisitions. The purchase price of certain acquisitions below includes intangibles recorded as long-term liabilities related to PPAs. See Note 10, Goodwill and Intangibles, for more information.

Acquisitions of Electric Generation Facilities in Wisconsin

In June 2023, WE completed the acquisition of 100 MWs of West Riverside's nameplate capacity, in the first of two potential option exercises. West Riverside is a commercially operational dual fueled combined cycle generation facility in Beloit, Wisconsin. Prior to acquisition, WPS received approval to transfer its ownership interest rights to WE. WE's investment was $95.3 million. In addition, WPS filed a request with the PSCW in September 2023 to exercise a second option to acquire an additional 100 MWs of West Riverside's nameplate capacity. As it did with the first option, in October 2023, WPS filed for approval to assign its ownership interest pursuant to this second option to WE. If these approvals are obtained, WE's incremental share of this investment is expected to be approximately $100 million, with the transaction expected to close in 2024.

In April 2023, WPS, along with an unaffiliated utility, completed the acquisition of Red Barn, a commercially operational utility-scale wind-powered electric generating facility. The project is located in Grant County, Wisconsin and WPS owns 82 MWs of this project. WPS's share of the cost of this project was $143.8 million. Red Barn qualifies for PTCs.

In January 2023, WE and WPS completed the acquisition of Whitewater, a commercially operational 236.5 MW dual fueled (natural gas and low sulfur fuel oil) combined cycle electric generation facility in Whitewater, Wisconsin, for $76.0 million.

Acquisition of a Solar Generation Facility in Texas

In February 2023, WECI completed the acquisition of an 80% ownership interest in Samson I, a commercially operational 250 MW solar generating facility in Lamar County, Texas, for $257.3 million, which includes transaction costs and is net of cash acquired. The project has an offtake agreement for all of the energy to be produced by the facility for a period of 15 years from the date of commercial operation. Samson I qualifies for PTCs and is included in the non-utility energy infrastructure segment. In January 2024, WECI acquired an additional 10% ownership interest in Samson I for $28.1 million.

The table below shows the allocation of the purchase price to the assets acquired and liabilities assumed at the date of the original acquisition.

(in millions)		
Accounts receivable	$	0.5
Other current assets		0.7
Net property, plant, and equipment		497.2
Other long-term assets		12.3
Accounts payable		(0.5)
Other current liabilities		(0.8)
Other long-term liabilities		(186.4)
Noncontrolling interest		(65.7)
Total purchase price	$	257.3

Acquisitions of Electric Generation Facilities in Illinois

In February 2023, upon achievement of commercial operation, WECI completed the acquisition of a 90% ownership interest in Sapphire Sky, a 250 MW wind generating facility in McLean County, Illinois, for a total investment of $442.6 million, which includes transaction costs and is net of cash acquired. The project has an offtake agreement for all of the energy to be produced by the facility for a period of 12 years from the date of commercial operation. Sapphire Sky qualifies for PTCs and is included in the non-utility energy infrastructure segment.

The table below shows the allocation of the purchase price to the assets acquired and liabilities assumed at the date of the acquisition.

(in millions)	
Accounts receivable	$ 0.8
Net property, plant, and equipment	642.6
Other long-term assets	1.4
Accounts payable	(1.0)
Other long-term liabilities	(152.0)
Noncontrolling interest	(49.2)
Total purchase price	$ 442.6

In October 2022, WECI signed an agreement to acquire an 80% ownership interest in Maple Flats, a 250 MW solar generating facility under construction in Clay County, Illinois, for approximately $360 million. The project has an offtake agreement for all of the energy to be produced by the facility for a period of 15 years from the date of commercial operation. The transaction is subject to FERC approval and commercial operation is expected to begin during the second half of 2024, at which time the transaction is expected to close. Maple Flats is expected to qualify for PTCs and will be included in the non-utility energy infrastructure segment.

Acquisition of a Wind Generation Facility in Nebraska

In September 2022, WECI completed the acquisition of a 90% ownership interest in Thunderhead, a 300 MW wind generating facility in Antelope and Wheeler counties in Nebraska. The purchase price was $382.0 million, which includes transaction costs and is net of cash acquired. Thunderhead achieved commercial operation in November 2022. The project has an offtake agreement for all of the energy to be produced by the facility for a period of 12 years from the date of commercial operation. Thunderhead qualifies for PTCs and is included in the non-utility energy infrastructure segment.

The table below shows the allocation of the purchase price to the assets acquired and liabilities assumed at the date of the acquisition.

(in millions)	
Accounts receivable	$ 0.2
Other prepayments	0.3
Net property, plant, and equipment	692.3
Other long-term assets	5.1
Other current liabilities	(0.2)
Other long-term liabilities	(273.2)
Noncontrolling interest	(42.5)
Total purchase price	$ 382.0

Acquisition of a Wind Generation Facility in Kansas

In February 2021, WECI completed the acquisition of a 90% ownership interest in Jayhawk, a 190 MW wind generating facility in Bourbon and Crawford counties, Kansas, for $119.9 million, which included transaction costs. This project became commercially operational in December 2021. Subsequent to the acquisition, WECI incurred an additional $161.3 million of capital expenditures as of December 31, 2022 for the project for a total investment of $281.2 million. The project has an offtake agreement for all of the energy to be produced by the facility for a period of 10 years from the date of commercial operation. Jayhawk qualifies for PTCs. WECI is entitled to 99% of the tax benefits related to this facility for the first 10 years of commercial operation, after which it will be entitled to tax benefits equal to its ownership interest. Jayhawk is included in the non-utility energy infrastructure segment.

The table below shows the allocation of the purchase price to the assets acquired and liabilities assumed at the date of the acquisition.

(in millions)	
Net property, plant, and equipment	$ 145.3
Other long-term liabilities	(11.8)
Long-term debt	(7.3)
Noncontrolling interest	(6.3)
Total purchase price	$ 119.9

NOTE 3—DISPOSITIONS

Wisconsin Segment

Sale of Certain Real Estate by Wisconsin Electric Power Company

In June 2023, we sold approximately 192 acres of real estate at WE's former Pleasant Prairie power plant site that was no longer being utilized in its operations, for $23.0 million, which is net of closing costs. As a result of the sale, a pre-tax gain in the amount of $22.2 million was recorded within other operation and maintenance expense on our income statement. The book value of the real estate included in the sale was not material and, therefore, was not presented as held for sale.

Illinois Segment

Sale of Certain Real Estate by The Peoples Gas Light and Coke Company

In May 2022, we sold approximately 11 acres of real estate owned by PGL that was no longer being utilized in its operations, for $55.1 million, which is net of closing costs. The real estate was located in Chicago, Illinois. As a result of the sale, a pre-tax gain in the amount of $54.5 million was recorded within other operation and maintenance expense on our income statement. The book value of the real estate included in the sale was not material and, therefore, was not presented as held for sale.

NOTE 4—OPERATING REVENUES

For more information about our significant accounting policies related to operating revenues, see Note 1(d), Operating Revenues.

Disaggregation of Operating Revenues

The following tables present our operating revenues disaggregated by revenue source. We do not have any revenues associated with our electric transmission segment, which includes investments accounted for using the equity method. We disaggregate revenues into categories that depict how the nature, amount, timing, and uncertainty of revenues and cash flows are affected by economic factors. For our segments, revenues are further disaggregated by electric and natural gas operations and then by customer class. Each customer class within our electric and natural gas operations has different expectations of service, energy and demand requirements, and can be impacted differently by regulatory activities within their jurisdictions.

(in millions)	Wisconsin	Illinois	Other States	Total Utility Operations	Non-Utility Energy Infrastructure	Corporate and Other	Reconciling Eliminations	WEC Ene Grou Consolid
Year ended December 31, 2023								
Electric	$ 4,994.6	$ —	$ —	$ 4,994.6	$ —	$ —	$ —	$ 4,99
Natural gas	1,606.7	1,480.5	493.7	3,580.9	61.9	—	(60.2)	3,58
Total regulated revenues	6,601.3	1,480.5	493.7	8,575.5	61.9	—	(60.2)	8,57
Other non-utility revenues	—	—	19.6	19.6	197.5	0.1	(9.1)	20
Total revenues from contracts with customers	6,601.3	1,480.5	513.3	8,595.1	259.4	0.1	(69.3)	8,78
Other operating revenues	24.6	77.3	5.8	107.7	407.1	—	(407.1) [1]	10
Total operating revenues	$ 6,625.9	$1,557.8	$519.1	$ 8,702.8	$ 666.5	$ 0.1	$ (476.4)	$ 8,89

(in millions)	Wisconsin	Illinois	Other States	Total Utility Operations	Non-Utility Energy Infrastructure	Corporate and Other	Reconciling Eliminations	WEC E Gro Consol
Year ended December 31, 2022								
Electric	$ 4,956.2	$ —	$ —	$ 4,956.2	$ —	$ —	$ —	$ 4
Natural gas	1,980.7	1,883.7	601.8	4,466.2	54.3	—	(51.8)	4
Total regulated revenues	6,936.9	1,883.7	601.8	9,422.4	54.3	—	(51.8)	9
Other non-utility revenues	—	—	18.7	18.7	133.6	—	(9.1)	
Total revenues from contracts with customers	6,936.9	1,883.7	620.5	9,441.1	187.9	—	(60.9)	9
Other operating revenues	23.6	7.2	(2.0)	28.8	402.1	0.5	(402.1) (1)	
Total operating revenues	$ 6,960.5	$1,890.9	$618.5	$ 9,469.9	$ 590.0	$ 0.5	$ (463.0)	$ 9

(in millions)	Wisconsin	Illinois	Other States	Total Utility Operations	Non-Utility Energy Infrastructure	Corporate and Other	Reconciling Eliminations	WEC E Gro Consol
Year Ended December 31, 2021								
Electric	$ 4,516.6	$ —	$ —	$ 4,516.6	$ —	$ —	$ —	$ 4
Natural gas	1,490.3	1,630.3	494.0	3,614.6	46.8	—	(43.8)	3
Total regulated revenues	6,006.9	1,630.3	494.0	8,131.2	46.8	—	(43.8)	8
Other non-utility revenues	—	—	17.8	17.8	92.8	—	(9.1)	
Total revenues from contracts with customers	6,006.9	1,630.3	511.8	8,149.0	139.6	—	(52.9)	8
Other operating revenues	30.1	42.5	7.2	79.8	399.9	0.5	(399.9) [1]	
Total operating revenues	$ 6,037.0	$1,672.8	$519.0	$ 8,228.8	$ 539.5	$ 0.5	$ (452.8)	$ 8

[1] Amounts eliminated represent lease revenues related to certain plants that We Power leases to WE to supply electricity to its customers. Lease payments are billed from We Power to WE and then recovered in WE's rates as authorized by the PSCW and the FERC. WE operates the plants and is authorized by the PSCW and Wisconsin state law to fully recover prudently incurred operating and maintenance costs in electric rates.

Revenues from Contracts with Customers

Electric Utility Operating Revenues

The following table disaggregates electric utility operating revenues into customer class:

(in millions)	Year Ended December 31 2023	2022	2021
Residential	**$ 1,992.3**	$ 1,879.1	$ 1,768.0
Small commercial and industrial	**1,641.1**	1,530.4	1,415.7
Large commercial and industrial	**978.4**	1,042.2	931.9
Other	**30.5**	29.9	29.3
Total retail revenues	**4,642.3**	4,481.6	4,144.9
Wholesale	**120.4**	153.9	157.7
Resale	**195.4**	256.7	161.9
Steam	**25.2**	28.4	28.7
Other utility revenues	**11.3**	35.6	23.4
Total electric utility operating revenues	**$ 4,994.6**	$ 4,956.2	$ 4,516.6

Natural Gas Utility Operating Revenues

The following tables disaggregate natural gas utility operating revenues into customer class:

(in millions)	Wisconsin	Illinois	Other States	Total Natural Gas Utility Operating Revenues
Year ended December 31, 2023				
Residential	**$ 1,012.0**	**$ 966.0**	**$ 324.4**	**$ 2,302.4**
Commercial and industrial	**506.7**	**267.1**	**175.3**	**949.1**
Total retail revenues	**1,518.7**	**1,233.1**	**499.7**	**3,251.5**
Transportation	**93.0**	**231.9**	**32.5**	**357.4**
Other utility revenues [1]	**(5.0)**	**15.5**	**(38.5)**	**(28.0)**
Total natural gas utility operating revenues	**$ 1,606.7**	**$ 1,480.5**	**$ 493.7**	**$ 3,580.9**

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(in millions)	Wisconsin	Illinois	Other States	Total Natural Gas Utility Operating Revenues
Year ended December 31, 2022				
Residential	$ 1,234.0	$ 1,297.4	$ 391.3	$ 2,922.7
Commercial and industrial	672.7	408.8	218.7	1,300.2
Total retail revenues	1,906.7	1,706.2	610.0	4,222.9
Transportation	81.8	259.8	34.5	376.1
Other utility revenues [1] [2]	(7.8)	(82.3)	(42.7)	(132.8)
Total natural gas utility operating revenues	$ 1,980.7	$ 1,883.7	$ 601.8	$ 4,466.2

(in millions)	Wisconsin	Illinois	Other States	Total Natural Gas Utility Operating Revenues
Year Ended December 31, 2021				
Residential	$ 928.9	$ 1,017.9	$ 241.2	$ 2,188.0
Commercial and industrial	472.1	302.1	129.9	904.1
Total retail revenues	1,401.0	1,320.0	371.1	3,092.1
Transportation	80.0	231.2	31.8	343.0
Other utility revenues [1] [3]	9.3	79.1	91.1	179.5
Total natural gas utility operating revenues	$ 1,490.3	$ 1,630.3	$ 494.0	$ 3,614.6

[1] Includes the revenues subject to the purchased gas recovery mechanisms of our utilities, which fluctuate by segment based on actual natural gas costs incurred at our utilities, compared with the recovery of natural gas costs that were anticipated in rates.

[2] During 2022, we continued to recover natural gas costs we under-collected from our customers in 2021 related to the extreme weather experienced in February 2021, as well as higher natural gas costs incurred at the majority of our segments during 2022. As these amounts are billed to customers, they are reflected in retail revenues with an offsetting decrease in other utility revenues.

[3] During 2021, in addition to costs related to the extreme weather event experienced in February 2021, we incurred higher natural gas costs as a result of an increase in the price of natural gas.

See Note 26, Regulatory Environment, for more information.

Other Non-Utility Operating Revenues

Other non-utility operating revenues consist primarily of the following:

(in millions)	Year Ended December 31 2023	2022	2021
Renewable generation revenues	**$ 164.9**	$ 101.0	$ 60.3
We Power revenues	**23.5**	23.4	23.3
Appliance service revenues	**19.6**	18.7	17.8
Other	**0.1**	0.1	0.1
Total other non-utility operating revenues	**$ 208.1**	$ 143.2	$ 101.5

Other Operating Revenues

Other operating revenues consist primarily of the following:

(in millions)	Year Ended December 31 2023	2022	2021
Late payment charges	**$ 56.5**	$ 55.6	$ 54.9
Alternative revenues [(1)]	**47.0**	(30.3)	21.2
Other	**4.2**	4.0	4.2
Total other operating revenues	**$ 107.7**	$ 29.3	$ 80.3

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(1) Negative amounts can result from alternative revenues being reversed to revenues from contracts with customers as the customer is billed for these alternative revenues. Negative amounts can also result from revenues to be refunded to customers subject to decoupling mechanisms, wholesale true-ups, and conservation improvement rider true-ups.

NOTE 5—CREDIT LOSSES

We have included tables below that show our gross third-party receivable balances and the related allowance for credit losses at December 31, 2023 and 2022, by reportable segment.

(in millions)	Wisconsin	Illinois	Other States	Total Utility Operations	Non-Utility Energy Infrastructure	Corporate and Other	WEC Energy Group Consolidated
December 31, 2023							
Accounts receivable and unbilled revenues	**$1,078.0**	**$481.5**	**$94.9**	**$1,654.4**	**$ 33.9**	**$ 8.4**	**$ 1,696.7**
Allowance for credit losses	**77.4**	**109.7**	**6.4**	**193.5**	**—**	**—**	**193.5**
Accounts receivable and unbilled revenues, net (1)	**$1,000.6**	**$371.8**	**$88.5**	**$1,460.9**	**$ 33.9**	**$ 8.4**	**$ 1,503.2**
Total accounts receivable, net – past due greater than 90 days (1)	**$ 51.7**	**$ 45.0**	**$ 2.1**	**$ 98.8**	**$ —**	**$ —**	**$ 98.8**
Past due greater than 90 days – collection risk mitigated by regulatory mechanisms (1)	**93.6 %**	**100.0 %**	**— %**	**94.5 %**	**— %**	**— %**	**94.5 %**

(in millions)	Wisconsin	Illinois	Other States	Total Utility Operations	Non-Utility Energy Infrastructure	Corporate and Other	WEC Energy Group Consolidated
December 31, 2022							
Accounts receivable and unbilled revenues	$1,199.4	$624.2	$164.4	$ 1,988.0	$ 25.4	$ 4.3	$ 2,017.7
Allowance for credit losses	82.0	111.0	6.3	199.3	—	—	199.3
Accounts receivable and unbilled revenues, net [1]	$1,117.4	$513.2	$158.1	$ 1,788.7	$ 25.4	$ 4.3	$ 1,818.4
Total accounts receivable, net – past due greater than 90 days [1]	$ 51.9	$ 52.9	$ 1.9	$ 106.7	$ —	$ —	$ 106.7
Past due greater than 90 days – collection risk mitigated by regulatory mechanisms [1]	97.0 %	100.0 %	— %	96.8 %	— %	— %	96.8 %

[1] Our exposure to credit losses for certain regulated utility customers is mitigated by regulatory mechanisms we have in place. Specifically, rates related to all of the customers in our Illinois segment, as well as the residential rates of WE, WPS, and WG in our Wisconsin segment, include riders or other mechanisms for cost recovery or refund of uncollectible expense based on the difference between the actual provision for credit losses and the amounts recovered in rates. As a result, at December 31, 2023, $914.6 million, or 60.8%, of our net accounts receivable and unbilled revenues balance had regulatory protections in place to mitigate the exposure to credit losses.

A rollforward of the allowance for credit losses by reportable segment for the years ended December 31, 2023, 2022, and 2021, is included below:

(in millions)	Wisconsin	Illinois	Other States	WEC Energy Group Consolidated
Balance at January 1, 2023	$ 82.0	$ 111.0	$ 6.3	$ 199.3
Provision for credit losses	40.9	26.3	4.8	72.0
Provision for credit losses deferred for future recovery or refund	52.5	35.8	—	88.3
Write-offs charged against the allowance	(131.6)	(85.4)	(6.6)	(223.6)
Recoveries of amounts previously written off	33.6	22.0	1.9	57.5
Balance at December 31, 2023	$ 77.4	$ 109.7	$ 6.4	$ 193.5

On a consolidated basis, there was a $5.8 million decrease in the allowance for credit losses during the year ended December 31, 2023, primarily related to lower customer energy costs (driven by the warmer weather during the fourth quarter of 2023 when compared to the same quarter in 2022 and lower natural gas prices), which contributed to a reduction in past due accounts receivable balances and a related decrease in the allowance for credit losses. Customer write-offs also contributed to the decrease in the allowance for credit losses. After a customer is disconnected for a period of time without payment on their account, we will write off that customer balance.

(in millions)	Wisconsin	Illinois	Other States	WEC Energy Group Consolidated
Balance at January 1, 2022	$ 84.0	$ 105.5	$ 8.8	$ 198.3
Provision for credit losses	50.5	33.0	2.6	86.1
Provision for credit losses deferred for future recovery or refund	29.7	33.2	—	62.9
Write-offs charged against the allowance	(117.0)	(82.6)	(6.4)	(206.0)
Recoveries of amounts previously written off	34.8	21.9	1.3	58.0
Balance at December 31, 2022	$ 82.0	$ 111.0	$ 6.3	$ 199.3

On a consolidated basis, there was a $1.0 million increase in the allowance for credit losses during the year ended December 31, 2022. We believe that the high energy costs that customers were seeing, which were driven by high natural gas prices, contributed to higher past due accounts receivable balances and a related increase in the allowance for credit losses. The increase was substantially offset by customer write-offs related to collection practices returning to pre-pandemic levels, including the restoration of our ability to disconnect customers.

(in millions)	Wisconsin	Illinois	Other States	WEC Energy Group Consolidated
Balance at January 1, 2021	$ 102.1	$ 111.6	$ 6.4	$ 220.1
Provision for credit losses	46.4	25.6	3.7	75.7
Provision for credit losses deferred for future recovery or refund	(16.6)	3.5	—	(13.1)
Write-offs charged against the allowance	(74.8)	(52.5)	(2.5)	(129.8)
Recoveries of amounts previously written off	26.9	17.3	1.2	45.4
Balance at December 31, 2021	$ 84.0	$ 105.5	$ 8.8	$ 198.3

The allowance for credit losses decreased during the year ended December 31, 2021, primarily related to normal collection practices resuming in April 2021 for our Wisconsin utilities and in June 2021 for our Illinois utilities. Across all of our reportable segments, higher year-over-year natural gas prices drove an increase in gross accounts receivable balances, partially offsetting the decrease in the allowance for credit losses attributed to collection efforts.

NOTE 6—REGULATORY ASSETS AND LIABILITIES

The following regulatory assets were reflected on our balance sheets as of December 31:

(in millions)	2023	2022	See Note
Regulatory assets [1] [2]			
Pension and OPEB costs [3]	**$ 731.7**	$ 714.3	20, 26
Plant retirement related items	**646.2**	688.6	
Environmental remediation costs [4]	**596.8**	610.7	24
Income tax related items	**449.9**	461.9	16
AROs	**162.0**	169.7	1(l), 9
Derivatives	**130.3**	133.8	1(s)
Uncollectible expense	**127.7**	69.3	5
SSR [5]	**113.2**	123.5	
Securitization	**85.9**	92.4	23
Bluewater [6]	**45.3**	20.9	
Energy efficiency programs [7]	**33.9**	33.9	
Energy costs recoverable through rate adjustments	**3.2**	26.9	1(d)
MERC extraordinary natural gas costs [8]	**0.8**	35.1	26
Other, net	**147.8**	125.9	
Total regulatory assets	**$ 3,274.7**	$ 3,306.9	
Balance sheet presentation			
Other current assets	**$ 24.9**	$ 42.3	
Regulatory assets	**3,249.8**	3,264.6	
Total regulatory assets	**$ 3,274.7**	$ 3,306.9	

(1) Based on prior and current rate treatment, we believe it is probable that our utilities will continue to recover from customers the regulatory assets in this table. In accordance with GAAP, our regulatory assets do not include the allowance for ROE that is capitalized for regulatory purposes. This allowance was $26.7 million and $27.3 million at December 31, 2023 and 2022, respectively.

(2) As of December 31, 2023, we had $254.6 million of regulatory assets not earning a return, $5.4 million of regulatory assets earning a return based on short-term interest rates, $129.7 million of regulatory assets earning a return based on long-term interest rates, and $2.5 million of regulatory assets earning a return based on the applicable utility's ROE. The regulatory assets not earning a return primarily relate to certain environmental remediation costs, uncollectible expense, our invested capital tax rider, decoupling mechanisms, unamortized loss on reacquired debt, and rate case costs. The other regulatory assets in the table either earn a return at the applicable utility's weighted average cost of capital or the cash has not yet been expended, in which case the regulatory assets are offset by liabilities.

(3) Primarily represents the unrecognized future pension and OPEB costs related to our defined benefit pension and OPEB plans. We are authorized recovery of these regulatory assets over the average remaining service life of each plan.

(4) As of December 31, 2023, we had made cash expenditures of $133.1 million related to these environmental remediation costs. The remaining $463.7 million represents our estimated future cash expenditures.

(5) This regulatory asset relates to WE's 2014 announcement to retire the PIPP. Despite WE's intent to retire the PIPP, MISO designated the PIPP as a SSR, which meant the PIPP's operation was necessary for reliability, and the plant could not be shut down until new generation or transmission facilities were built. In December 2014, the PSCW authorized escrow accounting for WE's SSR revenues because of the fluctuations in the actual revenues WE received under the PIPP SSR agreements. The rate order WE received from the PSCW in December 2019 authorized recovery of this SSR regulatory asset over a 15-year period that began on January 1, 2020.

(6) Primarily relates to costs associated with the long-term service agreements our Wisconsin utilities have with Bluewater for natural gas storage services. The PSCW has approved escrow accounting for these costs. As a result, our Wisconsin utilities defer as a regulatory asset or liability the difference between actual storage costs and those included in rates until recovery or refund is authorized in a future rate proceeding.

(7) Represents amounts recoverable from customers related to programs at the utilities designed to meet energy efficiency standards.

(8) Represents the extraordinary natural gas costs MERC incurred during February 2021 that were substantially recovered over 27 months, beginning in September 2021. See Note 26, Regulatory Environment, for more information on our recovery efforts associated with these costs.

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The following regulatory liabilities were reflected on our balance sheets as of December 31:

(in millions)	2023	2022	See Note
Regulatory liabilities			
Income tax related items	**$ 1,901.8**	$ 1,956.6	16
Removal costs [1]	**1,329.9**	1,260.9	
Pension and OPEB benefits [2]	**299.2**	340.5	20, 26
Energy costs refundable through rate adjustments	**72.4**	53.4	1(d)
Electric transmission costs [3]	**30.3**	0.4	
Uncollectible expense	**21.2**	24.0	5
Derivatives	**19.2**	76.7	1(s)
Energy efficiency programs [4]	**17.2**	10.4	
Decoupling	**—**	20.2	1(d)
Other, net	**54.0**	48.8	
Total regulatory liabilities	**$ 3,745.2**	$ 3,791.9	
Balance sheet presentation			
Other current liabilities	**$ 47.5**	$ 56.4	
Regulatory liabilities	**3,697.7**	3,735.5	
Total regulatory liabilities	**$ 3,745.2**	$ 3,791.9	

(1) Represents amounts collected from customers to cover the future cost of property, plant, and equipment removals that are not legally required. Legal obligations related to the removal of property, plant, and equipment are recorded as AROs. See Note 9, Asset Retirement Obligations, for more information on our legal obligations.

(2) Primarily represents the unrecognized future pension and OPEB benefits related to our defined benefit pension and OPEB plans. We will amortize these regulatory liabilities into net periodic benefit cost over the average remaining service life of each plan.

(3) In accordance with the PSCW's approval of escrow accounting for ATC and MISO network transmission expenses for our Wisconsin electric utilities, WE and WPS defer as a regulatory asset or liability the difference between actual transmission costs and those included in rates until recovery or refund is authorized in a future rate proceeding.

(4) Represents amounts refundable to customers related to programs at the utilities designed to meet energy efficiency standards.

Pleasant Prairie Power Plant

The Pleasant Prairie power plant was retired on April 10, 2018. The net book value of this plant was $542.4 million at December 31, 2023, representing book value less cost of removal and accumulated depreciation. In addition, previously deferred unprotected tax benefits from the Tax Legislation related to the unrecovered balance of this plant were $16.4 million as of December 31, 2023. The net amount of $526.0 million was classified as a regulatory asset on our balance sheet at December 31, 2023 due to the retirement of the plant. This regulatory asset does not include certain other previously recorded deferred tax liabilities of $147.8 million related to the retired Pleasant Prairie power plant. Pursuant to its rate order issued by the PSCW in December 2019, WE will continue to amortize this regulatory asset on a straight-line basis through 2039, using the composite depreciation rates approved by the PSCW before this plant was retired. The amortization is included in depreciation and amortization in the income statement. WE also has FERC approval to continue to collect the net book value of the Pleasant Prairie power plant using the approved composite depreciation rates, in addition to a return on the remaining net book value.

WE received approval from the PSCW in December 2019 to collect a full return of the net book value of the Pleasant Prairie power plant and a return on all but $100 million of the net book value. During May 2021, WE securitized the remaining $100 million of the Pleasant Prairie power plant's book value, the carrying costs accrued on the $100 million during the securitization process, and the related financing fees, in accordance with a written order issued by the PSCW in November 2020. See Note 23, Variable Interest Entities, for more information on this securitization.

Presque Isle Power Plant

Pursuant to MISO's April 2018 approval of the retirement of the PIPP, these units were retired on March 31, 2019. The net book value of the PIPP was $152.9 million at December 31, 2023, representing book value less cost of removal and accumulated depreciation. In addition, previously deferred unprotected tax benefits from the Tax Legislation related to the unrecovered balance of these units were $4.8 million as of December 31, 2023. The net amount of $148.1 million was classified as a regulatory asset on our balance sheet at December 31, 2023 as a result of the retirement of the plant. This regulatory asset does not include certain other previously recorded deferred tax liabilities of $41.5 million related to the retired PIPP. After the retirement of the PIPP, a portion of the regulatory asset and related cost of removal reserve was transferred to UMERC for recovery from its retail customers. Effective with its rate order issued by the PSCW in December 2019, WE received approval to collect a return of and on its share of the net book value of the PIPP and, as a result, will continue to amortize the regulatory assets on a straight-line basis through 2037, using the composite depreciation rates approved by the PSCW before the units were retired. UMERC will also continue to amortize the regulatory assets on a straight-line basis using the composite depreciation rates approved by the PSCW before the units were retired. This amortization is included in depreciation and amortization in the income statement. UMERC will address the accounting and regulatory treatment related to the retirement of the PIPP with the MPSC in conjunction with a future rate case. WE also has FERC approval to continue to collect the net book value of the PIPP using the approved composite depreciation rates, in addition to a return on the net book value.

Pulliam Power Plant

In connection with a MISO ruling, WPS retired Pulliam Units 7 and 8 on October 21, 2018. The net book value of the Pulliam units was $33.0 million at December 31, 2023, representing book value less cost of removal and accumulated depreciation. This amount was classified as a regulatory asset on our balance sheet at December 31, 2023 as a result of the retirement of the plant. Effective with its rate order issued by the PSCW in December 2019, WPS received approval to collect a return of and on the entire net book value of the Pulliam units and, as a result, will continue to amortize this regulatory asset on a straight-line basis through 2031, using the composite depreciation rates approved by the PSCW before these generating units were retired. The amortization is included in depreciation and amortization in the income statement. WPS also has FERC approval to continue to collect the net book value of the Pulliam power plant using the approved composite depreciation rates, in addition to a return on the remaining net book value.

Edgewater Unit 4

The Edgewater 4 generating unit was retired on September 28, 2018. The net book value of the generating unit was $2.1 million at December 31, 2023, representing book value less cost of removal and accumulated depreciation. This amount was classified as a regulatory asset on our balance sheet at December 31, 2023 as a result of the retirement of the plant. Effective with its rate order issued by the PSCW in December 2019, WPS received approval to collect a return of and on the entire net book value of the Edgewater 4 generating unit and, as a result, will continue to amortize this regulatory asset on a straight-line basis through 2026, using the composite depreciation rates approved by the PSCW before this generating unit was retired. The amortization is included in depreciation and amortization in the income statement. WPS also has FERC approval to continue to collect the net book value of the Edgewater 4 generating unit using the approved composite depreciation rates, in addition to a return on the remaining net book value.

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NOTE 7—PROPERTY, PLANT, AND EQUIPMENT

Property, plant, and equipment consisted of the following at December 31:

(in millions)	2023	2022
Electric – generation	$ 6,190.4	$ 5,480.5
Electric – distribution	8,688.0	8,233.3
Natural gas – distribution, storage, and transmission	14,851.3	14,203.3
Property, plant, and equipment to be retired, net	1,043.5	1,085.6
Other	2,350.0	2,302.7
Less: Accumulated depreciation	8,907.9	8,416.2
Net	24,215.3	22,889.2
CWIP	1,118.3	972.1
Net utility and non-utility property, plant, and equipment	25,333.6	23,861.3
We Power generation	3,295.9	3,237.1
Renewable generation	3,667.7	2,537.1
Natural gas storage	291.6	292.2
Net non-utility energy infrastructure	7,255.2	6,066.4
Corporate services	169.8	163.0
Other	14.3	23.8
Less: Accumulated depreciation	1,227.5	1,082.3
Net	6,211.8	5,170.9
CWIP	36.1	81.6
Net other property, plant, and equipment	6,247.9	5,252.5
Total property, plant, and equipment	$ 31,581.5	$ 29,113.8

Severance Liability for Plant Retirements

We have severance liabilities related to past and future plant retirements recorded in other current and other long-term liabilities on our balance sheets. Activity related to these severance liabilities for the years ended December 31 was as follows:

(in millions)	2023	2022	2021
Severance liability at January 1	$ 16.2	$ 4.9	$ 0.7
Severance expense	1.6	11.3	4.6
Severance payments	—	—	(0.4)
Total severance liability at December 31	$ 17.8	$ 16.2	$ 4.9

Wisconsin Segment Plant to be Retired

Oak Creek Power Plant Units 5-8

As a result of a PSCW approval in December 2022 for the acquisition and construction of Darien, the retirement of OCPP Units 5-8 became probable. In early 2023, we received additional approvals for electric generation facilities, including Koshkonong and 100 MWs of West Riverside. See Note 2, Acquisitions, for more information on the West Riverside acquisition, which was completed in June 2023. OCPP Units 5 and 6 are expected to be retired by May 2024, while OCPP Units 7 and 8 are expected to be retired by late 2025. The total net book value of WE's ownership share of OCPP Units 5-8 was $783.7 million at December 31, 2023, which does not include deferred taxes. This amount was classified as plant to be retired within property, plant, and equipment on our balance sheet. These units are included in rate base, and WE continues to depreciate them on a straight-line basis using the composite depreciation rates approved by the PSCW.

Columbia Units 1 and 2

As a result of a MISO ruling received in June 2021, retirement of the jointly-owned Columbia Units 1 and 2 became probable. Columbia Units 1 and 2 are expected to be retired by June 2026. The total net book value of WPS's ownership share of Columbia

Units 1 and 2 was $259.8 million at December 31, 2023, which does not include deferred taxes. This amount was classified as plant to be retired within property, plant, and equipment on our balance sheet. These units are included in rate base, and WPS continues to depreciate them on a straight-line basis using the composite depreciation rates approved by the PSCW.

The Peoples Gas Light and Coke Company and North Shore Gas Company Impairment

In November 2023, the ICC issued written rate orders that disallowed $177.2 million of previously incurred capital costs related to the construction and improvement of PGL's service centers and $1.7 million of capital costs related to NSG's construction of a gas infrastructure project. As a result of these disallowances, we recorded a $178.9 million non-cash impairment of our property, plant, and equipment in 2023. We anticipate appealing the ICC's disallowance of these capital costs to the Illinois circuit court. See Note 26, Regulatory Environment, for more information.

Samson I Solar Energy Center LLC – Storm Damage

During wind storms in March and June 2023, certain sections of our Samson I solar facility incurred damage. As of December 31, 2023, we recognized an impairment of $2.3 million related to storm damage, which was offset by a $2.3 million receivable for future insurance recoveries. Although we may experience differences between periods in the timing of cash flows, we do not currently expect a significant impact to our long-term cash flows from this event.

Public Service Building and Steam Tunnel Assets

During a significant rain event in May 2020, an underground steam tunnel in downtown Milwaukee flooded and steam vented into WE's PSB. The damage to the building and adjacent steam tunnel assets from the flooding and steam was extensive and required significant repairs and restorations. As of December 31, 2023, WE had incurred $95.3 million of costs related to these repairs and restorations. In June 2021, we received approval from the PSCW to restore the PSB and adjacent steam tunnel assets and to defer the project costs, net of insurance proceeds, as a component of rate base. As a result, we do not currently expect a significant impact to our future results of operations.

NOTE 8—JOINTLY OWNED UTILITY FACILITIES

Our electric utilities hold joint ownership interests in certain electric generating facilities. We are entitled to our share of generating capability and output of each facility equal to our respective ownership interest. We have supplied our own financing for all jointly owned projects. We pay our ownership share of additional construction costs, fuel inventory purchases, and operating expenses, unless specific agreements have been executed to limit our maximum exposure to additional costs. We record our proportionate share of significant jointly owned electric generating facilities as property, plant, and equipment on the balance sheets. In addition, our proportionate share of direct expenses for the joint operation of these plants is recorded within operating expenses in the income statements.

Information related to jointly owned utility facilities at December 31, 2023 was as follows:

Company	Jointly-Owned Utility Facilities	Ownership	Share of Capacity (MW)	In-Service / Acquisition Date	Operating Owner	Property, Plant, and Equipment	Accumulated Depreciation	CWIP
(in millions, except for percentages and MW)								
We Power [1]	ER 1 & ER 2 [2]	**83.34 %**	**1,082.1**	**2010 & 2011**	**WE**	**$ 2,487.4**	**$ (520.0)**	**$ 6.2**
WPS	Weston Unit 4 [2]	**70.0 %**	**384.8**	**2008**	**WPS**	**613.3**	**(227.3)**	**0.5**
WPS	Columbia Energy Center Units 1 and 2 [2] [5]	**27.5 %**	**312.3**	**1975 & 1978**	**WPL**	**433.1**	**(173.8)**	**3.5**
WPS	Forward Wind [3]	**44.6 %**	**61.5**	**2008**	**WPS**	**119.3**	**(56.8)**	**—**
WPS	Two Creeks [4]	**66.7 %**	**100.0**	**2020**	**WPS**	**136.9**	**(14.1)**	**—**
WPS	Badger Hollow I [4]	**66.7 %**	**100.0**	**2021**	**WPS**	**146.2**	**(9.7)**	**0.1**
WPS	Red Barn [3]	**90.0 %**	**82.4**	**2023**	**WPS**	**150.0**	**(3.2)**	**—**
WE	West Riverside [2] [6]	**13.8 %**	**84.9**	**2023**	**WE**	**108.7**	**(11.3)**	**0.9**
WE	Badger Hollow II [4]	**66.7 %**	**100.0**	**2023**	**WE**	**170.1**	**(0.3)**	**0.1**

[1] We Power leases its ownership interest in ER 1 and ER 2 to WE.

(2) Capacity is based on rated capacity, which is the net power output under average operating conditions with equipment in an average state of repair as of a given month in a given year. Values are primarily based on the net dependable expected capacity ratings for summer 2024 established by tests and may change slightly from year to year. The summer period is the most relevant for capacity planning purposes. This is a result of continually reaching demand peaks in the summer months, primarily due to air conditioning demand.

(3) Capacity for wind generating facilities is based on nameplate capacity, which is the amount of energy a turbine should produce at optimal wind speeds.

(4) Capacity for solar generating facilities is based on nameplate capacity, which is the maximum output that a generator should produce at continuous full power.

(5) These units are expected to be retired by June 2026. See Note 7, Property, Plant, and Equipment, for more information.

(6 WE acquired its ownership interest in June 2023. In September 2023, WPS filed a request with the PSCW to exercise a second option to acquire an additional 100 MWs of West Riverside's nameplate capacity. WPS subsequently filed for approval to assign its ownership interest pursuant to this second option to WE. See Note 2, Acquisitions, for more information.

WE and WPS, along with an unaffiliated utility, received PSCW approval to construct Koshkonong, a utility-scale solar-powered electric generating facility. The project will be located in Dane County, Wisconsin and once fully constructed, WE and WPS will collectively own 90%, or 270 MWs of solar generation of this project. Commercial operation of the solar facility is targeted for 2026. Our CWIP balance for Koshkonong was not significant as of December 31, 2023.

WE and WPS, along with an unaffiliated utility, received PSCW approval to construct Paris, a utility-scale solar-powered electric generating facility with a battery energy storage system. The project will be located in Kenosha County, Wisconsin and once fully constructed, WE and WPS will collectively own 90%, or 180 MWs of solar generation and 99 MWs of battery storage of this project. Commercial operation of the solar facility is targeted for 2024 and construction of the battery storage is expected to be completed in 2025. Our CWIP balance for Paris was $334.3 million as of December 31, 2023.

WE and WPS, along with an unaffiliated utility, received PSCW approval to construct Darien, a utility-scale solar-powered electric generating facility. The project will be located in Rock and Walworth counties, Wisconsin and once constructed, WE and WPS will collectively own 90%, or 225 MWs of solar generation of this project. Commercial operation of the solar facility is targeted for 2024. Our CWIP balance for Darien was $220.4 million as of December 31, 2023.

NOTE 9—ASSET RETIREMENT OBLIGATIONS

Our utilities have recorded AROs primarily for the removal of natural gas distribution mains and service pipes (including asbestos and PCBs); asbestos abatement at certain generation and substation facilities, office buildings, and service centers; the removal and dismantlement of a biomass generation facility; the dismantling of wind and solar generation projects; the disposal of PCB-contaminated transformers; the closure of CCR landfills at certain generation facilities; and the removal of above ground and underground storage tanks. Regulatory assets and liabilities are established by our utilities to record the differences between ongoing expense recognition under the ARO accounting rules and the ratemaking practices for retirement costs authorized by the applicable regulators.

WECI has also recorded AROs for the dismantling of our non-utility renewable generation projects.

The following table shows changes to our AROs during the years ended December 31:

(in millions)	**2023**	2022	2021
Balance as of January 1	**$ 479.3**	$ 462.0	$ 513.5
Accretion	**17.2**	16.1	21.2
Additions	**24.0** [1]	12.8 [3]	31.0 [4]
Revisions to estimated cash flows	**(133.5)** [2]	2.2	(84.9) [5]
Liabilities settled	**(12.8)**	(13.8)	(18.8)
Balance as of December 31	**$ 374.2**	$ 479.3	$ 462.0

[1] AROs increased primarily as a result of AROs being recorded for the legal requirement to dismantle, at retirement, the Red Barn wind-powered generation project, the Badger Hollow II solar generation project, and the Sapphire Sky and Samson I non-utility renewable generation projects.

(2) AROs decreased primarily due to revisions made to estimated cash flows for changes in removal cost estimates and settlements dates for mains and services at PGL and NSG.

(3) AROs increased primarily as a result of an ARO being recorded for the legal requirement to dismantle, at retirement, the Thunderhead non-utility wind generation project.

(4) AROs increased as a result of AROs being recorded for the legal requirement to dismantle, at retirement, the Badger Hollow I solar generation project and the Tatanka Ridge and Jayhawk non-utility renewable generation projects.

(5) AROs decreased due to revisions made to estimated cash flows primarily for changes in the cost to retire natural gas distribution lines at PGL and NSG. Partially offsetting this decrease were revisions made to removal estimates for wind generation projects at WE and WPS and for fly ash landfills and ash ponds at WPS.

NOTE 10—GOODWILL AND INTANGIBLES

Goodwill

Goodwill represents the excess of the cost of an acquisition over the fair value of the identifiable net assets acquired. The table below shows our goodwill balances by segment at December 31, 2023. We had no changes to the carrying amount of goodwill during the years ended December 31, 2023 and 2022.

(in millions)	Wisconsin	Illinois	Other States	Non-Utility Energy Infrastructure	Total
Goodwill balance (1)	$ 2,104.3	$ 758.7	$ 183.2	$ 6.6	$ 3,052.8

(1) We had no accumulated impairment losses related to our goodwill as of December 31, 2023.

During the third quarter of 2023, annual impairment tests were completed at all of our reporting units that carried a goodwill balance as of July 1, 2023. No impairments resulted from these tests.

Intangible Assets

At December 31, 2023 and 2022, we had $29.3 million and $24.9 million, respectively, of indefinite-lived intangible assets, largely consisting of spectrum frequencies. During 2023, we purchased additional spectrum frequencies for $4.4 million. The spectrum frequencies enable the utilities to transmit data and voice communications over a wavelength dedicated to us throughout our service territories. We also have $5.2 million of other indefinite-lived intangible assets, consisting of a MGU trade name from a previous acquisition. These indefinite-lived intangible assets are included in other long-term assets on our balance sheets.

Intangible Liabilities

The intangible liabilities below were all obtained through acquisitions by WECI.

(in millions)	December 31, 2023 Gross Carrying Amount	December 31, 2023 Accumulated Amortization	December 31, 2023 Net Carrying Amount	December 31, 2022 Gross Carrying Amount	December 31, 2022 Accumulated Amortization	December 31, 2022 Net Carrying Amount
PPAs [(1)]	**$ 653.9**	**$ (66.6)**	**$ 587.3**	$ 343.9	$ (16.9)	$ 327.0
Proxy revenue swap [(2)]	**7.2**	**(3.5)**	**3.7**	7.2	(2.8)	4.4
Interconnection agreements [(3)]	**4.7**	**(0.9)**	**3.8**	4.7	(0.7)	4.0
Total intangible liabilities	**$ 665.8**	**$ (71.0)**	**$ 594.8**	$ 355.8	$ (20.4)	$ 335.4

(1) Represents PPAs related to the acquisition of Blooming Grove, Tatanka Ridge, Jayhawk, Thunderhead, Samson I, and Sapphire Sky expiring between 2030 and 2037. The weighted-average remaining useful life of the PPAs is 11 years. See Note 2, Acquisitions, for more information on the acquisitions of Samson I and Sapphire Sky in 2023.

(2) Represents an agreement with a counterparty to swap the market revenue of Upstream's wind generation for fixed quarterly payments over 10 years, which expires in 2029. The remaining useful life of the proxy revenue swap is five years.

(3) Represents interconnection agreements related to the acquisitions of Tatanka Ridge and Bishop Hill III, expiring in 2040 and 2041, respectively. These agreements relate to payments for connecting our facilities to the infrastructure of another utility to facilitate the movement of power onto the electric grid. The weighted-average remaining useful life of the interconnection agreements is 17 years.

Amortization related to these intangible liabilities for the years ended December 31, 2023, 2022, and 2021 was $50.6 million, $11.3 million, and $7.5 million, respectively. Amortization for the next five years is estimated to be:

	For the Years Ending December 31				
(in millions)	**2024**	**2025**	**2026**	**2027**	**2028**
Amortization to be recorded as an increase to operating revenues	$ 53.4	$ 53.4	$ 53.4	$ 53.4	$ 53.4
Amortization to be recorded as a decrease to other operation and maintenance	0.2	0.2	0.2	0.2	0.2

NOTE 11—COMMON EQUITY

Stock-Based Compensation

The following table summarizes our pre-tax stock-based compensation expense and the related tax benefit recognized in income for the years ended December 31:

(in millions)	**2023**	**2022**	**2021**
Stock options	**$ 5.3**	$ 6.5	$ 6.5
Restricted stock	**6.6**	7.0	6.1
Performance units	**(2.2)** (1)	21.3	3.1
Stock-based compensation expense	**$ 9.7**	$ 34.8	$ 15.7
Related tax benefit	**$ 2.7**	$ 9.6	$ 4.3

(1) The reduction in expense was due to a decrease in the fair value of the outstanding performance units.

Stock-based compensation costs capitalized during 2023, 2022, and 2021 were not significant.

Stock Options

The following is a summary of our stock option activity during 2023:

Stock Options	Number of Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (in years)	Aggregate Intrinsic Value (in millions)
Outstanding as of January 1, 2023	2,909,939	$ 77.03		
Granted	257,780	93.69		
Exercised	(129,743)	48.44		
Forfeited	(17,053)	93.34		
Expired	(5,172)	91.49		
Outstanding as of December 31, 2023	3,015,751	79.57	5.7	$ 28.7
Exercisable as of December 31, 2023	2,052,968	73.03	4.6	$ 28.7

The aggregate intrinsic value of outstanding and exercisable options in the above table represents the total pre-tax intrinsic value that would have been received by the option holders had they exercised all of their options on December 31, 2023. This is calculated as the difference between our closing stock price on December 31, 2023, and the option exercise price, multiplied by the number of in-the-money stock options. The intrinsic value of options exercised during the years ended December 31, 2023, 2022, and 2021 was $5.2 million, $29.2 million, and $12.9 million, respectively. The actual tax benefit from option exercises for the same years was approximately $1.4 million, $8.0 million, and $3.5 million, respectively.

As of December 31, 2023, approximately $1.7 million of unrecognized compensation cost related to unvested and outstanding stock options was expected to be recognized over the next 1.5 years on a weighted-average basis.

During the first quarter of 2024, the Compensation Committee awarded 283,869 non-qualified stock options with a weighted-average exercise price of $85.05 and a weighted-average grant date fair value of $16.20 per option to certain of our officers and other key employees under its normal schedule of awarding long-term incentive compensation.

Restricted Shares

The following restricted stock activity occurred during 2023:

Restricted Shares	Number of Shares	Weighted-Average Grant Date Fair Value
Outstanding and unvested as of January 1, 2023	**89,885**	**$ 94.73**
Granted	**75,453**	**93.69**
Released	**(61,782)**	**94.75**
Forfeited	**(3,158)**	**94.08**
Outstanding and unvested as of December 31, 2023	**100,398**	**93.95**

The intrinsic value of restricted stock released was $5.8 million, $7.5 million, and $6.5 million for the years ended December 31, 2023, 2022, and 2021, respectively. The actual tax benefit from released restricted shares for the same years was $1.6 million, $2.1 million, and $1.8 million, respectively.

As of December 31, 2023, approximately $2.9 million of unrecognized compensation cost related to unvested and outstanding restricted stock was expected to be recognized over the next 1.7 years on a weighted-average basis.

During the first quarter of 2024, the Compensation Committee awarded 105,778 restricted shares to certain of our directors, officers, and other key employees under its normal schedule of awarding long-term incentive compensation. The grant date fair value of these awards was $85.05 per share.

Performance Units

During 2023, 2022, and 2021, the Compensation Committee awarded 157,035; 171,492; and 152,382 performance units, respectively, to officers and other key employees under the WEC Energy Group Performance Unit Plan.

Performance units with an intrinsic value of $10.2 million, $20.2 million, and $27.7 million were settled during 2023, 2022, and 2021, respectively. The actual tax benefit from the distribution of performance units for the same years was $2.6 million, $5.1 million, and $6.8 million, respectively.

At December 31, 2023, we had 412,448 performance units outstanding, including dividend equivalents. A liability of $10.0 million was recorded on our balance sheet at December 31, 2023 related to these outstanding units. As of December 31, 2023, approximately $12.8

million of unrecognized compensation cost related to unvested and outstanding performance units was expected to be recognized over the next 1.9 years on a weighted-average basis.

During the first quarter of 2024, we settled performance units with an intrinsic value of $1.0 million. The actual tax benefit from the distribution of these awards was $0.2 million. In January 2024, the Compensation Committee also awarded 196,256 performance units to certain of our officers and other key employees under its normal schedule of awarding long-term incentive compensation.

Restrictions

Our ability as a holding company to pay common stock dividends primarily depends on the availability of funds received from our utility subsidiaries, We Power, Bluewater, ATC Holding, and WECI. Various financing arrangements and regulatory requirements impose certain restrictions on the ability of our subsidiaries to transfer funds to us in the form of cash dividends, loans, or advances. All of our utility subsidiaries, with the exception of UMERC and MGU, are prohibited from loaning funds to us, either directly or indirectly.

In accordance with their most recent rate orders, WE, WPS, and WG may not pay common dividends above the test year forecasted amounts reflected in their respective rate cases, if it would cause their average common equity ratio, on a financial basis, to fall below their authorized level of 53.0%. A return of capital in excess of the test year amount can be paid by each company at the end of the year provided that their respective average common equity ratios do not fall below the authorized level.

WE may not pay common dividends to us under WE's Restated Articles of Incorporation if any dividends on its outstanding preferred stock have not been paid. In addition, pursuant to the terms of WE's 3.60% Serial Preferred Stock, WE's ability to declare common dividends would be limited to 75% or 50% of net income during a 12-month period if its common stock equity to total capitalization, as defined in the preferred stock designation, is less than 25% and 20%, respectively.

NSG's long-term debt obligations contain provisions and covenants restricting the payment of cash dividends and the purchase or redemption of its capital stock.

The long-term debt obligations of UMERC, Bluewater Gas Storage, and ATC Holding contain a provision requiring them to maintain a total funded debt to capitalization ratio of 65% or less.

WECI Wind Holding I's and WECI Wind Holding II's long-term debt obligations contain various conditions that must be met prior to them making any cash distributions. Included in these provisions is a requirement to maintain a debt service coverage ratio of 1.2 or greater for the 12-month period prior to the distribution.

WEC Energy Group has the option to defer interest payments on its 2007 Junior Notes, from time to time, for one or more periods of up to 10 consecutive years per period. During any period in which it defers interest payments, it may not declare or pay any dividends or distributions on, or redeem, repurchase or acquire, its common stock.

See Note 13, Short-Term Debt and Lines of Credit, for discussion of certain financial covenants related to short-term debt obligations.

As of December 31, 2023, restricted net assets of our consolidated subsidiaries totaled approximately $11.4 billion. Our equity in undistributed earnings of investees accounted for by the equity method was approximately $525 million.

We do not believe that these restrictions will materially affect our operations or limit any dividend payments in the foreseeable future.

Share Purchases

During the years ended December 31, 2023, 2022, and 2021, we instructed our independent agents to purchase shares on the open market to fulfill obligations under various stock-based employee benefit and compensations plans and to provide shares to participants in our dividend reinvestment and stock purchase plan. As a result, no new shares of common stock were issued during these years. As of January 1, 2024, we began issuing new shares of common stock to fulfill our obligations under these plans.

The following is a summary of shares purchased to fulfill exercised stock options and restricted stock awards during the years ended December 31:

(in millions)	2023	2022	2021
Shares purchased	**0.2**	0.7	0.4
Cost of shares purchased	**$ 16.6**	$ 69.2	$ 33.1

Common Stock Dividends

During the year ended December 31, 2023, our Board of Directors declared common stock dividends which are summarized below:

Date Declared	Date Payable	Per Share	Period
January 19, 2023	March 1, 2023	$0.78	First quarter
April 20, 2023	June 1, 2023	$0.78	Second quarter
July 20, 2023	September 1, 2023	$0.78	Third quarter
October 19, 2023	December 1, 2023	$0.78	Fourth quarter

On January 18, 2024, our Board of Directors declared a quarterly cash dividend of $0.835 per share, which equates to an annual dividend of $3.34 per share. The dividend is payable on March 1, 2024, to shareholders of record on February 14, 2024. In addition, the Board of Directors affirmed our dividend policy that continues to target a dividend payout ratio of 65-70% of earnings.

NOTE 12—PREFERRED STOCK

The following table shows preferred stock authorized and outstanding at December 31, 2023 and 2022:

(in millions, except share and per share amounts)	Shares Authorized	Shares Outstanding	Redemption Price Per Share	Total
WEC Energy Group				
$0.01 par value Preferred Stock	**15,000,000**	**—**	**—**	**$ —**
WE				
$100 par value, Six Per Cent. Preferred Stock	**45,000**	**44,498**	**—**	**4.4**
$100 par value, Serial Preferred Stock 3.60% Series	**2,286,500**	**260,000**	**$ 101**	**26.0**
$25 par value, Serial Preferred Stock	**5,000,000**	**—**	**—**	**—**
WPS				
$100 par value, Preferred Stock	**1,000,000**	**—**	**—**	**—**
PGL				
$100 par value, Cumulative Preferred Stock	**430,000**	**—**	**—**	**—**
NSG				
$100 par value, Cumulative Preferred Stock	**160,000**	**—**	**—**	**—**
Total				**$ 30.4**

NOTE 13—SHORT-TERM DEBT AND LINES OF CREDIT

The following table shows our short-term borrowings and their corresponding weighted-average interest rates as of December 31:

(in millions, except percentages)		2023		2022
Commercial paper				
Amount outstanding at December 31	**$**	**2,017.2**	$	1,643.5
Average interest rate on amounts outstanding at December 31		**5.49 %**		4.64 %
Operating expense loans				
Amount outstanding at December 31 [1]	**$**	**3.7**	$	3.6

[1] Coyote Ridge, Tatanka Ridge, and Jayhawk have entered into operating expense loans. In accordance with their limited liability company operating agreements, they received loans from the holders of their noncontrolling interests in proportion to their ownership interests.

Our average amount of commercial paper borrowings based on daily outstanding balances during 2023, was $1,196.8 million with a weighted-average interest rate during the period of 5.29%.

WEC Energy Group, WE, WPS, WG, and PGL have entered into bank back-up credit facilities to maintain short-term credit liquidity which, among other terms, require them to maintain, subject to certain exclusions, a total funded debt to capitalization ratio of 70.0%, 65.0%, 65.0%, 65.0%, and 65.0% or less, respectively. As of December 31, 2023, all companies were in compliance with their respective ratio.

The information in the table below relates to our revolving credit facilities used to support our commercial paper borrowing programs, including remaining available capacity under these facilities as of December 31:

(in millions)	**Maturity**	**2023**
Revolving credit facility (WEC Energy Group) [1]	September 2026	**$ 1,500.0**
Revolving credit facility (WEC Energy Group)	October 2024	**200.0**
Revolving credit facility (WE) [1]	September 2026	**500.0**
Revolving credit facility (WPS) [1]	September 2026	**400.0**
Revolving credit facility (WG) [1]	September 2026	**350.0**
Revolving credit facility (PGL) [1]	September 2026	**350.0**
Total short-term credit capacity		**$ 3,300.0**
Less:		
Letters of credit issued inside credit facilities		**$ 2.3**
Commercial paper outstanding		**2,017.2**
Available capacity under existing facilities		**$ 1,280.5**

[1] These revolving credit facilities have a renewal provision for two extensions, subject to lender approval. Each extension is for a period of one year.

The bank back-up credit facilities contain customary covenants, including certain limitations on the respective companies' ability to sell assets. The credit facilities also contain customary events of default, including payment defaults, material inaccuracy of representations and warranties, covenant defaults, bankruptcy proceedings, certain judgments, Employee Retirement Income Security Act of 1974 defaults, and change of control. In addition, pursuant to the terms of WEC Energy Group's credit agreement, we must ensure that certain of our subsidiaries comply with several of the covenants contained therein.

NOTE 14—LONG-TERM DEBT

The following table is a summary of our long-term debt outstanding (excluding finance leases) as of December 31:

(in millions)	2023 Maturity Date	2023 Weighted Average Interest Rate	2023 Balance	2022 Weighted Average Interest Rate	2022 Balance
WEC Energy Group Senior Notes (unsecured) (1)	2024-2033	**3.68 %**	**$ 5,320.0**	2.44 %	$ 3,970.0
WEC Energy Group Junior Notes (unsecured) (1) (2)	2067	**7.75 %**	**500.0**	6.72 %	500.0
WE Debentures (unsecured)	2024-2095	**4.22 %**	**3,285.0**	4.22 %	3,285.0
WEPCo Environmental Trust (secured, nonrecourse) (5) (9)	2024-2035	**1.58 %**	**97.0**	1.58 %	105.9
WPS Senior Notes (unsecured)	2025-2051	**4.11 %**	**1,975.0**	4.11 %	1,975.0
WG Debentures (unsecured)	2024-2046	**3.35 %**	**790.0**	3.35 %	790.0
Integrys Junior Notes (unsecured)	2073	**— %**	**—**	6.00 %	221.4
PGL First and Refunding Mortgage Bonds (secured) (3)	2024-2047	**3.53 %**	**2,070.0**	3.41 %	1,970.0
NSG First Mortgage Bonds (secured) (4)	2027-2043	**3.81 %**	**177.0**	3.56 %	157.0
MERC Senior Notes (unsecured)	2025-2047	**3.04 %**	**210.0**	3.04 %	210.0
MGU Senior Notes (unsecured)	2025-2047	**3.18 %**	**150.0**	3.18 %	150.0
UMERC Senior Notes (unsecured)	2029	**3.26 %**	**160.0**	3.26 %	160.0
Bluewater Gas Storage Senior Notes (unsecured) (5)	2024-2047	**3.76 %**	**109.8**	3.76 %	112.6
ATC Holding Senior Notes (unsecured)	2025-2030	**4.05 %**	**475.0**	4.05 %	475.0
We Power Subsidiaries Notes (secured, nonrecourse) (5) (6)	2024-2041	**5.65 %**	**856.4**	5.62 %	896.5
WECC Notes (unsecured)	2028	**6.94 %**	**50.0**	6.94 %	50.0
WECI Wind Holding I Senior Notes (secured, nonrecourse) (5) (7)	2024-2032	**2.75 %**	**307.7**	2.75 %	332.1
WECI Wind Holding II Senior Notes (secured, nonrecourse) (5) (8)	2024-2031	**6.38 %**	**191.4**	6.38 %	199.3
Total			**16,724.3**		15,559.8
Integrys acquisition fair value adjustment			**—**		1.2
Jayhawk acquisition			**7.5**		7.3
Unamortized debt issuance costs			**(80.2)**		(81.8)
Unamortized discount, net and other			**(20.5)**		(22.3)
Total long-term debt, including current portion (10)			**16,631.1**		15,464.2
Current portion of long-term debt			**(1,264.2)**		(808.5)
Total long-term debt			**$15,366.9**		$ 14,655.7

(1) In connection with our outstanding 2007 Junior Notes, we executed an RCC, which we amended on June 29, 2015, for the benefit of persons that buy, hold, or sell a specified series of our long-term indebtedness (covered debt). Our 6.20% Senior Notes due April 1, 2033 have been designated as the covered debt under the RCC. The RCC provides that we may not redeem, defease, or purchase, and that our subsidiaries may not purchase, any 2007 Junior Notes on or before May 15, 2037, unless, subject to certain limitations described in the RCC, we have received a specified amount of proceeds from the sale of qualifying securities. The terms of the RCC have been previously satisfied.

(2) Variable interest rates reset quarterly. The rates were 7.75% and 6.72% as of December 31, 2023 and 2022, respectively.

(3) PGL's First Mortgage Bonds are subject to the terms and conditions of PGL's First Mortgage Indenture dated January 2, 1926, as supplemented. Under the terms of the Indenture, substantially all property owned by PGL is pledged as collateral for these outstanding debt securities.

PGL has used certain First Mortgage Bonds to secure tax exempt interest rates. The Illinois Finance Authority has issued Tax Exempt Bonds, and the proceeds from the sale of these bonds were loaned to PGL. In return, PGL issued $100 million of collateralized First Mortgage Bonds.

(4) NSG's First Mortgage Bonds are subject to the terms and conditions of NSG's First Mortgage Indenture dated April 1, 1955, as supplemented. Under the terms of the Indenture, substantially all property owned by NSG is pledged as collateral for these outstanding debt securities.

(5) The long-term debt of Bluewater, WECI Wind Holding I, WECI Wind Holding II, WEPCo Environmental Trust, and We Power's subsidiaries requires periodic principal payments.

(6) We Power's subsidiaries' senior notes are secured by a collateral assignment of the leases between We Power's subsidiaries and WE related to PWGS and ERGS, as applicable.

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(7) WECI Wind Holding I's Senior Notes are secured by a first priority security interest in the ownership interest of its subsidiaries, as well as a pledge of equity in WECI Wind Holding I.

(8) WECI Wind Holding II's Senior Notes are secured by a first priority security interest in the ownership interest of its subsidiaries, as well as a pledge of equity in WECI Wind Holding II.

(9) WEPCo Environmental Trust’s ETBs are secured by a pledge of and lien on environmental control property, which includes the right to impose, collect and receive a non-bypassable environmental control charge paid by all of WE's retail electric distribution customers, the right to obtain true-up adjustments of the environmental control charges, and all revenues or other proceeds arising from those rights and interests. See Note 23, Variable Interest Entities, for more information.

(10) The amount of long-term debt on our balance sheets includes finance lease obligations of $145.9 million and $183.2 million at December 31, 2023 and 2022, respectively.

We amortize debt premiums, discounts, and debt issuance costs over the life of the debt and we include the costs in interest expense.

In March 2022, President Biden signed into law the Adjustable Interest Rate (LIBOR) Act. This Act established a uniform process, on a nationwide basis, for replacing LIBOR in certain contracts that did not provide a clearly defined or practicable replacement benchmark rate. Under the LIBOR Act, the Federal Reserve Board was required to determine an appropriate benchmark replacement based on SOFR, with applicable credit spread adjustments. In December 2022, the Federal Reserve Board adopted the final rule to implement the LIBOR Act and established the SOFR-based benchmark replacements. No contract modifications were required for qualifying contracts under the LIBOR Act as the benchmark replacement automatically overrode the existing contract language and became the applicable benchmark after June 30, 2023.

For our $500 million of 2007 Junior Notes, starting August 15, 2023, the benchmark replacement rate is the applicable tenor of three-month CME Term SOFR, as administered by the CME Group Benchmark Administration, and includes a credit spread adjustment of 0.26161% per annum. In accordance with the LIBOR Act, no contract modifications were required for our 2007 Junior Notes as the references to LIBOR were replaced by operation of law.

WEC Energy Group, Inc.

In January 2023, we issued $650.0 million of 4.75% Senior Notes due January 9, 2026, and $450.0 million of 4.75% Senior Notes due January 15, 2028, and used the net proceeds to repay short-term debt and for other corporate purposes.

In April 2023, we issued an additional $350.0 million of our 4.75% Senior Notes due January 9, 2026, and used the net proceeds to repay short-term debt and for other corporate purposes.

In September 2023, we issued $600.0 million of 5.60% Senior Notes due September 12, 2026, and used the net proceeds to repay short-term debt and for other corporate purposes.

Subsequently, we repaid the outstanding principal and accrued interest on our $700.0 million of 0.55% Senior Notes that matured on September 15, 2023.

In January and February, 2024, pursuant to a tender offer, we purchased $122.1 million aggregate principal amount of the $500.0 million outstanding of our 2007 Junior Notes for $115.2 million with proceeds from issuing commercial paper. We recorded a $6.9 million gain related to the early settlement.

Integrys Holding, Inc.

In March 2023, Integrys repurchased $18.9 million of the $221.4 million outstanding of its 6.00% 2013 Junior Notes, prior to maturity for $18.6 million. Integrys recognized an insignificant gain on the early extinguishment of debt due to the debt being repurchased at a discount.

On August 1, 2023, Integrys redeemed the remaining $202.5 million outstanding of its 6.00% 2013 Junior Notes, prior to maturity at par value.

The Peoples Gas Light and Coke Company

In November 2023, PGL issued $100.0 million of 5.82% First and Refunding Mortgage Bonds, Series NNN due April 1, 2029, and used the net proceeds for general corporate purposes, including capital expenditures and the refinancing of short-term debt.

North Shore Gas Company

In November 2023, NSG issued $20.0 million of 5.82% First Mortgage Bonds, Series T due April 1, 2029, and used the net proceeds for general corporate purposes, including capital expenditures and the refinancing of short-term debt.

Maturities of Long-Term Debt Outstanding

The following table shows the long-term debt securities (excluding finance leases) maturing within one year of December 31, 2023:

(in millions)	Interest Rate	Maturity Date [(1)]	Principal Amount
WEC Energy Group Senior Notes (unsecured)	0.80%	March	$ 600.0
WG Debentures (unsecured)	2.38%	November	150.0
PGL Bonds (secured)	2.64%	November	75.0
WE Debentures (unsecured)	2.05%	December	300.0
WEPCo Environmental Trust (secured, nonrecourse)	1.58%	Semi-annually	9.0
Bluewater Gas Storage Senior Notes (unsecured)	3.76%	Semi-annually	2.9
We Power Subsidiaries Notes – PWGS (secured, nonrecourse)	4.91%	Monthly	8.0
We Power Subsidiaries Notes – ERGS (secured, nonrecourse)	5.209%	Semi-annually	15.5
We Power Subsidiaries Notes – ERGS (secured, nonrecourse)	4.673%	Semi-annually	11.7
We Power Subsidiaries Notes – PWGS (secured, nonrecourse)	6.00%	Monthly	7.0
WECI Wind Holding I Senior Notes (secured, nonrecourse)	2.75%	Semi-annually	61.3
WECI Wind Holding II Senior Notes (secured, nonrecourse)	6.38%	Semi-annually	23.8
Total			$ 1,264.2

(1) Maturity dates listed as semi-annually and monthly are associated with debt that requires periodic principal payments.

The following table shows the future maturities of our long-term debt outstanding (excluding obligations under finance leases) as of December 31, 2023:

(in millions)	Payments
2024	$ 1,264.2
2025	1,685.5
2026	1,726.8
2027	1,230.7
2028	2,307.2
Thereafter	8,509.9
Total	$ 16,724.3

Certain long-term debt obligations contain financial and other covenants related to payment of principal and interest when due, maintaining certain total funded debt to capitalization ratios, and various other obligations. Failure to comply with these covenants could result in an event of default, which could result in the acceleration of outstanding debt obligations.

NOTE 15—LEASES

Obligations Under Operating Leases

We have recorded right of use assets and lease liabilities primarily associated with the following operating leases:

- Leases of office space, primarily related to several floors we are leasing in the Aon Center office building in Chicago, Illinois, through April 2029.
- Land we are leasing related to our Rothschild biomass plant through June 2051.

- Rail cars we are leasing to transport coal to various generating facilities through June 2027.
- Land we are leasing related to our utility and non-utility solar generation projects through May 2073.

The operating leases generally require us to pay property taxes, insurance premiums, and operating and maintenance costs associated with the leased property. Certain of our leases contain options for early termination or to renew past the initial term, as set forth in the lease agreements. These options are included in our calculation of the lease obligations if it is reasonably certain that they will be exercised.

Obligations Under Finance Leases

In accordance with ASC Subtopic 980-842, Regulated Operations – Leases (Subtopic 980-842), the timing of expense recognition associated with our finance leases is modified to conform to the rate treatment. Amortization of the right-of-use asset is modified so that the total of the imputed interest and amortization costs equals the lease expense that is allowed for rate-making purposes. The difference between this lease expense and the sum of imputed interest and unadjusted amortization costs calculated under Topic 842 is deferred as a regulatory asset on our balance sheets in accordance with Subtopic 980-842.

Land Leases – Utility Solar Generation

We have various land leases related to our investments in utility solar generation. Each lease has an initial term and one or more optional extensions. We expect the optional extensions to be exercised, and, as a result, all of the land leases are being amortized over an extended term of approximately 50 years. Once a solar project achieves commercial operation, the lease liability is remeasured to reflect the final total acres being leased. Our payments related to these leases are being recovered through rates.

Power Purchase Commitment

In 1997, WE entered into a 25-year PPA with LSP-Whitewater Limited Partnership. The contract, for 236.5 MWs of firm capacity from a natural gas-fired cogeneration facility, included zero minimum energy requirements. The PPA expired on May 31, 2022; however, in November 2021, WE entered into a tolling agreement with LSP-Whitewater Limited Partnership that commenced on June 1, 2022. Concurrent with the execution of the tolling agreement, WE and WPS entered into an asset purchase agreement to acquire the natural gas-fired cogeneration facility and the acquisition closed effective January 1, 2023. See Note 2, Acquisitions, for more information. Both the PPA and the tolling agreement were accounted for as a finance lease prior to the acquisition.

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Amounts Recognized in the Financial Statements and Other Information

The components of lease expense and supplemental cash flow information related to our leases for the years ended December 31 are as follows:

(in millions)	2023	2022	2021
Finance lease expense			
Amortization of right of use assets [1]	**$ —**	$ 6.0	$ 8.1
Interest on lease liabilities [2]	**0.8**	0.9	1.6
Operating lease expense [3]	**4.7**	6.1	3.4
Short-term lease expense [3]	**1.2**	0.9	0.2
Total lease expense	**$ 6.7**	$ 13.9	$ 13.3
Other information			
Cash paid for amounts included in the measurement of lease liabilities			
Operating cash flows from finance leases	**$ 0.8**	$ 0.9	$ 1.6
Operating cash flows from operating leases	**6.8**	5.7	5.3
Financing cash flows from finance leases	**—**	6.0	8.1
Non-cash activities:			
Right of use assets obtained in exchange for finance lease liabilities [4]	**$ 32.8**	$ 57.6	$ 73.6
Right of use assets obtained in exchange for operating lease liabilities	**18.3**	—	0.5
Weighted-average remaining lease term – finance leases	**49.4 years**	30.0 years	20.5 years
Weighted-average remaining lease term – operating leases	**22.4 years**	12.0 years	12.5 years
Weighted-average discount rate – finance lease [5]	**5.3 %**	3.9 %	2.4 %
Weighted average discount rate – operating leases [5]	**5.8 %**	3.4 %	3.4 %

[1] Amortization of right of use assets was included as a component of depreciation and amortization expense.

[2] Interest on lease liabilities was included as a component of interest expense.

[3] Operating and short-term lease expense were included as a component of other operation and maintenance expense.

[4] Amounts are net of any reductions to right of use assets and finance lease liabilities resulting from remeasurements.

(5) Because our leases do not provide an implicit rate of return, we used the fully collateralized incremental borrowing rates based upon information available for similarly rated companies in determining the present value of lease payments.

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The following table summarizes our finance and operating lease right of use assets and obligations at December 31:

(in millions)	2023	2022	Balance Sheet Location
Right of use assets			
Operating lease right of use assets, net	**$ 32.0**	$ 15.7	Other long-term assets
Finance lease right of use assets, net			
Power purchase commitment [1]	**$ —**	$ 71.8	
Land leases – utility solar generation	**132.7**	102.4	
Other	**1.1**	1.1	
Total finance lease right of use assets, net [2]	**$ 133.8**	$ 175.3	Property, plant, and equipment, net
Lease obligations			
Current operating lease liabilities	**$ 4.7**	$ 4.0	Other current liabilities
Long-term operating lease liabilities	**$ 38.8**	$ 25.4	Other long-term liabilities
Current finance lease liabilities			
Power purchase commitment [1]	**$ —**	$ 72.7	Current portion of long-term debt
Long-term finance lease liabilities			
Land leases – utility solar generation	**$ 144.8**	$ 109.3	
Other	**1.1**	1.2	
Total long-term finance lease liabilities	**$ 145.9**	$ 110.5	Long-term debt

(1) Effective January 1, 2023, WE and WPS closed on the acquisition of Whitewater. See discussion above for more information.

(2) Amounts are net of accumulated amortization of $6.1 million and $146.3 million at December 31, 2023 and 2022, respectively.

Future minimum lease payments under our operating and finance leases and the present value of our net minimum lease payments as of December 31, 2023, were as follows:

(in millions)	Total Operating Leases	Land Leases - Utility Solar Generation	Other	Total Finance Leases
2024	$ 6.4	$ 4.7	$ 0.1	$ 4.8
2025	5.6	6.0	0.1	6.1
2026	5.8	6.1	0.1	6.2
2027	5.7	6.2	0.1	6.3
2028	5.5	6.4	0.1	6.5
Thereafter	71.0	465.8	2.5	468.3
Total minimum lease payments	100.0	495.2	3.0	498.2
Less: Interest	(56.5)	(350.4)	(1.9)	(352.3)
Present value of minimum lease payments	43.5	144.8	1.1	145.9
Less: Short-term lease liabilities	(4.7)	—	—	—
Long-term lease liabilities	$ 38.8	$ 144.8	$ 1.1	$ 145.9

As of February 22, 2024, we have not entered into any material leases that have not yet commenced.

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NOTE 16—INCOME TAXES

Income Tax Expense

The following table is a summary of income tax expense for the years ended December 31:

(in millions)	2023	2022	2021
Current tax expense (benefit)	**$ (14.8)**	$ 50.2	$ 93.9
Deferred income taxes, net	**229.9**	278.5	111.0
ITCs	**(10.5)**	(5.8)	(4.6)
Total income tax expense	**$ 204.6**	$ 322.9	$ 200.3

Statutory Rate Reconciliation

The provision for income taxes for each of the years ended December 31 differs from the amount of income tax determined by applying the applicable United States statutory federal income tax rate to income before income taxes as a result of the following:

	2023		2022		2021	
(in millions)	Amount	Effective Tax Rate	Amount	Effective Tax Rate	Amount	Effective Tax Rate
Statutory federal income tax	**$ 322.6**	**21.0 %**	$ 363.5	21.0 %	$ 315.1	21.0 %
State income taxes net of federal tax benefit	**94.3**	**6.1 %**	109.7	6.3 %	96.1	6.4 %
PTCs, net	**(168.2)**	**(10.9)%**	(107.6)	(6.2)%	(81.3)	(5.4)%
Federal excess deferred tax amortization [(1)]	**(37.6)**	**(2.4)%**	(36.9)	(2.1)%	(37.3)	(2.5)%
AFUDC-Equity	**(12.4)**	**(0.8)%**	(6.2)	(0.4)%	(3.8)	(0.3)%
Federal excess deferred tax amortization – Wisconsin unprotected [(2)]	**(0.8)**	**(0.1)%**	(0.8)	— %	(77.9)	(5.2)%
Other, net	**6.7**	**0.4 %**	1.2	— %	(10.6)	(0.6)%
Total income tax expense	**$ 204.6**	**13.3 %**	$ 322.9	18.6 %	$ 200.3	13.4 %

(1) The Tax Legislation required our regulated utilities to remeasure their deferred income taxes and we began to amortize the resulting excess protected deferred income taxes beginning in 2018 in accordance with normalization requirements. The decrease in income tax expense related to the amortization of the deferred tax benefits is offset by a decrease in revenue as the benefits are returned to customers, resulting in no impact on net income.

(2) In accordance with the rate order received from the PSCW in December 2019, our Wisconsin utilities amortized these unprotected deferred tax benefits over periods ranging from two years to four years, to reduce near-term rate impacts to their customers. The decrease in income tax expense related to the amortization of the deferred tax benefits is offset by a decrease in revenue as the benefits are returned to customers, resulting in no impact on net income.

See Note 26, Regulatory Environment, for more information about the impact of the Tax Legislation and the Wisconsin rate orders.

Deferred Income Tax Assets and Liabilities

The components of deferred income taxes as of December 31 were as follows:

(in millions)	2023	2022
Deferred tax assets		
Tax gross up – regulatory items	**$ 438.6**	$ 459.0
Future tax benefits	**160.7**	187.7
Deferred revenues	**84.7**	86.8
Other	**168.3**	190.2
Total deferred tax assets	**852.3**	923.7
Valuation allowance	**(5.0)**	(1.2)
Net deferred tax assets	**$ 847.3**	$ 922.5
Deferred tax liabilities		
Property-related	**$ 4,198.0**	$ 4,072.5
Investment in affiliates	**915.1**	839.7
Employee benefits and compensation	**227.2**	219.5
Deferred costs – plant retirements	**199.6**	212.8
Other	**225.9**	203.6
Total deferred tax liabilities	**5,765.8**	5,548.1
Deferred tax liability, net	**$ 4,918.5**	$ 4,625.6

Consistent with ratemaking treatment, deferred taxes related to our regulated utilities in the table above are offset for temporary differences that have related regulatory assets and liabilities.

The components of net deferred tax assets associated with federal and state tax benefit carryforwards as of December 31, 2023 and 2022 are summarized in the tables below:

2023 (in millions)	Gross Value	Deferred Tax Effect	Valuation Allowance	Earliest Year of Expiration
Future tax benefits as of December 31, 2023				
Federal tax credit	**$ —**	**$ 153.0**	**$ —**	**2042**
State net operating loss	**62.6**	**3.8**	**(1.1)**	**2032**
Other state benefits	**—**	**3.9**	**(3.9)**	**2024**
Balance as of December 31, 2023	**$ 62.6**	**$ 160.7**	**$ (5.0)**	

2022 (in millions)	Gross Value		Deferred Tax Effect		Valuation Allowance	Earliest Year of Expiration
Future tax benefits as of December 31, 2022						
Federal tax credit	$	—	$ 176.4	$	—	2041
State net operating loss		72.6	4.5		(1.2)	2032
Other state benefits		—	6.8		—	2023
Balance as of December 31, 2022	$	72.6	$ 187.7	$	(1.2)	

Unrecognized Tax Benefits

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

(in millions)	2023	2022	2021
Balance as of January 1	**$ 6.3**	$ 6.8	$ 11.9
Additions for tax positions of prior years	**0.2**	0.3	—
Additions based on tax positions related to the current year	**—**	0.4	1.6
Reductions for tax positions of prior years	**(1.9)**	(1.2)	(6.7)
Balance as of December 31	**$ 4.6**	$ 6.3	$ 6.8

The amount of unrecognized tax benefits as of December 31, 2023 and 2022, excludes deferred tax assets related to uncertainty in income taxes of $1.1 million and $1.3 million, respectively. As of December 31, 2023 and 2022, the net amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate for continuing operations was $3.6 million and $5.1 million, respectively.

Interest accrued related to unrecognized tax benefits is as follows:

(in millions)	2023	2022	2021
Balance as of January 1	**$ 0.5**	$ 0.1	$ 0.5
Interest expense (income) related to unrecognized tax benefits	**0.1**	0.4	(0.4)
Balance as of December 31	**$ 0.6**	$ 0.5	$ 0.1

For the years ended December 31, 2023, 2022, and 2021, we recognized no penalties related to unrecognized tax benefits in our consolidated income statements. At December 31, 2023 and 2022, we had no amounts accrued for penalties related to unrecognized tax benefits.

Although analysis of our unrecognized tax benefits is ongoing, the potential estimated decrease in the total amounts of unrecognized tax benefits within the next 12 months is approximately $0.6 million associated with statutes of limitations on certain tax years. We do not anticipate any significant increases in the total amounts of unrecognized tax benefits within the next 12 months.

We file income tax returns in the United States federal jurisdiction and state tax returns based on income in our major state operating jurisdictions of Wisconsin, Illinois, Michigan, and Minnesota. We also file tax returns in other state and local jurisdictions with varying statutes of limitations. As of December 31, 2023, with a few exceptions, we were subject to examination by federal and state or local tax authorities for the 2019 through 2023 tax years in our major operating jurisdictions as follows:

Jurisdiction	Years
Federal	2020–2023
Illinois	2019–2023
Michigan	2019–2023
Minnesota	2019–2023
Wisconsin	2019–2023

NOTE 17—FAIR VALUE MEASUREMENTS

The following tables summarize our financial assets and liabilities that were accounted for at fair value on a recurring basis, categorized by level within the fair value hierarchy:

(in millions)	December 31, 2023 Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	$ 2.2	$ 8.3	$ —	$ 10.5
FTRs and TCRs	—	—	7.2	7.2
Coal contracts	—	0.3	—	0.3
Total derivative assets	$ 2.2	$ 8.6	$ 7.2	$ 18.0
Investments held in rabbi trust	$ 51.7	$ —	$ —	$ 51.7
Derivative liabilities				
Natural gas contracts	$ 70.1	$ 16.0	$ —	$ 86.1
Coal contracts	—	20.3	—	20.3
Total derivative liabilities	$ 70.1	$ 36.3	$ —	$ 106.4

(in millions)	December 31, 2022 Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	$ 16.3	$ 16.2	$ —	$ 32.5
FTRs	—	—	7.8	7.8
Coal contracts	—	34.5	—	34.5
Total derivative assets	$ 16.3	$ 50.7	$ 7.8	$ 74.8
Investments held in rabbi trust	$ 50.9	$ —	$ —	$ 50.9
Derivative liabilities				
Natural gas contracts	$ 81.4	$ 15.2	$ —	$ 96.6

The derivative assets and liabilities listed in the tables above include options, futures, physical commodity contracts, and other instruments used to manage market risks related to changes in commodity prices. They also include FTRs and TCRs, which are used at our electric utilities and certain of our non-utility wind parks to manage electric transmission congestion costs in the MISO Energy Markets and the SPP Integrated Marketplace, respectively.

We hold investments in the Integrys rabbi trust. These investments are used to fund participants' benefits under the Integrys deferred compensation plan and certain Integrys non-qualified pension plans. These investments are included in other long-term assets on our balance sheets. During the years ended December 31, 2023 and 2021, the net unrealized gains included in earnings related to the investments held at the end of the period were $10.0 million and $16.0 million, respectively. For the year ended December 31, 2022, we recorded $12.7 million of net unrealized losses in earnings related to the investments held at the end of the period.

The following table summarizes the changes to derivatives classified as Level 3 in the fair value hierarchy at December 31:

(in millions)	2023	2022	2021
Balance at the beginning of the period	**$ 7.8**	$ 2.4	$ 2.4
Purchases	**21.0**	23.7	6.1
Realized and unrealized net gains (losses) included in earnings (1)	**(0.5)**	0.5	—
Settlements	**(21.1)**	(18.8)	(6.1)
Balance at the end of the period	**$ 7.2**	$ 7.8	$ 2.4
Unrealized net gains (losses) included in earnings attributable to Level 3 derivatives held at the end of the reporting period (1)	**$ 0.5**	$ (0.4)	$ —

(1) Amounts relate to FTRs and TCRs included in our non-utility energy infrastructure segment. These realized and unrealized net gains and losses are recorded in operating revenues on our income statements.

Fair Value of Financial Instruments

The following table shows the financial instruments included on our balance sheets that are not recorded at fair value at December 31:

	2023		2022	
(in millions)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Preferred stock of subsidiary	**$ 30.4**	**$ 21.4**	$ 30.4	$ 22.7
Long-term debt, including current portion (1)	**16,631.1**	**15,564.3**	15,464.2	13,921.3

(1) The carrying amount of long-term debt excludes finance lease obligations of $145.9 million and $183.2 million at December 31, 2023 and 2022, respectively.

The fair values of our long-term debt and preferred stock are categorized within Level 2 of the fair value hierarchy.

NOTE 18—DERIVATIVE INSTRUMENTS

Derivative assets and liabilities are included in the other current and other long-term line items on our balance sheets. The following table shows our derivative assets and derivative liabilities. None of the derivatives shown below were designated as hedging instruments.

	December 31, 2023		December 31, 2022	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Current				
Natural gas contracts	**$ 10.4**	**$ 78.1**	$ 32.5	$ 88.2
FTRs and TCRs	**7.2**	**—**	7.8	—
Coal contracts	**0.3**	**10.9**	18.9	—
Total current	**17.9**	**89.0**	59.2	88.2
Long-term				
Natural gas contracts	**0.1**	**8.0**	—	8.4
Coal contracts	**—**	**9.4**	15.6	—
Total long-term	**0.1**	**17.4**	15.6	8.4
Total	**$ 18.0**	**$ 106.4**	$ 74.8	$ 96.6

Realized gains and losses on derivatives used in our regulatory utility operations are recorded in cost of sales upon settlement; however, they may be subsequently deferred for future rate recovery or refund as the gains and losses are included in our utilities' fuel and natural gas cost recovery mechanisms. Realized gains and losses on FTRs and TCRs used in our non-utility operations are recorded in operating revenues on the income statements. Our estimated notional sales volumes and realized gains and losses were as follows for the years ended:

	December 31, 2023		December 31, 2022		December 31, 2021	
(in millions)	Volumes	Gains (Losses)	Volumes	Gains	Volumes	Gains
Natural gas contracts	**198.0 Dth**	**$ (259.1)**	183.3 Dth	$ 299.5	197.6 Dth	$ 136.5
FTRs and TCRs	**30.2 MWh**	**25.9**	27.2 MWh	11.8	28.2 MWh	17.7
Total		**$ (233.2)**		$ 311.3		$ 154.2

At December 31, 2023 and 2022, we had posted cash collateral of $100.3 million and $122.4 million, respectively.

The following table shows derivative assets and derivative liabilities if derivative instruments by counterparty were presented net on our balance sheets:

	December 31, 2023		December 31, 2022	
(in millions)	**Derivative Assets**	**Derivative Liabilities**	**Derivative Assets**	**Derivative Liabilities**
Gross amount recognized on the balance sheet	**$ 18.0**	**$ 106.4**	$ 74.8	$ 96.6
Gross amount not offset on the balance sheet	**(3.1)**	**(71.0)** [(1)]	(17.5)	(82.5) [(2)]
Net amount	**$ 14.9**	**$ 35.4**	$ 57.3	$ 14.1

(1) Includes cash collateral posted of $67.9 million.

(2) Includes cash collateral posted of $65.0 million.

Cash Flow Hedges

Until their expiration on November 15, 2021, we had two interest rate swaps with a combined notional value of $250.0 million to hedge the variable interest rate risk associated with our 2007 Junior Notes. The swaps provided a fixed interest rate of 4.9765% on $250.0 million of the $500.0 million of outstanding 2007 Junior Notes. As these swaps qualified for cash flow hedge accounting treatment, the related gains and losses were deferred in accumulated other comprehensive loss and were amortized to interest expense as interest was accrued on the 2007 Junior Notes.

We also previously entered into forward interest rate swap agreements to mitigate the interest rate exposure associated with the issuance of long-term debt related to the acquisition of Integrys. These swap agreements were settled in 2015, and we continue to amortize amounts out of accumulated other comprehensive loss into interest expense over the periods in which the interest costs are recognized in earnings.

The derivative gains and losses related to these swap agreements recognized in other comprehensive income and reclassified from accumulated other comprehensive loss to interest expense during the years ended December 31, 2023, 2022, and 2021 were not significant. At December 31, 2023, the amount expected to be reclassified from accumulated other comprehensive loss to interest expense over the next twelve months was also not significant.

NOTE 19—GUARANTEES

The following table shows our outstanding guarantees:

(in millions)	Total Amounts Committed at December 31, 2023	Expiration: Less Than 1 Year	Expiration: 1 to 3 Years	Expiration: Over 3 Years
Standby letters of credit [1]	**$ 122.4**	$ 24.7	$ —	$ 97.7
Surety bonds [2]	**33.6**	33.6	—	—
Other guarantees [3]	**11.6**	—	—	11.6
Total guarantees	**$ 167.6**	$ 58.3	$ —	$ 109.3

(1) At our request or the request of our subsidiaries, financial institutions have issued standby letters of credit for the benefit of third parties that have extended credit to our subsidiaries. These amounts are not reflected on our balance sheets.

(2) Primarily for environmental remediation, workers compensation self-insurance programs, and obtaining various licenses, permits, and rights-of-way. These amounts are not reflected on our balance sheets.

(3) Related to workers compensation coverage for which a liability was recorded on our balance sheets.

NOTE 20—EMPLOYEE BENEFITS

Pension and Other Postretirement Employee Benefits

We and our subsidiaries have defined benefit pension plans that cover substantially all of our employees, as well as several unfunded non-qualified retirement plans. In addition, we and our subsidiaries offer multiple OPEB plans to employees. The benefits for a portion of these plans are funded through irrevocable trusts, as allowed for income tax purposes. We also offer medical, dental, and life insurance benefits to active employees and their dependents. We expense the costs of these benefits as incurred.

Generally, former Wisconsin Energy Corporation employees who started with the company after 1995 receive a benefit based on a percentage of their annual salary plus an interest credit, while employees who started before 1996 receive a benefit based upon years of service and final average salary. Wisconsin Energy Corporation management employees hired after December 31, 2014, and certain new represented employees hired after May 1, 2017, receive an annual company contribution to their 401(k) savings plan instead of being enrolled in the defined benefit plans.

For former Integrys employees, the defined benefit pension plans are closed to all new hires. In addition, the service accruals for the defined benefit pension plans were frozen for non-union employees as of January 1, 2013. These employees receive an annual company contribution to their 401(k) savings plan, which is calculated based on age, wages, and full years of vesting service as of December 31 each year.

We use a year-end measurement date to measure the funded status of all of our pension and OPEB plans. Due to the regulated nature of our business, we have concluded that substantially all of the unrecognized costs resulting from the recognition of the funded status of our pension and OPEB plans qualify as a regulatory asset.

The following tables provide a reconciliation of the changes in our plans' benefit obligations and fair value of assets:

	Pension Benefits		OPEB Benefits	
(in millions)	**2023**	**2022**	**2023**	**2022**
Change in benefit obligation				
Obligation at January 1	**$ 2,315.9**	$ 3,136.6	**$ 402.3**	$ 530.2
Service cost	**24.0**	50.8	**9.8**	14.3
Interest cost	**122.3**	91.8	**21.6**	15.4
Participant contributions	**—**	—	**11.8**	12.5
Plan amendments	**—**	—	**—**	0.2
Actuarial (gain) loss	**81.9**	(682.3)	**45.9**	(127.9)
Benefit payments	**(191.7)**	(281.0)	**(46.0)**	(45.7)
Federal subsidy on benefits paid	**N/A**	N/A	**1.5**	1.4
Transfer	**—**	—	**1.2**	1.9
Obligation at December 31	**$ 2,352.4**	$ 2,315.9	**$ 448.1**	$ 402.3
Change in fair value of plan assets				
Fair value at January 1	**$ 2,628.0**	$ 3,328.9	**$ 835.3**	$ 1,000.2
Actual return on plan assets	**214.9**	(431.3)	**76.4**	(135.4)
Employer contributions net of plan transfer [(1)]	**14.6**	11.4	**(47.9)**	3.7
Participant contributions	**—**	—	**11.8**	12.5
Benefit payments	**(191.7)**	(281.0)	**(46.0)**	(45.7)
Fair value at December 31	**$ 2,665.8**	$ 2,628.0	**$ 829.6**	$ 835.3
Funded status at December 31	**$ 313.4**	$ 312.1	**$ 381.5**	$ 433.0

[(1)] Employer contribution includes a $50.0 million transfer out of the WEC Energy Group Retiree Welfare Plan, in 2023, associated with the overfunded position of this plan.

In 2023, we had actuarial losses related to our pension benefit obligations of $81.9 million and actuarial gains in 2022 of $682.3 million. The primary driver for the actuarial loss was a lower discount rate in 2023. Partially offsetting the loss in 2023, was higher than expected asset returns. The discount rate for our pension benefits was 5.19%, 5.49%, and 2.96% in 2023, 2022, and 2021, respectively.

In 2023, we had actuarial losses related to our OPEB benefit obligation of $45.9 million and actuarial gains in 2022 of $127.9 million. The primary driver for the actuarial loss was changes to medical trend assumptions and a lower discount rate in 2023. Partially offsetting the loss in 2023, was higher than expected asset returns. The discount rate for our OPEB benefits was 5.16%, 5.50%, and 2.92% in 2023, 2022, and 2021, respectively.

The amounts recognized on our balance sheets at December 31 related to the funded status of the benefit plans were as follows:

	Pension Benefits		OPEB Benefits	
(in millions)	**2023**	**2022**	**2023**	**2022**
Pension and OPEB assets	**$ 475.2**	$ 470.6	**$ 395.7**	$ 446.1
Pension and OPEB obligations	**161.8**	158.5	**14.2**	13.1
Total net assets	**$ 313.4**	$ 312.1	**$ 381.5**	$ 433.0

The accumulated benefit obligation for all defined benefit pension plans was $2,279.6 million and $2,250.6 million as of December 31, 2023 and 2022, respectively.

The following table shows information for pension plans with an accumulated benefit obligation in excess of plan assets. Amounts presented are as of December 31:

(in millions)	**2023**	**2022**
Accumulated benefit obligation	**$ 300.7**	$ 185.7
Fair value of plan assets	**147.3**	32.8

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The following table shows information for pension plans with a projected benefit obligation in excess of plan assets. Amounts presented are as of December 31:

(in millions)	2023	2022
Projected benefit obligation	**$ 306.7**	$ 191.3
Fair value of plan assets	**147.3**	32.8

The following table shows information for OPEB plans with an accumulated benefit obligation in excess of plan assets. Amounts presented are as of December 31:

(in millions)	2023	2022
Accumulated benefit obligation	**$ 21.0**	$ 20.6
Fair value of plan assets	**6.9**	7.4

The following table shows the amounts that had not yet been recognized in our net periodic benefit cost (credit) as of December 31:

	Pension Benefits		OPEB Benefits	
(in millions)	**2023**	**2022**	**2023**	**2022**
Pre-tax accumulated other comprehensive income (loss) [1]				
Net actuarial loss (gain)	**$ 12.7**	$ 12.2	**$ (1.2)**	$ (1.6)
Prior service credits	**—**	—	**—**	—
Total	**$ 12.7**	$ 12.2	**$ (1.2)**	$ (1.6)
Net regulatory assets (liabilities) [2]				
Net actuarial loss (gain)	**$ 688.9**	$ 669.2	**$ (166.3)**	$ (200.8)
Prior service credits	**(2.2)**	(2.1)	**(29.3)**	(44.2)
Total	**$ 686.7**	$ 667.1	**$ (195.6)**	$ (245.0)

[1] Amounts related to the nonregulated entities are included in accumulated other comprehensive loss.

[2] Amounts related to the utilities and WBS are recorded as net regulatory assets or liabilities.

The components of net periodic benefit cost (credit) (including amounts capitalized to our balance sheets) for the years ended December 31 were as follows:

	Pension Benefits			OPEB Benefits		
(in millions)	**2023**	**2022**	**2021**	**2023**	**2022**	**2021**
Service cost	**$ 24.0**	$ 50.8	$ 54.3	**$ 9.8**	$ 14.3	$ 15.7
Interest cost	**122.3**	91.8	87.5	**21.6**	15.4	14.5
Expected return on plan assets	**(187.4)**	(208.0)	(200.9)	**(53.0)**	(68.9)	(66.0)
Plan settlement	**1.3**	6.2	3.9	**—**	—	—
Plan curtailment	**—**	—	—	**—**	—	(6.4)
Amortization of prior service cost (credit)	**—**	1.6	1.6	**(14.8)**	(15.9)	(15.9)
Amortization of net actuarial loss (gain)	**33.0**	75.3	109.4	**(12.3)**	(24.7)	(24.4)
Net periodic benefit cost (credit)	**$ (6.8)**	$ 17.7	$ 55.8	**$ (48.7)**	$ (79.8)	$ (82.5)

Effective January 1, 2023, the PSCW approved escrow accounting for pension and OPEB costs. As a result, as of December 31, 2023, we recorded a $6.0 million regulatory asset for pension costs and a $14.8 million regulatory asset for OPEB costs. The above table does not reflect any adjustments for the creation of these regulatory assets.

The weighted-average assumptions used to determine the benefit obligations for the plans were as follows for the years ended December 31:

	Pension Benefits		OPEB Benefits	
	2023	**2022**	**2023**	**2022**
Discount rate	**5.19%**	5.49%	**5.16%**	5.50%
Rate of compensation increase	**4.00%**	4.00%	**N/A**	N/A
Interest credit rate	**4.84%**	4.61%	**N/A**	N/A
Assumed medical cost trend rate (Pre 65)	**N/A**	N/A	**6.25%**	6.50%
Ultimate trend rate (Pre 65)	**N/A**	N/A	**5.00%**	5.00%
Year ultimate trend rate is reached (Pre 65)	**N/A**	N/A	**2031**	2031
Assumed medical cost trend rate (Post 65)	**N/A**	N/A	**6.39%**	6.00%
Ultimate trend rate (Post 65)	**N/A**	N/A	**5.00%**	5.00%
Year ultimate trend rate is reached (Post 65)	**N/A**	N/A	**2030**	2031

The weighted-average assumptions used to determine the net periodic benefit cost for the plans were as follows for the years ended December 31:

	Pension Benefits		
	2023	**2022**	**2021**
Discount rate	**5.49%**	3.18%	2.71%
Expected return on plan assets	**6.62%**	6.88%	6.88%
Rate of compensation increase	**4.00%**	4.00%	4.00%
Interest credit rate	**4.62%**	3.78%	3.71%

	OPEB Benefits		
	2023	**2022**	**2021**
Discount rate	**5.50%**	2.92%	2.66%
Expected return on plan assets	**6.50%**	7.00%	7.00%
Assumed medical cost trend rate (Pre 65)	**6.50%**	5.70%	5.85%
Ultimate trend rate (Pre 65)	**5.00%**	5.00%	5.00%
Year ultimate trend rate is reached (Pre 65)	**2031**	2028	2028
Assumed medical cost trend rate (Post 65)	**6.00%**	5.67%	5.80%
Ultimate trend rate (Post 65)	**5.00%**	5.00%	5.00%
Year ultimate trend rate is reached (Post 65)	**2031**	2028	2028

We consult with our investment advisors on an annual basis to help us forecast expected long-term returns on plan assets by reviewing historical returns as well as calculating expected total trust returns using the weighted-average of long-term market returns for each of the major target asset categories utilized in the trust. For 2024, the expected return on assets assumption is 6.62% for the pension plans and 6.50% for the OPEB plans.

Plan Assets

Current pension trust assets and amounts which are expected to be contributed to the trusts in the future are expected to be adequate to meet pension payment obligations to current and future retirees.

The Investment Trust Policy Committee oversees investment matters related to all of our funded benefit plans. The Committee works with external actuaries and investment consultants on an on-going basis to establish and monitor investment strategies and target asset allocations. Forecasted cash flows for plan liabilities are regularly updated based on annual valuation results. Target allocations are determined utilizing projected benefit payment cash flows and risk analyses of appropriate investments. They are intended to reduce risk, provide long-term financial stability for the plans and maintain funded levels which meet long-term plan obligations while preserving sufficient liquidity for near-term benefit payments.

The legacy Wisconsin Energy Corporation pension trust target asset allocations are 25% equity investments, 55% fixed income investments, and 20% private equity and real estate investments. The legacy Integrys pension trust target asset allocations are 25% equity investments, 55% fixed income investments, and 20% private equity and real estate investments. The legacy Wisconsin

Energy Corporation OPEB trust target asset allocations are 45% equity investments, 45% fixed income investments, and 10% real estate investments. The two largest legacy OPEB trusts for Integrys have the same target asset allocations of 45% equity investments, 45% fixed income investments, and 10% real estate investments. Equity securities include investments in large-cap, mid-cap, and small-cap companies. Fixed income securities include corporate bonds of companies from diversified industries, mortgage and other asset backed securities, commercial paper, and United States Treasuries.

Pension and OPEB plan investments are recorded at fair value. See Note 1(r), Fair Value Measurements, for more information regarding the fair value hierarchy and the classification of fair value measurements based on the types of inputs used.

The following tables provide the fair values of our investments by asset class:

	December 31, 2023							
	Pension Plan Assets				OPEB Assets			
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Asset Class								
Equity securities:								
United States equity	**$ 179.3**	**$ —**	**$ —**	**$ 179.3**	**$ 91.8**	**$ —**	**$ —**	**$ 91.8**
International equity	**174.0**	**—**	**—**	**174.0**	**84.6**	**—**	**—**	**84.6**
Fixed income securities: [1]								
United States bonds	**—**	**906.6**	**—**	**906.6**	**91.5**	**203.2**	**—**	**294.7**
International bonds	**—**	**88.0**	**—**	**88.0**	**—**	**11.9**	**—**	**11.9**
	353.3	**994.6**	**—**	**1,347.9**	**267.9**	**215.1**	**—**	**483.0**
Investments measured at net asset value:								
Equity securities				**407.4**				**182.1**
Fixed income securities				**124.2**				**47.7**
Other				**786.3**				**116.8**
Total				**$2,665.8**				**$ 829.6**

[1] This category represents investment grade bonds of United States and foreign issuers denominated in United States dollars from diverse industries.

	December 31, 2022							
	Pension Plan Assets				OPEB Assets			
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Asset Class								
Equity securities:								
United States equity	$ 231.5	$ —	$ —	$ 231.5	$ 92.5	$ —	$ —	$ 92.5
International equity	202.2	—	—	202.2	83.9	—	—	83.9
Fixed income securities: [1]								
United States bonds	—	838.7	—	838.7	129.8	145.3	—	275.1
International bonds	—	95.0	—	95.0	—	13.2	—	13.2
	433.7	933.7	—	1,367.4	306.2	158.5	—	464.7
Investments measured at net asset value:								
Equity securities				466.0				186.6
Fixed income securities				101.0				65.5
Other				693.6				118.5
Total				$2,628.0				$ 835.3

[1] This category represents investment grade bonds of United States and foreign issuers denominated in United States dollars from diverse industries.

Cash Flows

We expect to contribute $13.1 million to the pension plans and $2.2 million to the OPEB plans in 2024, dependent upon various factors affecting us, including our liquidity position and possible tax law changes.

The following table shows the payments, reflecting expected future service, that we expect to make for pension and OPEB over the next 10 years:

(in millions)	Pension Benefits	OPEB Benefits
2024	$ 207.0	$ 34.3
2025	199.6	34.4
2026	202.2	34.9
2027	193.9	35.4
2028	188.8	35.5
2029-2033	847.4	175.3

Savings Plans

We sponsor 401(k) savings plans which allow employees to contribute a portion of their pre-tax and/or after-tax income in accordance with plan-specified guidelines. A percentage of employee contributions are matched by us through a contribution into the employee's savings plan account, up to certain limits. The 401(k) savings plans include an Employee Stock Ownership Plan. Certain employees receive an employer retirement contribution, in which amounts are contributed to the employee's savings plan account based on the employee's wages, age, and years of service. Total costs incurred under all of these plans were $57.5 million, $54.4 million, and $51.8 million in 2023, 2022, and 2021, respectively.

NOTE 21—INVESTMENT IN TRANSMISSION AFFILIATES

We own approximately 60% of ATC, a for-profit, transmission-only company regulated by the FERC for cost of service and certain state regulatory commissions for routing and siting of transmission projects. We also own approximately 75% of ATC Holdco, a separate entity formed in December 2016 to invest in transmission-related projects outside of ATC's traditional footprint. ATC's corporate manager has a ten-member board of directors, and ATC Holdco's corporate manager has a four-member board of directors. We have one representative on each board. Each member of the board has only one vote. The following tables provide a reconciliation of the changes in our investments in ATC and ATC Holdco:

	2023		
(in millions)	**ATC**	**ATC Holdco**	**Total**
Balance at January 1	**$ 1,884.6**	**$ 24.6**	**$ 1,909.2**
Add: Earnings from equity method investment	**175.1**	**2.4**	**177.5**
Add: Capital contributions	**63.7**	**—**	**63.7**
Less: Distributions	**142.6**	**1.9**	**144.5**
Balance at December 31	**$ 1,980.8**	**$ 25.1**	**$ 2,005.9**

	2022		
(in millions)	**ATC**	**ATC Holdco**	**Total**
Balance at January 1	$ 1,766.9	$ 22.5	$ 1,789.4
Add: Earnings from equity method investment	192.6	2.1	194.7
Add: Capital contributions	45.5	—	45.5
Less: Distributions	120.4	—	120.4
Balance at December 31	$ 1,884.6	$ 24.6	$ 1,909.2

	2021		
(in millions)	**ATC**	**ATC Holdco**	**Total**
Balance at January 1	$ 1,733.5	$ 30.8	$ 1,764.3
Add: Earnings (loss) from equity method investment	166.4	(8.3)	158.1
Less: Distributions	133.0	—	133.0
Balance at December 31	$ 1,766.9	$ 22.5	$ 1,789.4

In November 2019 and May 2020, the FERC issued orders that addressed complaints related to ATC's allowed ROE. Due to the various petitions related to the complaint filed in February 2015, our financials at December 31, 2021 and 2020, included a $39.1 million liability for potential future refunds that ATC may have been required to provide. In August 2022, a decision issued by the D.C. Circuit Court of Appeals affirmed the FERC's previous orders related to the February 2015 complaint. Therefore, during the third quarter of 2022, we reversed the liability that was previously recorded, which increased our equity earnings from ATC.

We pay ATC for network transmission and other related services it provides. In addition, we provide a variety of operational, maintenance, and project management work for ATC, which is reimbursed by ATC. We are also required to initially fund the construction of transmission infrastructure upgrades needed for new generation projects. ATC owns these transmission assets and reimburses us for these costs when the new generation is placed in service.

The following table summarizes our significant related party transactions with ATC during the years ended December 31:

(in millions)	2023	2022	2021
Charges to ATC for services and construction	**$ 17.4**	$ 18.9	$ 22.9
Charges from ATC for network transmission services	**377.5**	363.7	361.0
Net refund (payment) from (to) ATC related to FERC ROE orders	**—**	(0.1)	7.3

As of December 31, 2023 and 2022, our balance sheets included the following receivables and payables for services provided to or received from ATC:

(in millions)	2023	2022
Accounts receivable for services provided to ATC	**$ 1.6**	$ 1.2
Accounts payable for services received from ATC	**49.9**	30.4
Amounts due from ATC for transmission infrastructure upgrades [1]	**46.1**	26.6

[1] The transmission infrastructure upgrades were primarily related to the construction of WE's and WPS's renewable energy projects.

Summarized financial data for ATC is included in the tables below:

	Year Ended December 31		
(in millions)	2023	2022	2021
Income statement data			
Operating revenues	**$ 818.9**	$ 751.2	$ 754.8
Operating expenses	**407.6**	381.5	376.2
Other expense, net	**131.7**	123.0	113.9
Net income	**$ 279.6**	$ 246.7	$ 264.7

(in millions)	December 31, 2023	December 31, 2022
Balance sheet data		
Current assets	**$ 115.2**	$ 89.6
Noncurrent assets	**6,337.0**	5,997.8
Total assets	**$ 6,452.2**	$ 6,087.4
Current liabilities	**$ 495.9**	$ 511.9
Long-term debt	**2,736.0**	2,613.0
Other noncurrent liabilities	**585.2**	485.8
Members' equity	**2,635.1**	2,476.7
Total liabilities and members' equity	**$ 6,452.2**	$ 6,087.4

NOTE 22—SEGMENT INFORMATION

We use net income attributed to common shareholders to measure segment profitability and to allocate resources to our businesses. At December 31, 2023, we reported six segments, which are described below.

- The Wisconsin segment includes the electric and natural gas utility operations of WE, WPS, WG, and UMERC.

- The Illinois segment includes the natural gas utility operations of PGL and NSG.

- The other states segment includes the natural gas utility operations of MERC and MGU and the non-utility operations of MERC.

- The electric transmission segment includes our approximate 60% ownership interest in ATC, a for-profit, transmission-only company regulated by the FERC for cost of service and certain state regulatory commissions for routing and siting of transmission projects, and our approximate 75% ownership interest in ATC Holdco, which was formed to invest in transmission-related projects outside of ATC's traditional footprint.

- The non-utility energy infrastructure segment includes:
  - We Power, which owns and leases generating facilities to WE,
  - Bluewater, which owns underground natural gas storage facilities in Michigan that provide approximately one-third of the current storage needs for our Wisconsin natural gas utilities, and
  - WECI, which owns majority interests in multiple renewable generating facilities.

  See Note 2, Acquisitions, for more information on recent WECI acquisitions.

- The corporate and other segment includes the operations of the WEC Energy Group holding company, the Integrys holding company, the PELLC holding company, Wispark, Wisvest, WECC, and WBS.

All of our operations and assets are located within the United States. The following tables show summarized financial information related to our reportable segments for the years ended December 31, 2023, 2022, and 2021.

2023 (in millions)	Utility Operations							
	Wisconsin	Illinois	Other States	Total Utility Operations	Electric Transmission	Non-Utility Energy Infrastructure	Corporate and Other	Recon Elimin
External revenues	**$ 6,625.9**	**$1,557.8**	**$ 519.1**	**$ 8,702.8**	**$ —**	**$ 190.1**	**$ 0.1**	**$**
Intersegment revenues	**—**	**—**	**—**	**—**	**—**	**476.4**	**—**	**(4**
Other operation and maintenance	**1,531.3**	**397.9**	**94.5**	**2,023.7**	**—**	**80.1**	**5.8**	
Impairment related to ICC disallowances	**—**	**178.9**	**—**	**178.9**	**—**	**—**	**—**	
Depreciation and amortization	**851.5**	**237.3**	**43.3**	**1,132.1**	**—**	**188.7**	**20.9**	**(**
Equity in earnings of transmission affiliates	**—**	**—**	**—**	**—**	**177.5**	**—**	**—**	
Interest expense	**601.0**	**88.9**	**15.9**	**705.8**	**19.4**	**94.3**	**257.6**	**(3**
Income tax expense (benefit)	**237.4**	**48.6**	**16.3**	**302.3**	**39.0**	**(68.4)**	**(68.3)**	
Net income (loss)	**852.5**	**140.0**	**48.1**	**1,040.6**	**119.1**	**334.8**	**(162.8)**	
Net income (loss) attributed to common shareholders	**851.3**	**140.0**	**48.1**	**1,039.4**	**119.1**	**336.0**	**(162.8)**	
Capital expenditures and asset acquisitions	**2,134.4**	**489.8**	**103.5**	**2,727.7**	**—**	**754.4**	**25.8**	
Total assets [1]	**28,527.3**	**7,970.2**	**1,571.5**	**38,069.0**	**2,006.0**	**6,404.7**	**1,100.1**	**(3,6**

[1] Total assets at December 31, 2023 reflect an elimination of $1,630.6 million for all lease activity between We Power and WE.

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2022 (in millions)	Utility Operations							
	Wisconsin	Illinois	Other States	Total Utility Operations	Electric Transmission	Non-Utility Energy Infrastructure	Corporate and Other	Reconci Eliminat
External revenues	$ 6,960.5	$1,890.9	$ 618.5	$ 9,469.9	$ —	$ 127.0	$ 0.5	$
Intersegment revenues	—	—	—	—	—	463.0	—	(46
Other operation and maintenance	1,351.3	459.2	98.5	1,909.0	—	51.0	(12.9)	(
Depreciation and amortization	754.7	230.9	40.9	1,026.5	—	139.2	25.0	(6
Equity in earnings of transmission affiliates	—	—	—	—	194.7	—	—	
Interest expense	555.9	73.8	13.9	643.6	19.4	68.9	119.4	(33
Income tax expense (benefit)	247.5	83.1	13.1	343.7	45.8	(20.9)	(45.7)	
Net income (loss)	759.6	226.9	39.7	1,026.2	129.5	324.8	(70.8)	
Net income (loss) attributed to common shareholders	758.4	226.9	39.7	1,025.0	129.5	324.4	(70.8)	
Capital expenditures and asset acquisitions	1,610.8	484.9	101.1	2,196.8	—	483.8	16.3	
Total assets [1]	27,384.0	8,101.0	1,639.6	37,124.6	1,909.4	5,320.6	774.0	(3,25

[1] Total assets at December 31, 2022 reflect an elimination of $1,632.9 million for all lease activity between We Power and WE.

2021 (in millions)	Utility Operations: Wisconsin	Illinois	Other States	Total Utility Operations	Electric Transmission	Non-Utility Energy Infrastructure	Corporate and Other	Recon Elimina
External revenues	$ 6,037.0	$1,672.8	$ 519.0	$ 8,228.8	$ —	$ 86.7	$ 0.5	$
Intersegment revenues	—	—	—	—	—	452.8	—	(
Other operation and maintenance	1,455.2	433.5	90.4	1,979.1	—	43.1	(7.5)	
Depreciation and amortization	726.9	218.1	38.1	983.1	—	125.3	25.9	
Equity in earnings of transmission affiliates	—	—	—	—	158.1	—	—	
Interest expense	555.6	66.6	6.2	628.4	19.4	71.0	92.8	(
Loss on debt extinguishment	—	—	—	—	—	—	36.3	
Income tax expense (benefit)	119.9	79.3	11.5	210.7	32.3	3.1	(45.8)	
Net income (loss)	707.7	223.0	35.8	966.5	106.3	276.2	(50.5)	
Net income (loss) attributed to common shareholders	706.5	223.0	35.8	965.3	106.3	279.2	(50.5)	
Capital expenditures and asset acquisitions	1,389.7	533.7	95.9	2,019.3	—	335.3	18.1	
Total assets [1]	25,687.9	7,853.4	1,506.1	35,047.4	1,792.7	4,627.7	785.3	(3,

[1] Total assets at December 31, 2021 reflect an elimination of $1,729.9 million for all lease activity between We Power and WE.

NOTE 23—VARIABLE INTEREST ENTITIES

The primary beneficiary of a VIE must consolidate the entity's assets and liabilities. In addition, certain disclosures are required for significant interest holders in VIEs.

We assess our relationships with potential VIEs, such as our coal suppliers, natural gas suppliers, coal transporters, natural gas transporters, and other counterparties related to PPAs, investments, and joint ventures. In making this assessment, we consider, along with other factors, the potential that our contracts or other arrangements provide subordinated financial support, the obligation to absorb the entity's losses, the right to receive residual returns of the entity, and the power to direct the activities that most significantly impact the entity's economic performance.

WEPCo Environmental Trust Finance I, LLC

In November 2020, the PSCW issued a financing order approving the securitization of $100 million of undepreciated environmental control costs related to WE's retired Pleasant Prairie power plant, the carrying costs accrued on the $100 million during the securitization process, and the related financing fees. The financing order also authorized WE to form WEPCo Environmental Trust, a bankruptcy-remote special purpose entity, for the sole purpose of issuing ETBs to recover the costs approved in the financing order. WEPCo Environmental Trust is a wholly owned subsidiary of WE.

In May 2021, WEPCo Environmental Trust issued ETBs and used the proceeds to acquire environmental control property from WE. The environmental control property is recorded as a regulatory asset on our balance sheets and includes the right to impose, collect, and receive a non-bypassable environmental control charge from WE's retail electric distribution customers until the ETBs are paid in full and all financing costs have been recovered. The ETBs are secured by the environmental control property. Cash collections from the environmental control charge and funds on deposit in trust accounts are the sole sources of funds to satisfy the debt obligation. The bondholders do not have any recourse to WE or any of WE's affiliates.

WE acts as the servicer of the environmental control property on behalf of WEPCo Environmental Trust and is responsible for metering, calculating, billing, and collecting the environmental control charge. As necessary, WE is authorized to implement periodic adjustments of the environmental control charge. The adjustments are designed to ensure the timely payment of principal, interest, and other ongoing financing costs. WE remits all collections of the environmental control charge to WEPCo Environmental Trust's indenture trustee.

WEPCo Environmental Trust is a VIE primarily because its equity capitalization is insufficient to support its operations. As described above, WE has the power to direct the activities that most significantly impact WEPCo Environmental Trust's economic performance. Therefore, WE is considered the primary beneficiary of WEPCo Environmental Trust, and consolidation is required.

The following table summarizes the impact of WEPCo Environmental Trust on our balance sheet:

(in millions)	December 31, 2023	December 31, 2022
Assets		
Other current assets (restricted cash)	**$ 0.8**	$ 3.0
Regulatory assets	**85.9**	92.4
Other long-term assets (restricted cash)	**0.6**	0.6
Liabilities		
Current portion of long-term debt	**9.0**	8.9
Other current liabilities (accrued interest)	**0.1**	0.1
Long-term debt	**85.3**	94.1

Investment in Transmission Affiliates

We own approximately 60% of ATC, a for-profit, electric transmission company regulated by the FERC and certain state regulatory commissions. We have determined that ATC is a VIE but consolidation is not required since we are not ATC's primary beneficiary. As a result of our limited voting rights, we do not have the power to direct the activities that most significantly impact ATC's economic performance. Therefore, we account for ATC as an equity method investment. At December 31, 2023 and 2022, our equity investment in ATC was $1,980.8 million and $1,884.6 million, respectively, which approximates our maximum exposure to loss as a result of our involvement with ATC.

We also own approximately 75% of ATC Holdco, a separate entity formed in December 2016 to invest in transmission-related projects outside of ATC's traditional footprint. We have determined that ATC Holdco is a VIE but consolidation is not required since we are not ATC Holdco's primary beneficiary. As a result of our limited voting rights, we do not have the power to direct the activities that most significantly impact ATC Holdco's economic performance. Therefore, we account for ATC Holdco as an equity method investment. At December 31, 2023 and 2022, our equity investment in ATC Holdco was $25.1 million and $24.6 million, respectively, which approximates our maximum exposure to loss as a result of our involvement with ATC Holdco.

See Note 21, Investment in Transmission Affiliates, for more information, including any significant assets and liabilities related to ATC and ATC Holdco recorded on our balance sheets.

Power Purchase Commitment

On May 31, 2022, WE's PPA with LSP-Whitewater Limited Partnership that represented a variable interest expired. This agreement was for 236.5 MWs of firm capacity from a natural gas-fired cogeneration facility, and we accounted for it as a finance lease.

In November 2021, WE entered into a tolling agreement with LSP-Whitewater Limited Partnership that commenced on June 1, 2022, upon the expiration of the PPA. Concurrent with the execution of the tolling agreement, WE and WPS also entered into an agreement to purchase the natural gas-fired cogeneration facility. This asset purchase agreement was approved by the PSCW in December 2022, and the acquisition closed effective January 1, 2023. See Note 2, Acquisitions, for more information on the acquisition of this facility. The tolling agreement represented a variable interest until the facility was acquired since its terms were substantially similar to the terms of the PPA. Based on the risks of the entity, including operations, maintenance, dispatch, financing, fuel costs, and other factors, we were not the primary beneficiary of the entity. We did not hold an equity or debt interest in the entity, and there was no residual guarantee associated with the tolling agreement. Similar to the PPA, we accounted for the tolling agreement as a finance lease.

NOTE 24—COMMITMENTS AND CONTINGENCIES

We and our subsidiaries have significant commitments and contingencies arising from our operations, including those related to unconditional purchase obligations, environmental matters, and enforcement and litigation matters.

Unconditional Purchase Obligations

Our electric utilities have obligations to distribute and sell electricity to their customers, and our natural gas utilities have obligations to distribute and sell natural gas to their customers. The utilities expect to recover costs related to these obligations in future customer rates. In order to meet these obligations, we routinely enter into long-term purchase and sale commitments for various quantities and lengths of time.

The generation facilities that are part of our non-utility energy infrastructure segment have obligations to distribute and sell electricity through long-term offtake agreements with their customers for all of the energy produced. In order to support these sales obligations, these companies enter into easements and other service agreements associated with the generating facilities.

The following table shows our minimum future commitments related to these purchase obligations as of December 31, 2023, including those of our subsidiaries:

			Payments Due By Period					
(in millions)	**Date Contracts Extend Through**	**Total Amounts Committed**	**2024**	**2025**	**2026**	**2027**	**2028**	**Later Years**
Electric utility:								
Nuclear	2033	$ 6,280.6	$ 600.3	$ 634.5	$ 681.6	$ 730.4	$ 782.6	$2,851.2
Coal supply and transportation	2026	549.0	358.3	164.6	26.1	—	—	—
Purchased power	2063	333.5	56.7	56.4	57.5	52.1	48.4	62.4
Other	2043	100.6	13.9	13.3	12.9	11.6	10.2	38.7
Natural gas utility:								
Supply and transportation	2048	1,777.2	381.2	274.9	214.8	197.4	155.7	553.2
Non-utility energy infrastructure:								
Purchased power	2050	611.8	34.4	34.8	35.9	36.7	34.8	435.2
Natural gas storage and transportation	2048	4.8	4.0	—	—	—	0.1	0.7
Total		$ 9,657.5	$1,448.8	$1,178.5	$1,028.8	$1,028.2	$1,031.8	$3,941.4

Environmental Matters

Consistent with other companies in the energy industry, we face significant ongoing environmental compliance and remediation obligations related to current and past operations. Specific environmental issues affecting us include, but are not limited to, current and future regulation of air emissions such as SO_2, NOx, fine particulates, mercury, and GHGs; water intake and discharges; management of coal combustion products such as fly ash; and remediation of impacted properties, including former manufactured gas plant sites.

We have continued to pursue a proactive strategy to manage our environmental compliance obligations, including:

- the development of additional sources of renewable electric energy supply, battery storage, and natural gas and LNG storage facilities;
- the addition of improvements for water quality matters such as treatment technologies to meet regulatory discharge limits and improvements to our cooling water intake systems;

- the addition of emission control equipment to existing facilities to comply with ambient air quality standards and federal clean air rules;
- the protection of wetlands and waterways, biodiversity including threatened and endangered species, and cultural resources associated with construction projects;
- the retirement of older coal-fired power plants and conversion to modern, efficient, natural gas generation, super-critical pulverized coal generation, and/or replacement with renewable generation;
- the beneficial use of ash and other products from coal-fired and biomass generating units;
- the remediation of former manufactured gas plant sites;
- the reduction of methane emissions across our natural gas distribution system by upgrading infrastructure; and
- the reporting of GHG emissions to comply with federal clean air rules.

Air Quality

Cross State Air Pollution Rule – Good Neighbor Plan

In March 2023, the EPA issued its final Good Neighbor Plan, which became effective in August 2023 and requires significant reductions in ozone-forming emissions of NOx from power plants and industrial facilities. After review of the final rule, we believe that we are well positioned to meet the requirements.

Our RICE units in the Upper Peninsula of Michigan and Wisconsin are not currently subject to the final rule as each unit is less than 25 MWs. To the extent we use RICE engines for natural gas distribution operations, those engines not part of an LDC are subject to the emission limits and operational requirements of the rule beginning in 2026. The EPA has exempted LDCs from the final rule.

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Mercury and Air Toxics Standards

In 2012, the EPA issued the MATS to limit emissions of mercury, acid gases, and other hazardous air pollutants. In April 2023, the EPA issued the pre-publication version of a proposed rule to strengthen and update MATS to reflect recent developments in control technologies and performance of coal and oil-fired units. The EPA proposed three revisions including a proposal to lower the PM limit from 0.03 lb/MMBtu to 0.01 lb/MMBtu. The EPA also sought comments on an even lower limit of 0.006 lb/MMBtu. Adoption of either of these lower limits could have an adverse effect on our operations.

National Ambient Air Quality Standards

Ozone

After completing its review of the 2008 ozone standard, the EPA released a final rule in October 2015, creating a more stringent standard than the 2008 NAAQS. The 2015 ozone standard lowered the 8-hour limit for ground-level ozone. In November 2022, the EPA's 2022 CASAC Ozone Review Panel issued a draft report supporting the reconsideration of the 2015 standard. The EPA staff initially issued a draft Policy Assessment in March 2023 that supported the reconsideration, however, in August 2023 it announced that it is instead restarting its ozone standard evaluation. The EPA has indicated it plans to release its Integrated Review Plan in fall 2024. This new review is anticipated to take 3 to 5 years to complete.

In February 2022, revisions to the Wisconsin Administrative Code to adopt the 2015 standard were finalized. The amended regulations incorporated by reference the federal air pollution monitoring requirements related to the standard. The WDNR submitted the rule updates as a SIP revision to the EPA, which the EPA approved in February 2023.

In April 2022, the EPA proposed to find that the Milwaukee, Sheboygan, and Chicago, IL-IN-WI nonattainment areas did not meet the marginal attainment deadline of August 2021 and should be adjusted to "moderate" nonattainment status for the 2015 standard. In October 2022, the EPA published its final reclassifications from "marginal" to "moderate" for these areas, effective November 7, 2022. Accordingly, the WDNR submitted a SIP revision to the EPA in December 2022 to address the moderate nonattainment status.

In October 2023, the EPA found that 11 states, including Wisconsin, failed to submit timely SIP revisions to address nonattainment areas classified as "moderate" for the 2015 standard. This action triggered a 24-month deadline for states to get their SIP approved or the EPA will issue a federal implementation plan. Additionally, offset sanctions will take effect in 18 months if the SIP is not approved. The offset sanctions impact volatile organic compound and NOx emissions from new or modified sources in the nonattainment areas.

We believe that we are well positioned to meet the requirements associated with the 2015 ozone standard and do not expect to incur significant costs to comply with the associated state and federal rules.

Particulate Matter

In December 2020, the EPA completed its 5-year review of the 2012 annual and 24-hour standards for fine PM and determined that no revisions were necessary to the current annual standard of 12 $\mu g/m^3$ or the 24-hour standard of 35 $\mu g/m^3$. All counties within our service territories are in attainment with the current 2012 standards. Under the Biden Administration's policy review, the EPA concluded that the scientific evidence and information from the December 2020 determination supports revising the level of the annual standard for the PM NAAQS to below the current level of 12 $\mu g/m^3$, while retaining the 24-hour standard. In January 2023, the EPA announced its proposed decision to revise the primary (health-based) annual PM2.5 standard from its current level of 12 $\mu g/m^3$ to within the range of 9 to 10 $\mu g/m^3$. The EPA also proposed not to change the current secondary (welfare-based) annual PM2.5 standard, primary and secondary 24-hour PM2.5 standards, and primary and secondary PM10 standards. The EPA did, however, take comments on the full range (between 8 and 11 $\mu g/m^3$) included in the CASAC's latest report. The EPA finalized the rule on February 7, 2024 and lowered the primary annual PM2.5 level to 9 $\mu g/m^3$, which could cause some nonattainment areas that may affect permitting at our facilities. The secondary and 24-hour standards remain unchanged. The EPA will designate areas as attainment and nonattainment with the new standard by early 2026. The WDNR will need to draft and submit a SIP for the EPA's approval.

Climate Change

In May 2023, the EPA proposed GHG performance standards for existing fossil-fired steam generating and gas combustion units and also proposed to repeal the Affordable Clean Energy rule, which had replaced the Clean Power Plan. For coal plants, no standards would apply under the proposed version of the rule until 2032, and after 2032 the applicable standard would depend on the unit's retirement date. For combined cycle natural gas plants above a 50% capacity factor, the proposed rule is highly dependent on the use of hydrogen as an alternative fuel, and on carbon capture technology. For simple cycle natural gas-fired combustion turbines, the proposed version of the rule does not include applicable limits as long as the capacity factor is less than 20%. Our RICE units in Michigan and the new Weston RICE project are not affected under the rule because each RICE unit is less than 25 MWs. We continue to evaluate the proposed rule to understand the impacts to our operations. A final rule is expected in the second quarter of 2024.

In May 2023, the EPA proposed to revise the NSPS for GHG emissions from new, modified, and reconstructed fossil-fueled power plants. The EPA is proposing two distinct 111(b) rules – one for natural gas-fired stationary combustion turbines and the other for coal-fired units. New stationary combustion turbine units would be divided into three subcategories based on their annual capacity factor – low load, intermediate load, and base load. Our RICE units are not affected by this rule since each unit is below 25 MWs. Our ESG Progress Plan is heavily focused on reducing GHG emissions. The EPA has indicated that it anticipates a final rule in the second quarter of 2024.

The EPA released proposed regulations for the Mandatory Greenhouse Gas Reporting Rule, 40 CFR Part 98, in June 2022. In May 2023, the EPA released a supplementary proposal, which includes updates of the global warming potentials to determine CO_2 equivalency for threshold reporting and the addition of a new section regarding energy consumption. The proposed revisions could impact the reporting required for our electric generation facilities, local natural gas distribution companies, and underground natural gas storage facilities. In August 2023, the EPA also issued its proposed updates to amend reporting requirements for petroleum and natural gas systems, with an anticipated final rule to be issued in early 2024. We are currently evaluating the potential impact of the proposed rule, if any, on our operations.

Our ESG Progress Plan includes the retirement of older, fossil-fueled generation, to be replaced with zero-carbon-emitting renewables and clean natural gas-fueled generation. We have already retired more than 1,900 MWs of fossil-fueled generation since the beginning of 2018. We expect to retire approximately 1,800 MWs of additional fossil-fueled generation by the end of 2031, which includes the planned retirements in 2024-2025 of OCPP Units 5-8, the planned retirement by June 2026 of jointly-owned Columbia Units 1 and 2, and the planned retirement in 2031 of Weston Unit 3. See Note 7, Property, Plant, and Equipment, for more information related to these planned power plant retirements. In May 2021, we announced goals to achieve reductions in carbon emissions from our electric generation fleet by 60% by the end of 2025 and by 80% by the end of 2030, both from a 2005 baseline. We expect to achieve these goals by continuing to make operating refinements, retiring less efficient generating units, and executing our capital plan. Over the longer term, the target for our generation fleet is to be net carbon neutral by 2050.

We also continue to reduce methane emissions by improving our natural gas distribution systems, and have set a target across our natural gas distribution operations to achieve net-zero methane emissions by the end of 2030. We plan to achieve our net-zero goal through an effort that includes both continuous operational improvements and equipment upgrades, as well as the use of RNG throughout our utility systems.

Water Quality

Clean Water Act Cooling Water Intake Structure Rule

The EPA issued a final regulation under Section 316(b) of the CWA that became effective in October 2014 and requires the location, design, construction, and capacity of cooling water intake structures at existing power plants reflect the BTA for minimizing adverse environmental impacts. The rule applies to all of our existing generating facilities with cooling water intake structures, except for the ERGS units, which were permitted and received a final BTA determination under the rules governing new facilities.

Pursuant to a WDNR rule, which became effective in June 2020, the requirements of federal Section 316(b) of the CWA were incorporated into the Wisconsin Administrative Code. The WDNR applies this rule when establishing BTA requirements for cooling water intake structures at existing facilities. These BTA requirements are incorporated into WPDES permits for WE and WPS facilities.

We have received a final BTA determination for VAPP. We have received interim BTA determinations for OCPP Units 5-8 and Weston Units 3 and 4. We believe that existing technology installed at the OCPP facility meets the BTA requirements; however, depending on the timing of the permit reissuance, all four generating units at the OCPP may be retired prior to the WDNR making a final BTA decision, anticipated in 2025. In addition, we believe that existing technology installed at the Weston facility will result in a final BTA determination during the WPDES permit reissuance expected in the first quarter of 2024.

The WDNR reissued the WPDES permit for PWGS effective October 2023. This reissued permit includes a conditional BTA determination with conditions for the existing PWGS porous dike (rock breakwater) cooling water intake structure. We do not anticipate compliance with these conditions will result in a material impact on our financial condition or the efficiency of power plant operations.

Steam Electric Effluent Limitation Guidelines

The EPA's ELG rule, effective January 2016 and modified in 2020, revised the treatment technology requirements related to BATW and wet FGD wastewaters at existing coal-fueled facilities and created new requirements for several types of power plant wastewaters. The two new requirements that affect WE and WPS facilities relate to discharge limits for BATW and wet FGD wastewater. Although our power plant facilities already have advanced wastewater treatment technologies installed that meet many of the discharge limits established by this rule, certain facility modifications are necessary to meet the ELG rule requirements. Through 2023, compliance costs associated with the ELG rule required $105 million in capital investment. An $8 million BATW modification to OCPP Units 7 and 8 was completed and placed in-service in mid-2021, and in December 2021, the PSCW issued a Certificate of Authority approving the $89 million ERGS FGD wastewater treatment system modification. The BATW modifications, including $8 million of modifications at Weston Unit 3 completed in June 2023, did not require PSCW approval prior to construction. All of these ELG required projects were placed in-service ahead of WPDES permit deadlines.

In March 2023, the EPA issued the proposed "supplemental ELG rule." The rule would replace the existing 2020 ELG rule and, as proposed, would establish stricter limitations on: 1) BATW; 2) FGD wastewater; 3) CCR leachate; and 4) legacy wastewaters. The most significant proposed ELG rule change is a ZLD requirement for FGD wastewater. Under the proposed rule, this new ZLD requirement must be met by a date determined by the permitting authority (the WDNR for WE) that is as soon as possible beginning 60 days following publication of the final rule, but no later than December 31, 2029.

The proposed rule would also create a subcategory for "early adopters" that have already installed a compliant biological treatment system by the date of the proposed rule. Early adopters would not be required to install further FGD wastewater treatment, provided the facility owner also agrees to permanently cease combustion of coal by December 31, 2032. Although the $89 million biological treatment system at ERGS is complete and was placed in service in December 2023 to meet the WPDES permit deadline, the timing of the project's completion did not comply with the deadline proposed by the EPA to qualify for the early adopter status. In addition, we do not believe that the biological treatment system would be compliant with the additional ZLD FGD wastewater treatment requirements as proposed. In May 2023, we submitted written comments to the EPA articulating these concerns, including the cost impact to our customers. The EPA has indicated that it anticipates issuing the final rule in the second quarter of 2024.

If the supplemental ELG rule is finalized as proposed, we anticipate that our coal-fueled facilities, including ER 1 and ER 2 that were built with ELG-compliant dry BA transport systems, will meet the BATW rule provisions.

The EPA also proposed requirements for legacy wastewaters and landfill leachate. We have reviewed the proposed requirements to determine potential costs and actions required for our facilities. We submitted comments to the EPA regarding these proposed requirements.

Waters of the United States

In January 2023, the EPA and the Army Corps (the agencies) together released a final rule effective in March 2023 that established standards for identifying which wetland or surface drainage features qualify as WOTUS based on its pre-2015 definition. The pre-2015 approach involved applying factors established through case law and agency precedents to determine whether a wetland or surface drainage feature is subject to federal jurisdiction.

In May 2023, in Sackett v. EPA, the Supreme Court issued a decision significantly narrowing federal jurisdiction over wetlands to "traditional navigable waters" and wetlands or other waters that have a "continuous surface connection" with a traditional navigable water.

In August 2023, the agencies revised the final rule to conform the definition of WOTUS to the Supreme Court's May 2023 Sackett decision. The conforming rule became effective upon publication in the Federal Register on September 8, 2023.

We anticipate this final rule revision based on the Sackett decision may lead to a decreased number of projects that require Army Corps federal wetland permits. This decision also may affect the administration of some state programs. At this point, our projects requiring federal permits are moving ahead, but we are monitoring these recent developments to better understand potential future impacts.

Land Quality

Manufactured Gas Plant Remediation

We have identified sites at which our utilities or a predecessor company owned or operated a manufactured gas plant or stored manufactured gas. We have also identified other sites that may have been impacted by historical manufactured gas plant activities. Our natural gas utilities are responsible for the environmental remediation of these sites, some of which are in the EPA Superfund Alternative Approach Program. We are also working with various state jurisdictions in our investigation and remediation planning. These sites are at various stages of investigation, monitoring, remediation, and closure.

In addition, we are coordinating the investigation and cleanup of some of these sites subject to the jurisdiction of the EPA under what is called a "multisite" program. This program involves prioritizing the work to be done at the sites, preparation and approval of documents common to all of the sites, and use of a consistent approach in selecting remedies. At this time, we cannot estimate future remediation costs associated with these sites beyond those described below.

The future costs for detailed site investigation, future remediation, and monitoring are dependent upon several variables including, among other things, the extent of remediation, changes in technology, and changes in regulation. Historically, our regulators have allowed us to recover incurred costs, net of insurance recoveries and recoveries from potentially responsible parties, associated with the remediation of manufactured gas plant sites. Accordingly, we have established regulatory assets for costs associated with these sites.

We have established the following regulatory assets and reserves for manufactured gas plant sites as of December 31:

(in millions)	**2023**	**2022**
Regulatory assets	**$ 596.8**	$ 610.7
Reserves for future environmental remediation	**463.7**	499.6

Coal Combustion Residuals Rule

The EPA issued a pre-publication proposed rule for CCR in May 2023 that would apply to landfills, historic fill sites, and projects where CCR was placed at a power plant site. As proposed, the rule would regulate previously exempt closed landfills.

We are actively engaged with our trade organizations and provided them information to include in their comments to the EPA. The EPA has indicated that it anticipates issuing a final rule in the second quarter of 2024. As proposed, the rule could have a material adverse impact on our coal ash landfills and require additional remediation that has not been required under the current state programs.

Renewables, Efficiency, and Conservation

Wisconsin Legislation

In 2005, Wisconsin enacted Act 141, which established a goal that 10% of all electricity consumed in Wisconsin be generated by renewable resources annually. WE and WPS have achieved their required renewable energy percentages of 8.27% and 9.74%, respectively, by constructing various wind parks, solar parks, a biomass facility, and by also relying on renewable energy purchases. WE and WPS continue to review their renewable energy portfolios and acquire cost-effective renewables as needed to meet their requirements on an ongoing basis. The PSCW administers the renewable program related to Act 141, and each utility funds the program based on 1.2% of its annual retail operating revenues.

Michigan Legislation

In December 2016, Michigan enacted Act 342, which required 12.5% of the state's electric energy to come from renewables for 2019 and 2020, and energy optimization (efficiency) targets up to 1% annually. The renewable requirement increased to 15.0% for 2021 and beyond. UMERC was in compliance with its requirements under this statute as of December 31, 2023. The legislation continues to allow recovery of costs incurred to meet the standards and provides for ongoing review and revision to assure the measures taken are cost-effective.

In November 2023, Michigan enacted Acts 229, 231 and 235. The acts require electric providers to file a renewable energy plan every two years and to set renewable energy portfolio targets from now until 2040. The proposed renewable energy targets include 15% through 2029, 50% from 2030 through 2034, and 60% renewable energy by 2035 and thereafter. The bill also sets clean energy standards of 80% for 2035-2039 and 100% after 2040. The bill only allows natural gas to count as clean energy if it is accompanied with carbon capture and storage. The MPSC has indicated that it will complete a study by December 2024 on the unique conditions influencing electric generation, transmission, and demand in the Upper Peninsula of Michigan, which includes the unique role of RICE units placed in service to facilitate the retirement of coal-fired generation in the Upper Peninsula of Michigan. The new acts also revise the requirement a utility must meet in filing its energy waste reduction plans. They require a utility to file a plan every two years until 2025, then every three years thereafter.

Enforcement and Litigation Matters

We and our subsidiaries are involved in legal and administrative proceedings before various courts and agencies with respect to matters arising in the ordinary course of business. Although we are unable to predict the outcome of these matters, management believes that appropriate reserves have been established and that final settlement of these actions will not have a material impact on our financial condition or results of operations.

Consent Decrees

Wisconsin Public Service Corporation – Weston and Pulliam Power Plants

In November 2009, the EPA issued an NOV to WPS, which alleged violations of the CAA's New Source Review requirements relating to certain projects completed at the Weston and Pulliam power plants from 1994 to 2009. WPS entered into a Consent Decree with the EPA resolving this NOV. This Consent Decree was entered by the United States District Court for the Eastern District of Wisconsin in March 2013. With the retirement of Pulliam Units 7 and 8 in October 2018, WPS completed the mitigation projects required by the Consent Decree and received a completeness letter from the EPA in October 2018. See Note 6, Regulatory Assets and Liabilities, for more information about the retirement. We are working with the EPA on a closeout process for the Consent Decree and expect that process to begin in 2024.

Joint Ownership Power Plants – Columbia and Edgewater

In December 2009, the EPA issued an NOV to WPL, the operator of the Columbia and Edgewater plants, and the other joint owners of these plants, including MG&E, WE (former co-owner of an Edgewater unit), and WPS. The NOV alleged violations of the CAA's New Source Review requirements related to certain projects completed at those plants. WPS, along with WPL, MG&E, and WE, entered into a Consent Decree with the EPA resolving this NOV. This Consent Decree was entered by the United States District Court for the Western District of Wisconsin in June 2013. As a result of the continued implementation of the Consent Decree related to the jointly owned Columbia and Edgewater plants, the Edgewater

4 generating unit was retired in September 2018. See Note 6, Regulatory Assets and Liabilities, for more information about the retirement. WPL started the process to close out this Consent Decree.

NOTE 25—SUPPLEMENTAL CASH FLOW INFORMATION

Non-Cash Transactions

	Year Ended December 31		
(in millions)	**2023**	**2022**	**2021**
Cash paid for interest, net of amount capitalized	**$ 653.4**	$ 485.2	$ 473.8
Cash paid (received) for income taxes, net [1]	**(58.9)**	52.4	33.8
Significant non-cash investing and financing transactions:			
Accounts payable related to construction costs	**171.3**	197.4	127.8
Increase in receivables related to insurance proceeds	**3.5**	—	41.7
Liabilities accrued for software licensing agreement	**—**	7.4	—

[1] Cash received for income taxes in 2023 includes $75 million related to PTCs that were sold to a third party.

Restricted Cash

The statements of cash flows include our activity related to cash, cash equivalents, and restricted cash. The following table reconciles the cash, cash equivalents, and restricted cash amounts reported within the balance sheets at December 31 to the total of these amounts shown on the statements of cash flows:

(in millions)	**2023**	**2022**	**2021**
Cash and cash equivalents	**$ 42.9**	$ 28.9	$ 16.3
Restricted cash included in other current assets	**70.1**	25.6	19.6
Restricted cash included in other long-term assets	**52.2**	127.7	51.6
Cash, cash equivalents, and restricted cash	**$ 165.2**	$ 182.2	$ 87.5

Our restricted cash consisted of the following:

- Cash held in the Integrys rabbi trust, which is used to fund participants' benefits under the Integrys deferred compensation plan and certain Integrys non-qualified pension plans.
- Cash on deposit in financial institutions that is restricted to satisfy the requirements of certain debt agreements at WECI Wind Holding I, WECI Wind Holding II, and WEPCo Environmental Trust.
- Cash we received when WECI acquired ownership interests in certain renewable generation projects. This cash is restricted as it can only be used to pay for any remaining costs associated with the construction of the renewable generation facilities.

- Cash used by WE and WPS during January 2023 to purchase a natural gas-fired cogeneration facility located in Whitewater, Wisconsin. This cash was included in other long-term assets at December 31, 2022. See Note 2, Acquisitions, for more information on the purchase of this facility.

NOTE 26—REGULATORY ENVIRONMENT

Wisconsin Electric Power Company, Wisconsin Public Service Corporation, and Wisconsin Gas LLC

2024 Limited Rate Case Re-Opener

In accordance with their rate orders approved by the PSCW in December 2022, WE, WPS, and WG filed requests for limited electric and natural gas rate case re-openers, as applicable, with the PSCW in May 2023. The WE and WPS limited electric rate case re-openers included updated fuel costs and revenue requirements for the generation projects that were previously approved by the PSCW and were placed into service in 2023 or are expected to be placed into service in 2024. WE's limited electric re-opener also included the projected savings from the retirement of the OCPP Units 5 and 6, which are expected to be retired in May 2024. WE and WG also filed a request for a limited natural gas rate case re-opener to reflect the additional revenue requirements associated with their previously approved LNG projects. WE's LNG project was placed into service in November 2023, and WG's LNG project is expected to be placed into service in 2024.

On December 20, 2023, the PSCW issued final written orders approving electric and natural gas rate increases and decreases, effective January 1, 2024. The final orders reflected the following:

	WE	WPS	WG
2024 incremental rate increases (decreases)			
Electric [1]	$ 82.2 million / 2.5%	$ (32.7) million / (2.6) %	N/A
Gas	$ 23.9 million / 4.5%	N/A	$ 21.6 million / 2.8%

[1] Amounts reflect the impact to our Wisconsin retail electric operations and include any incremental increases (WE) or decreases (WPS) resulting from updated fuel costs.

The utilities' ROE and common equity component averages were not addressed in the limited rate case re-openers.

2023 and 2024 Rates

In April 2022, WE, WPS, and WG filed requests with the PSCW to increase their retail electric, natural gas, and steam rates, as applicable. These requests were updated in July 2022 to reflect new developments that impacted the original proposals. The requested increases in electric rates were driven by capital investments in new wind, solar, and battery storage; capital investments in natural gas generation; reliability investments, including grid hardening projects to bury power lines and strengthen WE's distribution system against severe weather; and changes in wholesale business with other utilities. Many of these investments had already been approved by the PSCW. The requested increases in natural gas rates primarily related to capital investments previously approved by the PSCW, including LNG storage for our natural gas distribution system.

In September 2022, WE, WPS, and WG entered into settlement agreements with certain intervenors to resolve most of the outstanding issues in each utility's respective rate case; however, the PSCW declined to approve the settlement agreements. In December 2022, the PSCW issued final written orders approving electric, natural gas, and steam base rate increases, effective January 1, 2023. The final orders reflected the following:

	WE	WPS	WG
2023 base rate increase			
Electric	$ 283.5 million / 9.1%	$ 120.5 million / 9.8%	N/A
Gas	$ 46.1 million / 9.6%	$ 26.4 million / 7.1%	$ 46.5 million / 6.4%
Steam	$ 7.6 million / 35.3%	N/A	N/A
ROE	9.8%	9.8%	9.8%
Common equity component average on a financial basis	53.0%	53.0%	53.0%

In addition to the above, the final orders included the following terms:

- The utilities will keep their current earnings sharing mechanisms, under which, if a utility earns above its authorized ROE: (i) the utility retains 100.0% of earnings for the first 15 basis points above the authorized ROE; (ii) 50.0% of the next 60 basis points is refunded to ratepayers; and (iii) 100.0% of any remaining excess earnings is required to be refunded to ratepayers.
- WE and WPS were required to complete an analysis of alternative recovery scenarios for generating units that will be retired prior to the end of their useful life.
- WE and WPS will not propose any changes to their real time pricing rates for large commercial and industrial electric customers through the end of 2024.
- WE and WPS were required to lower monthly residential and small commercial electric customer fixed charges by $1.00 and $3.33, respectively, from previously authorized rates.
- WE and WPS were required to offer an additional voluntary renewable energy pilot for commercial and industrial customers.
- WE and WPS will continue to work with PSCW staff and other interested parties to develop alternative low income assistance programs. WE and WPS also collectively contributed $4.0 million to the Keep Wisconsin Warm Fund.
- WE, WPS, and WG were required to implement escrow accounting treatment for pension and OPEB costs in 2023 and 2024.
- As discussed above, WE and WPS were authorized to file a limited electric rate case re-opener for 2024, and WE and WG were authorized to file a limited natural gas rate case re-opener for 2024.

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2022 Rates

In March 2021, WE, WPS, and WG filed an application with the PSCW for the approval of certain accounting treatments that allowed them to maintain their electric, natural gas, and steam base rates through 2022 and forego filing a rate case for one year. In connection with the request, the three utilities also entered into an agreement, dated March 23, 2021, with various stakeholders. Pursuant to the terms of the agreement, the stakeholders fully supported the application. In September 2021, the PSCW issued written orders approving the application.

The final orders reflected the following:

- WE, WPS, and WG amortized, in 2022, certain previously deferred balances to offset approximately half of their forecasted revenue deficiencies.
- WG deferred interest and depreciation expense associated with capital investments since its last rate case that otherwise would have been added to rate base in a 2022 test-year rate case.
- WE, WPS, and WG were able to defer any increases in tax expense due to changes in tax law that occurred in 2021 and/or 2022.
- WE, WPS, and WG maintained their earnings sharing mechanisms for 2022, with modification. The earnings sharing mechanisms were modified to authorize the utility to retain 100.0% of the first 15 basis points of earnings above its then authorized ROE. The earnings sharing mechanisms otherwise remained as previously authorized.

2020 and 2021 Rates

In March 2019, WE, WPS, and WG filed applications with the PSCW to increase their retail electric, natural gas, and steam rates, as applicable, effective January 1, 2020. In August 2019, all three utilities filed applications with the PSCW for approval of settlement agreements entered into with certain intervenors to resolve several outstanding issues in each utility's respective rate case. In December 2019, the PSCW issued written orders that approved the settlement agreements without material modification and addressed the remaining outstanding issues that were not included in the settlement agreements. The new rates were effective January 1, 2020. The final orders reflected the following:

	WE	WPS	WG
2020 Effective rate increase (decrease)			
Electric [1] [2]	$ 15.3 million / 0.5%	$ 15.8 million / 1.6%	N/A
Gas [3]	$ 10.4 million / 2.8%	$ 4.3 million / 1.4%	$ (1.5) million / (0.2)%
Steam	$ 1.9 million / 8.6%	N/A	N/A
ROE	10.0%	10.0%	10.2%
Common equity component average on a financial basis	52.5%	52.5%	52.5%

(1) Amounts are net of certain deferred tax benefits from the Tax Legislation that were utilized to reduce near-term rate impact. The WE and WPS rate orders reflected the majority of the unprotected

deferred tax benefits from the Tax Legislation being amortized over two years. For WE, approximately $65 million of tax benefits were amortized in each of 2020 and 2021. For WPS, approximately $11 million of tax benefits were amortized in 2020 and approximately $39 million were amortized in 2021. The unprotected deferred tax benefits related to the unrecovered balances of certain of WE's retired plants and its SSR regulatory asset were used to reduce the related regulatory asset. Unprotected deferred tax benefits by their nature are eligible to be returned to customers in a manner and timeline determined to be appropriate by our regulators.

(2) The WPS rate order was net of $21 million of refunds related to its 2018 earnings sharing mechanism. These refunds were made to customers evenly over two years, with half returned in 2020 and the remainder returned in 2021.

(3) The WE amount includes certain deferred tax expense from the Tax Legislation, and the WPS and WG amounts are net of certain deferred tax benefits from the Tax Legislation that were utilized to reduce near-term rate impact. The rate orders for all three gas utilities reflected all of the unprotected deferred tax expense and benefits from the Tax Legislation being amortized evenly over four years. For WE, approximately $5 million of previously deferred tax expense was amortized each year. For WPS and WG, approximately $5 million and $3 million, respectively, of previously deferred tax benefits was amortized each year. Unprotected deferred tax expense and benefits by their nature are eligible to be recovered from or returned to customers in a manner and timeline determined to be appropriate by our regulators.

In accordance with its rate order, WE filed an application with the PSCW in July 2020 requesting a financing order to securitize $100 million of Pleasant Prairie power plant's book value, plus the carrying costs accrued on the $100 million during the securitization process and the related financing fees. In November 2020, the PSCW issued a written order approving the application. The financing order also authorized WE to form a bankruptcy-remote special purpose entity, WEPCo Environmental Trust, for the sole purpose of issuing ETBs to recover the approved costs. In May 2021, WEPCo Environmental Trust issued $118.8 million of

1.578% ETBs due December 15, 2035. See Note 23, Variable Interest Entities, for more information regarding WEPCo Environmental Trust.

The WPS rate order allows WPS to collect the previously deferred revenue requirement for ReACT™ costs above the authorized $275 million level. The total cost of the ReACT™ project was $342 million. This regulatory asset is being collected from customers over eight years.

The PSCW approved all three Wisconsin utilities continuing to have an earnings sharing mechanism through 2021. The earnings sharing mechanism was modified from its previous structure to one that was consistent with other Wisconsin investor-owned utilities. Under this earnings sharing mechanism, if the utility earned above its authorized ROE: (i) the utility retained 100.0% of earnings for the first 25 basis points above the authorized ROE; (ii) 50.0% of the next 50 basis points were required to be refunded to customers; and (iii) 100.0% of any remaining excess earnings were required to be refunded to customers. In addition, the rate orders also required WE, WPS, and WG to maintain residential and small commercial electric and natural gas customer fixed charges at previously authorized rates and to maintain the status quo for WE's and WPS's electric market-based rate programs for large industrial customers through 2021.

The Peoples Gas Light and Coke Company and North Shore Gas Company

2023 Rate Order

On January 6, 2023, PGL and NSG filed requests with the ICC to increase their natural gas base rates. The requested rate increases were primarily driven by capital investments made to strengthen the safety and reliability of each utility’s natural gas distribution system. PGL was also seeking to recover costs incurred to upgrade its natural gas storage field and operations facilities and to continue improving customer service. PGL did not request an extension of the QIP rider as PGL will return to the traditional rate making process to recover the costs of necessary infrastructure improvements.

On November 16, 2023, the ICC issued final written orders approving base rate increases for PGL and NSG. The written orders were subsequently amended for various technical corrections. The amended written orders approved the following base rate increases:

- A $304.6 million (43.5%) base rate increase for PGL’s natural gas customers. This amount includes the recovery of costs related to PGL’s SMP that were previously being recovered under its QIP rider. PGL's new rates were effective December 1, 2023.
- An $11.0 million (11.6%) base rate increase for NSG’s natural gas customers. The new rates at NSG were not effective until February 1, 2024 as changes were required to NSG's billing system as a result of the final rate order.

The ICC approved an authorized ROE of 9.38% for both PGL and NSG, and set the common equity component average at 50.79% and 52.58% for PGL and NSG, respectively.

As part of its decisions, the ICC, among other things, disallowed $236.2 million of capital costs related to the construction and improvement of PGL’s shops and facilities and $1.7 million of capital costs related to NSG's construction of a gas infrastructure project. In addition, the ICC ordered PGL to pause spending on its SMP until the ICC has a proceeding to determine the optimal method for replacing aging natural gas infrastructure and a prudent investment level. In accordance with the written order, the ICC initiated the proceeding on January 31, 2024.

On December 15, 2023, PGL and NSG filed an application for rehearing with the ICC requesting reconsideration of various issues in the ICC's November 16, 2023 written orders. On January 3, 2024, the ICC granted PGL and NSG a limited-scope rehearing. The rehearing will be limited to:

- the authorized spending for the completion of SMP projects that started in 2023,
- the authorized spending for emergency repairs needed to ensure the safety and reliability of our delivery system, and
- the timing of changes required to NSG's billing system.

As the ICC did not grant a rehearing on the disallowance of PGL's and NSG's capital costs, we recorded a $178.9 million non-cash impairment of our property, plant, and equipment in 2023. This amount includes $177.2 million of previously incurred disallowed costs at PGL related to its shops and facilities, and the $1.7 million of capital costs disallowed at NSG. The remaining disallowance of capital costs at PGL related to expected future spend. We anticipate appealing the ICC’s disallowance of PGL's and NSG's capital costs to the Illinois circuit court after the rehearing process is complete.

An ICC decision on our limited-scope rehearing is expected in the second quarter of 2024.

Third-Party Transaction Fee Adjustment Rider

In accordance with the Climate and Equitable Jobs Act that was signed into law in Illinois, effective September 15, 2021, Illinois utilities are prohibited from charging customers a fee when they elect to pay for service with a credit card. Utilities are now required to incur these expenses and seek recovery through a rate proceeding or by establishing a recovery mechanism. In December 2021, the ICC approved the use of a TPTFA rider for PGL. The TPTFA rider allowed PGL to recover the costs incurred for these third-party transaction fees prior to them being included in base rates. PGL began recovering costs under the rider on February 1, 2022. Amounts deferred under the rider were being recovered over a period of 12 months and are subject to an annual reconciliation whereby costs are reviewed by the ICC for accuracy and prudency. Effective December 1, 2023, PGL discontinued its use of the TPTFA rider and began recovering costs related to these third-party transaction fees through its base rates. NSG began recovering these costs through its base rates, effective September 15, 2021.

North Shore Gas Company 2021 Rate Order

In October 2020, NSG filed a request with the ICC to increase its natural gas rates. In September 2021, the ICC issued a written order authorizing a rate increase of $4.1 million (4.5%). The rate increase reflected a 9.67% ROE and a common equity component average of 51.58%. The natural gas rate increase was primarily driven by NSG's ongoing significant investment in its distribution system since its last rate review that resulted in revised base rates effective January 28, 2015. The new rates were effective September 15, 2021.

Qualifying Infrastructure Plant Rider

In July 2013, Illinois Public Act 98-0057, The Natural Gas Consumer, Safety & Reliability Act, became law. This law provides natural gas utilities with a cost recovery mechanism that allows collection, through a surcharge on customer bills, of prudently incurred costs to upgrade Illinois natural gas infrastructure. In January 2014, the ICC approved a QIP rider for PGL, which was in effect until December 1, 2023. As discussed above, PGL has returned to the traditional rate-making process for recovery of these costs, and they are now included in PGL's base rates.

Costs previously incurred under PGL's QIP rider are still subject to an annual reconciliation whereby costs are reviewed for accuracy and prudency. In March 2023, PGL filed its 2022 reconciliation with the ICC, which, along with the reconciliations from 2016 through 2021, are still pending. Annual costs included in the rider have ranged from $192 million to $348 million.

As of December 31, 2023, there can be no assurance that all costs incurred under PGL's QIP rider during the open reconciliation years, which include 2016 through 2023, will be deemed recoverable by the ICC. Disallowances by the ICC, if any, could be material and have a material adverse impact on our results of operations.

Minnesota Energy Resources Corporation

2023 Rate Order

In November 2022, MERC initiated a rate proceeding with the MPUC to increase its retail natural gas base rates. In December 2022, the MPUC approved MERC's request for interim rates totaling $37.0 million, subject to refund. The interim rates went into effect on January 1, 2023.

On November 14, 2023, the MPUC issued a written order approving a settlement agreement MERC reached with certain intervenors. The settlement agreement reflects a natural gas base rate increase of $28.8 million (7.1%), along with a 9.65% ROE and a common equity component average of 53.0%. The natural gas rate increase was primarily driven by increased capital investments as well as inflationary pressure on operating costs. Under the terms of the settlement agreement, MERC will continue the use of its decoupling mechanism for residential customers, and it will be expanded to include certain small commercial and industrial customers. Final rates will be effective March 1, 2024.

MERC’s customers are entitled to a refund to the extent the interim rate increase exceeded the final approved rate increase. As of December 31, 2023, MERC had recorded a regulatory liability of $8.5 million for refunds due to customers. These amounts will be refunded to customers during the second quarter of 2024.

Michigan Gas Utilities Corporation

2024 Rate Application

On December 28, 2023, MGU provided notification to the MPSC of its intent to file an application requesting an increase to its natural gas rates. The application is expected to be filed in March 2024 and to request new rates be effective January 1, 2025. MGU is currently in the process of evaluating its rate request.

2023 Rate Order

In March 2023, MGU filed a request with the MPSC to increase its retail natural gas base rates. In August 2023, the MPSC issued a written order approving a comprehensive settlement that resolved all issues in MGU's rate case. The key terms of the settlement agreement include:

- a natural gas base rate increase of $9.9 million (4.7%);
- an ROE of 9.8%;
- a common equity component average of 51.0%; and,
- a continuation of the existing MRP rider, effective January 1, 2025 through 2027, including forecasted increased costs for those projects. MRP costs are being recovered in base rates in 2024.

The rate increase was primarily driven by capital investments made to strengthen the safety and reliability of MGU's natural gas distribution system and to provide service to additional customers. Inflationary pressure on operating costs also contributed to the rate increase. The new rates were effective January 1, 2024.

2021 Rate Order

In February 2020, MGU provided notification to the MPSC of its intent to file an application requesting an increase to MGU's natural gas rates to be effective January 1, 2021. However, MGU decided that it would delay its filing of the rate case as a result of the Coronavirus Disease – 2019 pandemic.

In May 2020, MGU filed an application with the MPSC requesting approval to defer $5.0 million of depreciation and interest expense during 2021 related to capital investments made by MGU since its last rate case. In July 2020, the MPSC issued a written order approving MGU's request. The deferral of these costs helped to mitigate the impacts from delaying the filing of the rate case.

In March 2021, MGU filed its request with the MPSC to increase its natural gas rates. In September 2021, the MPSC issued a written order approving a settlement agreement MGU reached with certain intervenors. The order authorized a rate increase of $9.3 million (6.35%) and reflected a 9.85% ROE and a common equity component average of 51.5%. The natural gas rate increase was primarily driven by MGU's significant investment in capital infrastructure since its previous rate review that resulted in revised base rates effective January 1, 2016. The order also allowed MGU to implement a rider for its MRP, which supports recovery of planned capital investment related to pipeline replacements to maintain system safety and reliability between 2023 and 2027, without having to file a rate case. All costs recovered through the rider are subject to a prudence review by the MPSC. The new rates were effective January 1, 2022.

Upper Michigan Energy Resources Corporation

2024 Rate Application

On December 28, 2023, UMERC provided notification to the MPSC of its intent to file an application requesting an increase to its electric rates. The application is expected to be filed in March 2024 and to request new rates be effective January 1, 2025. UMERC is currently in the process of evaluating its rate request.

Recovery of Natural Gas Costs

Due to the cold temperatures, wind, snow, and ice throughout the central part of the country during February 2021, the cost of gas purchased for our natural gas utility customers was temporarily driven significantly higher than our normal winter weather expectations. All of our utilities have regulatory mechanisms in place for recovering all prudently incurred natural gas costs.

In March 2021, WE and WG received approval from the PSCW to recover approximately $54 million and $24 million, respectively, of natural gas costs in excess of the benchmark set in their GCRMs over a period of three months, beginning in April 2021. In March 2021, WPS also filed its revised natural gas rate sheets with the PSCW reflecting approximately $28 million of natural gas costs in excess of the benchmark set in its GCRM. WPS also recovered these excess costs over a period of three months, beginning in April 2021.

PGL and NSG incurred approximately $131 million and $10 million, respectively, of natural gas costs in February 2021 in excess of the amounts included in their rates. These costs were recovered over a period of 12 months, which started on April 1, 2021. PGL's and NSG's natural gas costs were reviewed for prudency by the ICC as part of their annual natural gas cost reconciliation. In January 2023, the ICC issued written orders approving each company's 2021 reconciliation.

In February 2021, MERC incurred approximately $75 million of natural gas costs in excess of the benchmark set in its GCRM. In August 2021, the MPUC issued a written order approving a joint proposal filed by MERC and four other Minnesota utilities to recover their respective excess natural gas costs. In accordance with the order, MERC recovered $10 million of these costs through its annual natural gas true-up process over a period of 12 months, and the remaining $65 million was to be recovered over a period of 27 months, both beginning in September 2021. Recovery of these costs and the issue of prudence was referred to a contested-case proceeding. In October 2022, the MPUC issued a written order approving a settlement agreement entered into by MERC and various parties related to the recovery of the extraordinary natural gas costs incurred in February 2021. Under the settlement agreement, MERC agreed to not seek recovery of $3 million of these costs. MERC substantially recovered the remaining $62 million of extraordinary natural gas costs over the previously approved 27-month recovery period.

Natural gas costs incurred at MGU and UMERC in excess of the amount included in their respective rates were not significant.

NOTE 27—OTHER INCOME, NET

Total other income, net was as follows for the years ended December 31:

(in millions)	2023	2022	2021
Non-service components of net periodic benefit costs	**$ 97.7**	$ 104.4	$ 72.2
AFUDC-Equity	**59.1**	29.4	18.0
Gains (losses) from investments held in rabbi trust	**13.7**	(12.6)	18.6
Earnings (losses) from equity method investments [1]	**(1.1)**	9.3	19.9
Other, net	**8.3**	(1.7)	4.5
Other income, net	**$ 177.7**	$ 128.8	$ 133.2

[1] Amounts do not include equity earnings of transmission affiliates as those earnings are shown as a separate line item on the income statements.

NOTE 28—NEW ACCOUNTING PRONOUNCEMENTS

Improvements to Income Tax Disclosures

In December 2023, the FASB issued ASU No. 2023-09, Income Taxes (Topic 740): Improvements to Income Tax Disclosures. The amendments require additional disclosures, primarily related to income taxes paid and the rate reconciliation table. The amendments require disclosures on specific categories in the rate reconciliation table, as well as additional information for reconciling items that meet a quantitative threshold. For income taxes paid, additional disclosures are required to disaggregate federal, state, and foreign income taxes paid, with additional disclosures for income taxes paid that meet a quantitative threshold. The amendments are effective for annual periods beginning after December 15, 2024, with early adoption permitted. We plan to adopt these amendments beginning with our fiscal year ending on December 31, 2025, and are currently evaluating the impact this guidance may have on our financial statements and related disclosures.

Improvements to Reportable Segment Disclosures

In November 2023, the FASB issued ASU No. 2023-07, Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures. The amendments require additional disclosures about reportable segments on an annual and interim basis. The amendments require disclosure of significant segment expenses that are (1) regularly provided to the chief operating decision maker and (2) included in the reported measure of segment profit or loss. The amendments also require disclosure of an amount for other segment items and a description of its composition. The new standard also allows companies to disclose multiple measures of segment profit or loss if those measures are used to assess performance and allocate resources. The amendments are effective for fiscal years beginning after December 15, 2023, and interim periods within fiscal years beginning after December 15, 2024, with early adoption permitted. We plan to adopt these amendments beginning with our fiscal year ending on December 31, 2024, and are currently evaluating the impact this guidance may have on our financial statements and related disclosures.

Reference Rate Reform

In March 2020, the FASB issued ASU No. 2020-04, Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting and in January 2021, the FASB issued ASU No. 2021-01, Reference Rate Reform (Topic 848): Scope. These pronouncements provide temporary optional expedients and exceptions for applying GAAP principles to contract modifications and hedging relationships to ease the financial reporting burdens of the market transition from LIBOR and other interbank offered rates to alternative reference rates. These pronouncements were effective upon issuance on March 12, 2020 through December 31, 2022. In December 2022, the FASB issued ASU No. 2022-06, Reference Rate Reform (Topic 848): Deferral of the Sunset Date of Topic 848, to extend the temporary accounting rules under Topic 848 from December 31, 2022 to December 31, 2024, after which entities will no longer be permitted to apply the relief in Topic 848. An entity may elect to apply the amendments prospectively from March 12, 2020 through December 31, 2024 by accounting topic. Our $500.0 million 2007 Junior Notes, which were previously subject to a variable rate based on U.S. dollar LIBOR, became subject to a variable rate based on SOFR beginning July 1, 2023. No contract modifications were required as the references to LIBOR were replaced by operation of law. See Note 14, Long-Term Debt, for more information. We do not anticipate this guidance having a significant impact on our financial statements and related disclosures.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Our management, with the participation of our principal executive officer and principal financial officer, has evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Based upon such evaluation, our principal executive officer and principal financial officer have concluded that, as of the end of such period, our disclosure controls and procedures are effective: (i) in recording, processing, summarizing and reporting, on a timely basis, information required to be disclosed by us in the reports that we file or submit under the Exchange Act; and (ii) to ensure that information required to be disclosed in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our and our subsidiaries' internal control over financial reporting based on the framework in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation, our management concluded that our and our subsidiaries' internal control over financial reporting was effective as of December 31, 2023.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of the effectiveness of internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting (as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) during the fourth quarter of 2023 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Report of Independent Registered Public Accounting Firm

For Deloitte & Touche LLP's Report of Independent Registered Public Accounting Firm, attesting to the effectiveness of our internal controls over financial reporting, see Section A of Item 8.

ITEM 9B. OTHER INFORMATION

During the three months ended December 31, 2023, none of our directors or officers (as defined in Rule 16a-1 under the Exchange Act) adopted or terminated any contract, instruction, or written plan for the purchase or sale of our securities that was intended to satisfy the affirmative defense conditions of Rule 10b5-1(c) or any "non-Rule 10b5-1 trading arrangement" (as defined in Item 408 of Regulation S-K).

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE OF THE REGISTRANT

The information under "Proposal 1: Election of Directors – Terms Expiring in 2025 – 2024 Director Nominees for Election," "Annual Meeting Attendance and Voting Information – Stockholder Nominees and Proposals," and "Governance – Board Committees – Audit and Oversight" in our Definitive Proxy Statement on Schedule 14A to be filed with the SEC for our Annual Meeting of Shareholders to be held May 9, 2024 (the "2024 Annual Meeting Proxy Statement") is incorporated herein by reference. Also see "Information about our Executive Officers" in Part I of this report.

We have adopted a written code of ethics, referred to as our Code of Business Conduct, with which all of our directors, executive officers, and employees, including the principal executive officer, principal financial officer, and principal accounting officer, must comply with. We have posted our Code of Business Conduct on our website, www.wecenergygroup.com. We have not provided any waiver to the Code for any director, executive officer, or other employee. Any amendments to, or waivers for directors and executive officers from, the Code of Business Conduct will be disclosed on our website or in a current report on Form 8-K.

Our website, www.wecenergygroup.com, also contains our Corporate Governance Guidelines and the charters of our Audit and Oversight, Corporate Governance, and Compensation Committees.

Our Code of Business Conduct, Corporate Governance Guidelines, and committee charters are also available without charge to any shareholder of record or beneficial owner of our common stock by writing to the corporate secretary, Margaret C. Kelsey, at our principal business office, 231 West Michigan Street, P.O. Box 1331, Milwaukee, Wisconsin 53201.

ITEM 11. EXECUTIVE COMPENSATION

The information under "Compensation Discussion and Analysis," "Executive Compensation Tables," "Governance – Director Compensation," and "Governance – Compensation Committee Interlocks and Insider Participation" in the 2024 Annual Meeting Proxy Statement is incorporated herein by reference.

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

The security ownership information called for by Item 12 of Form 10-K is incorporated herein by reference to this information included under "WEC Energy Group Common Stock Ownership" in the 2024 Annual Meeting Proxy Statement.

Equity Compensation Plan Information

The following table sets forth information about our equity compensation plans as of December 31, 2023:

Plan Type	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants, and Rights (a)		Weighted Average Exercise Price of Outstanding Options, Warrants, and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Shares Reflected in Column (a)) (c)
Equity Compensation Plans Approved by Security Holders	3,015,751	$	79.57	7,763,218 [1]
Equity Compensation Plans Not Approved by Security Holders	N/A		N/A	N/A
Total	3,015,751	$	79.57	7,763,218

[1] Includes shares available for future issuance under our Omnibus Stock Incentive Plan, all of which could be granted as awards of stock options, stock appreciation rights, performance units, restricted stock, or other stock based awards.

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

The information under "Governance – Additional Governance Matters – Related Party Transactions," "Proposal 1: Election of Directors – Terms Expiring in 2025 – Board Composition – Independence," and "Governance – Board Committees" in the 2024 Annual Meeting Proxy Statement is incorporated herein by reference. A full description of the guidelines our Board uses to determine director independence is located in Appendix A of our Corporate Governance Guidelines, which can be found on the Corporate Governance section of our Company's website at www.wecenergygroup.com/govern/governance.htm.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information regarding the fees paid to, and services performed by, our independent auditors and the pre-approval policy of our audit and oversight committee under "Proposal 2: Ratification of Deloitte & Touche LLP as Independent Auditors for 2024 – Independent Auditors' Fees and Services" in the 2024 Annual Meeting Proxy Statement is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

1. Financial Statements and Reports of Independent Registered Public Accounting Firm Included in Part II of This Report

2. Financial Statement Schedules Included in Part IV of This Report

Other schedules are omitted because of the absence of conditions under which they are required or because the required information is given in the financial statements or notes thereto.

3. Exhibits and Exhibit Index

The following exhibits are filed or furnished with or incorporated by reference in the report with respect to WEC Energy Group, Inc. (File No. 001-09057). An asterisk (*) indicates that the exhibit has previously been filed with the SEC and is incorporated herein by reference. Each management contract and compensatory plan or arrangement required to be filed as an exhibit to this report pursuant to Item 15(b) of Form 10-K is identified below by two asterisks (**) following the description of the exhibit.

Number	Exhibit	
3	**Articles of Incorporation and By-laws**	
	3.1*	Restated Articles of Incorporation of WEC Energy Group, Inc., as amended effective May 21, 2012. (Exhibit 3.1 to Wisconsin Energy Corporation's 06/30/12 Form 10-Q.)
	3.2*	Articles of Amendment to the Restated Articles of Incorporation of WEC Energy Group, Inc., as amended. (Exhibit 3.1 to WEC Energy Group's 06/29/15 Form 8-K.)
	3.3*	Bylaws of WEC Energy Group, Inc., as amended to January 19, 2023. (Exhibit 3.1 to WEC Energy Group's 01/20/23 Form 8-K.)

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Number	Exhibit
4	**Instruments defining the rights of security holders, including indentures**

4.1* Reference is made to Article III of the Restated Articles of Incorporation and the Bylaws of WEC Energy Group, Inc. (See Exhibits 3.1 and 3.3 above.)

4.2* Description of WEC Energy Group's Common Stock. (Exhibit 4.2 to WEC Energy Group's 12/31/2019 Form 10-K.)

4.3* Replacement Capital Covenant, dated May 11, 2007, by Wisconsin Energy Corporation for the benefit of certain debtholders named therein. (Exhibit 4.2 to Wisconsin Energy Corporation's 05/08/07 Form 8-K.)

4.4* Amendment to Replacement Capital Covenant, dated as of June 29, 2015. (Exhibit 4.1 to WEC Energy Group's 06/29/15 Form 8-K.)

Indentures and Securities Resolutions:

4.5* Indenture for Debt Securities of Wisconsin Electric Power Company (the "Wisconsin Electric Indenture"), dated December 1, 1995. (Exhibit (4)-1 under File No. 1-1245, WE's 12/31/95 Form 10-K.)

4.6* Securities Resolution No. 1 of Wisconsin Electric under the Wisconsin Electric Indenture, dated December 5, 1995. (Exhibit (4)-2 under File No. 1-1245, WE's 12/31/95 Form 10-K.)

4.7* Securities Resolution No. 3 of Wisconsin Electric under the Wisconsin Electric Indenture, dated May 27, 1998. (Exhibit (4)-1 under File No. 1-1245, WE’s 06/30/98 Form 10-Q.)

4.8* Securities Resolution No. 5 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of May 1, 2003. (Exhibit 4.47 filed with Post-Effective Amendment No. 1 to Wisconsin Electric's Registration Statement on Form S-3. (File No. 333-101054), filed May 6, 2003.)

4.9* Securities Resolution No. 7 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of November 2, 2006. (Exhibit 4.1 under File No. 1-1245, WE's 11/02/06 Form 8-K.)

4.10* Securities Resolution No. 12 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of December 5, 2012. (Exhibit 4.1 under File No. 1-1245, WE's 12/05/12 Form 8-K.)

4.11* Securities Resolution No. 14 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of May 12, 2014. (Exhibit 4.1 under File No. 1-1245, WE's 05/12/14 Form 8-K.)

4.12* Securities Resolution No. 15 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of May 14, 2015. (Exhibit 4.1 under File No. 1-1245, WE's 05/14/15 Form 8-K.)

4.13* Securities Resolution No. 16 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of November 13, 2015. (Exhibit 4.1 under File No. 1-1245, WE's 11/13/15 Form 8-K.)

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Number	Exhibit
4.19*	Securities Resolution No. 4 of Wisconsin Energy Corporation under the Wisconsin Energy Indenture, dated as of March 17, 2003. (Exhibit 4.12 filed with Post-Effective Amendment No. 1 to Wisconsin Energy Corporation's Registration Statement on Form S-3 (File No. 333-69592), filed March 20, 2003.)
4.20*	Securities Resolution No. 5 of Wisconsin Energy Corporation under the Wisconsin Energy Indenture, effective as of May 8, 2007. (Exhibit 4.1 to Wisconsin Energy Corporation's 05/08/07 Form 8-K.)
4.21*	Securities Resolution No. 6 of Wisconsin Energy Corporation under the Wisconsin Energy Indenture, effective as of June 4, 2015. (Exhibit 4.1 to Wisconsin Energy Corporation's 06/04/15 Form 8-K.)
4.22*	Securities Resolution No. 10 of WEC Energy Group under the Wisconsin Energy Indenture, effective as of October 5, 2020. (Exhibit 4.1 to WEC Energy Group's 10/05/20 Form 8-K.)
4.23*	Securities Resolution No. 11 of WEC Energy Group under the Wisconsin Energy Indenture, dated as of March 16, 2021. (Exhibit 4.1 to WEC Energy Group's 03/19/21 Form 8-K.)
4.24*	Securities Resolution No. 12 of WEC Energy Group under the Wisconsin Energy Indenture, dated as of December 6, 2021. (Exhibit 4.1 to WEC Energy Group's 12/13/21 Form 8-K.)
4.25*	Securities Resolution No. 13 of WEC Energy Group under the Wisconsin Energy Indenture, dated as of September 22, 2022. (Exhibit 4.1 to WEC Energy Group's 9/27/22 Form 8-K.)
4.26*	Securities Resolution No. 14 of WEC Energy Group under the Wisconsin Energy Indenture, dated as of January 9, 2023. (Exhibit 4.1 to WEC Energy Group's 01/11/23 Form 8-K.)
4.27*	Securities Resolution No. 15 of WEC Energy Group under the Wisconsin Energy Indenture, dated as of September 12, 2023. (Exhibit 4.1 to WEC Energy Group's 09/12/23 Form 8-K.)
4.28*	Indenture, dated as of December 1, 1998, between Wisconsin Public Service Corporation ("WPS") and U.S. Bank National Association (successor to Firstar Bank Milwaukee, N.A., National Association) (Exhibit 4A to Form 8-K filed December 18, 1998) (File No. 1-3016).
4.29*	First Supplemental Indenture, dated as of December 1, 1998, between WPS and Firstar Bank Milwaukee, N.A., National Association (Exhibit 4C to Form 8-K filed December 18, 1998) (File No. 1-3016).
4.30*	Fifth Supplemental Indenture, dated as of December 1, 2006, by and between WPS and U.S. Bank National Association (Exhibit 4.1 to Form 8-K filed November 30, 2006) (File No. 1-3016).
4.31*	Ninth Supplemental Indenture, dated as of December 1, 2012, by and between WPS and U.S. Bank National Association (Exhibit 4.1 to Form 8-K filed November 29, 2012) (File No. 1-3016).

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Number	Exhibit
10	**Material Contracts**

10.1*	WEC Energy Group Supplemental Pension Plan, Amended and Restated Effective as of January 1, 2018.**
10.2*	Legacy Wisconsin Energy Corporation Executive Deferred Compensation Plan, Amended and Restated as of January 1, 2018.**
10.3*	WEC Energy Group Executive Deferred Compensation Plan, Amended and Restated Effective as of January 1, 2018.**
10.4	Amendment dated as of December 20, 2023 to the WEC Energy Group Executive Deferred Compensation Plan, Amended and Restated Effective as of January 1, 2018.**
10.5*	Legacy Wisconsin Energy Corporation Directors' Deferred Compensation Plan, Amended and Restated Effective as of January 1, 2017. (Exhibit 10.4 to WEC Energy Group's 12/31/16 Form 10-K.)**
10.6*	WEC Energy Group Directors' Deferred Compensation Plan, Amended and Restated Effective as of January 1, 2017. (Exhibit 10.5 to WEC Energy Group's 12/31/16 Form 10-K.)**
10.7*	WEC Energy Group Non-Qualified Retirement Savings Plan, Amended and Restated Effective as of January 1, 2018.**
10.8*	WEC Energy Group Supplemental Long Term Disability Plan, Amended and Restated Effective as of January 1, 2017.**
10.9*	WEC Energy Group Short-Term Performance Plan, Amended and Restated Effective as of January 1, 2019.**
10.10*	Wisconsin Energy Corporation 2014 Rabbi Trust by and between Wisconsin Energy Corporation and The Northern Trust Company dated February 23, 2015, regarding the trust established to provide a source of funds to assist in meeting the liabilities under various nonqualified deferred compensation plans made between Wisconsin Energy Corporation or its subsidiaries and various plan participants. (Exhibit 10.13 to Wisconsin Energy Corporation's 12/31/14 Form 10K.)**
10.11*	Letter Agreement by and between WEC Energy Group, Inc. and Xia Liu, dated March 24, 2020. (Exhibit 10.2 to WEC Energy Group's 03/31/20 Form 8-K.)**
10.12*	Letter Agreement by and between WEC Energy Group, Inc. and Gale E. Klappa, dated as of October 21, 2020. (Exhibit 10.1 to WEC Energy Group's 10/21/2020 Form 8-K.)**
10.13*	Letter Agreement by and between WEC Energy Group, Inc. and Gale E. Klappa, dated as of November 8, 2023. (Exhibit 10.1 to WEC Energy Group's 11/09/2023 Form 8-K.)**
10.14*	Letter Agreement by and between Wisconsin Energy Corporation and Robert Garvin, dated January 31, 2011. (Exhibit 10.1 to Wisconsin Energy

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Number	Exhibit
10.19*	WEC Energy Group Performance Unit Plan, amended and restated effective as of January 1, 2023. (Exhibit 10.1 to WEC Energy Group's 12/02/22 Form 8-K.)**
10.20*	Wisconsin Energy Corporation Terms and Conditions Governing Non-Qualified Stock Option Award for option awards under the WEC Energy Group Omnibus Stock Incentive Plan, approved December 4, 2014. (Exhibit 10.3 to Wisconsin Energy Corporation's 12/04/14 Form 8-K.)**
10.21*	2016 WEC Energy Group Terms and Conditions Governing Non-Qualified Stock Option Award for option awards under the WEC Energy Group Omnibus Stock Incentive Plan. (Exhibit 10.29 to WEC Energy Group's 12/31/15 Form 10-K.)**
10.22*	Non-Qualified Stock Option Award Terms and Conditions under the WEC Energy Group Omnibus Stock Incentive Plan. (Exhibit 10.2 to WEC Energy Group's 06/30/21 Form 10-Q.)**
10.23*	Restricted Stock Award Terms and Conditions under the WEC Energy Group Omnibus Stock Incentive Plan. (Exhibit 10.3 to WEC Energy Group's 06/30/21 Form 10-Q.)**
10.24*	Restricted Stock Award Terms and Conditions under the WEC Energy Group Omnibus Stock Incentive Plan (1 Year Vesting). (Exhibit 10.4 to WEC Energy Group's 06/30/21 Form 10-Q.)**
10.25*	Director Restricted Stock Award Terms and Conditions under the WEC Energy Group Omnibus Stock Incentive Plan. (Exhibit 10.5 to WEC Energy Group's 06/30/21 Form 10-Q.)**
10.26*	Port Washington I Facility Lease Agreement between Port Washington Generating Station, LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of May 28, 2003. (Exhibit 10.7 to WE's 06/30/03 Form 10-Q (File No. 001-01245).)
10.27*	Port Washington II Facility Lease Agreement between Port Washington Generating Station, LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of May 28, 2003. (Exhibit 10.8 to WE's 06/30/03 Form 10-Q (File No. 001-01245).)
10.28*	Elm Road I Facility Lease Agreement between Elm Road Generating Station Supercritical, LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of November 9, 2004. (Exhibit 10.56 to Wisconsin Energy Corporation's 12/31/04 Form 10-K.)
10.29*	Elm Road II Facility Lease Agreement between Elm Road Generating Station Supercritical, LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of November 9, 2004. (Exhibit 10.57 to Wisconsin Energy Corporation's 12/31/04 Form 10-K.)
10.30*	Point Beach Nuclear Plant Power Purchase Agreement between FPL Energy Point Beach, LLC and Wisconsin Electric Power Company, dated as of December 19, 2006 (the "PPA"). (Exhibit 10.1 to Wisconsin Energy Corporation's 03/31/08 Form 10-Q.)
10.31*	Letter Agreement between Wisconsin Electric Power Company and FPL Energy

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Number	Exhibit	
31	**Rule 13a-14(a) / 15d-14(a) Certifications**	
	31.1	Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
	31.2	Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	**Section 1350 Certifications**	
	32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
	32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
97	**Policy Relating to Recovery of Erroneously Awarded Compensation**	
	97.1	Incentive-Based Compensation Clawback Policy ("Rule 10D-1 Policy")
101	**Interactive Data File**	
	101.INS	Inline XBRL Instance Document – the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document
	101.SCH	Inline XBRL Taxonomy Extension Schema
	101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase
	101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase
	101.LAB	Inline XBRL Taxonomy Extension Label Linkbase
	101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase
104	**Cover Page Interactive Date File (formatted as Inline XBRL and contained in Exhibit 101)**	

ITEM 16. FORM 10-K SUMMARY

None.

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SCHEDULE I
CONDENSED PARENT COMPANY FINANCIAL STATEMENTS
WEC ENERGY GROUP, INC. (PARENT COMPANY ONLY)

A. INCOME STATEMENTS

Year Ended December 31 (in millions)	2023	2022	2021
Operating expenses (income)	**$ 2.5**	$ (1.6)	$ 12.0
Equity earnings of subsidiaries	**1,502.5**	1,473.0	1,367.0
Other income, net	**19.6**	2.4	1.7
Interest expense	**260.8**	109.6	70.2
Loss on debt extinguishment	**—**	—	23.1
Income before income taxes	**1,258.8**	1,367.4	1,263.4
Income tax benefit	**72.9**	40.7	36.9
Net income attributed to common shareholders	**$ 1,331.7**	$ 1,408.1	$ 1,300.3

The accompanying Notes to Condensed Parent Company Financial Statements are an integral part of these financial statements.

B. STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31 (in millions)	2023	2022	2021
Net income attributed to common shareholders	**$ 1,331.7**	$ 1,408.1	$ 1,300.3
Other comprehensive income (loss), net of tax			
Derivatives accounted for as cash flow hedges			
Net derivative gain, net of tax	**—**	—	0.6
Reclassification of realized net derivative (gain) loss to net income, net of tax	**(0.3)**	(0.3)	0.9
Cash flow hedges, net	**(0.3)**	(0.3)	1.5
Defined benefit plans			
Pension and OPEB adjustments arising during the period, net of tax	**(0.2)**	(0.8)	0.4
Amortization of pension and OPEB costs included in net periodic benefit cost, net of tax	**0.1**	0.2	0.3
Defined benefit plans, net	**(0.1)**	(0.6)	0.7
Other comprehensive income (loss) from subsidiaries, net of tax	**(0.5)**	(2.7)	1.4
Other comprehensive income (loss), net of tax	**(0.9)**	(3.6)	3.6
Comprehensive income attributed to common shareholders	**$ 1,330.8**	$ 1,404.5	$ 1,303.9

The accompanying Notes to Condensed Parent Company Financial Statements are an integral part of these financial statements.

C. BALANCE SHEETS

At December 31 (in millions)	2023	2022
Assets		
Current assets		
Accounts receivable from related parties	**$ 2.7**	$ 0.7
Notes receivable from related parties	**16.0**	30.9
Prepaid income taxes	**—**	35.4
Other	**0.2**	0.1
Current assets	**18.9**	67.1
Long-term assets		
Investments in subsidiaries	**18,307.2**	16,533.4
Note receivable from WECI	**430.0**	—
Other	**22.9**	24.2
Long-term assets	**18,760.1**	16,557.6
Total assets	**$ 18,779.0**	$ 16,624.7
Liabilities and Equity		
Current liabilities		
Short-term debt	**$ 697.0**	$ 399.7
Current portion of long-term debt	**600.0**	700.0
Accounts payable to related parties	**2.9**	2.0
Notes payable to related parties	**459.6**	332.5
Other	**73.2**	31.8
Current liabilities	**1,832.7**	1,466.0
Long-term liabilities		
Long-term debt	**5,192.8**	3,747.2
Other	**29.3**	34.6
Long-term liabilities	**5,222.1**	3,781.8
Common shareholders' equity	**11,724.2**	11,376.9
Total liabilities and equity	**$ 18,779.0**	$ 16,624.7

The accompanying notes to Condensed Parent Company Financial Statements are an integral part of these financial statements.

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D. STATEMENTS OF CASH FLOWS

Year Ended December 31 (in millions)	2023	2022	2021
Operating activities			
Net income attributed to common shareholders	**$ 1,331.7**	$ 1,408.1	$ 1,300.3
Reconciliation to cash provided by operating activities			
Equity income in subsidiaries, net of distributions	**(566.8)**	(437.4)	(571.3)
Deferred income taxes, net	**(3.8)**	11.6	(1.9)
Loss on debt extinguishment	**—**	—	23.1
Change in –			
Accounts receivable from related parties	**(2.0)**	(0.1)	0.1
Prepaid income taxes	**35.4**	21.1	(2.1)
Other current assets	**(0.1)**	—	—
Accounts payable to related parties	**0.9**	(3.5)	(26.2)
Accrued interest	**42.1**	15.4	0.4
Other current liabilities	**(0.7)**	(5.1)	8.2
Other, net	**14.4**	5.8	(2.5)
Net cash provided by operating activities	**851.1**	1,015.9	728.1
Investing activities			
Capital contributions to subsidiaries	**(1,807.4)**	(1,099.7)	(734.0)
Return of capital from subsidiaries	**175.2**	372.9	196.1
Short-term notes receivable from related parties, net	**14.9**	(1.9)	81.8
Other, net	**—**	(2.0)	(1.1)
Net cash used in investing activities	**(1,617.3)**	(730.7)	(457.2)
Financing activities			
Exercise of stock options	**6.3**	33.6	15.7
Purchase of common stock	**(16.6)**	(69.2)	(33.1)
Dividends paid on common stock	**(984.2)**	(917.9)	(854.8)
Issuance of long-term debt	**2,050.0**	900.0	1,100.0
Retirement of long-term debt	**(700.0)**	—	(300.0)
Repayment of short-term loan	**—**	—	(340.0)
Change in commercial paper	**297.3**	(336.4)	255.7
Short-term notes payable to related parties, net	**127.1**	112.1	(82.6)
Payments for debt extinguishment and issuance costs	**(13.3)**	(6.7)	(33.9)
Other, net	**(0.4)**	(1.2)	(1.4)
Net cash provided by (used in) financing activities	**766.2**	(285.7)	(274.4)
Net change in cash and cash equivalents	**—**	(0.5)	(3.5)
Cash and cash equivalents at beginning of year	**—**	0.5	4.0
Cash and cash equivalents at end of year	**$ —**	$ —	$ 0.5

The accompanying Notes to Condensed Parent Company Financial Statements are an integral part of these financial statements.

SCHEDULE I
CONDENSED PARENT COMPANY FINANCIAL STATEMENTS
WEC ENERGY GROUP, INC. (PARENT COMPANY ONLY)

E. NOTES TO PARENT COMPANY FINANCIAL STATEMENTS

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

For Parent Company only presentation, investments in subsidiaries are accounted for using the equity method. We use the cumulative earnings approach for classifying distributions received in the statements of cash flows.

The condensed Parent Company financial statements and notes should be read in conjunction with the consolidated financial statements and notes of WEC Energy Group, Inc. appearing in this Annual Report on Form 10-K.

NOTE 2—CASH DIVIDENDS RECEIVED FROM SUBSIDIARIES

Dividends received from our subsidiaries during the years ended December 31 were as follows:

(in millions)	**2023**	**2022**	**2021**
WE	**$ 370.0**	$ 630.0	$ 360.0
We Power	**192.8**	158.5	217.9
WG	**171.0**	60.0	30.0
WECI [1]	**93.7**	87.7	46.4
ATC Holding [2]	**86.8**	74.9	106.4
UMERC	**21.0**	17.0	—
Wispark [3]	**0.4**	7.5	—
Bluewater	**—**	—	35.0
Total	**$ 935.7**	$ 1,035.6	$ 795.7

(1) We also received amounts classified as return of capital of $171.6 million, $363.7 million, and $164.1 million from WECI during the years ended December 31, 2023, 2022, and 2021, respectively.

(2) We also received an amount classified as return of capital of $32.0 million from ATC Holding during the year ended December 31, 2021.

(3) We also received amounts classified as return of capital of $3.6 million and $9.2 million from Wispark during the years ended December 31, 2023 and 2022.

NOTE 3—LONG-TERM DEBT

The following table shows the future maturities of our long-term debt outstanding as of December 31, 2023:

(in millions)	
2024	$ 600.0
2025	620.0
2026	1,600.0
2027	900.0
2028	950.0
Thereafter	1,150.0
Total	$ 5,820.0

WECC is our subsidiary and has $50.0 million of long-term notes outstanding. In a Support Agreement between WECC and us, we agreed to make sufficient liquid asset contributions to WECC to permit WECC to service its debt obligations as they become due.

NOTE 4—FAIR VALUE MEASUREMENTS

The following table shows the financial instruments included on our balance sheets that are not recorded at fair value as of December 31:

(in millions)	2023 Carrying Amount	2023 Fair Value	2022 Carrying Amount	2022 Fair Value
Long-term notes receivable from WECI	**$ 430.0**	**$ 425.7**	$ —	$ —
Long-term debt, including current portion	**5,792.8**	**5,596.0**	4,447.2	4,095.6

The fair value of our long-term notes receivable and long-term debt are categorized within Level 2 of the fair value hierarchy.

NOTE 5—GUARANTEES

The following table shows our outstanding guarantees on behalf of our subsidiaries:

(in millions)	Total Amounts Committed at December 31, 2023	Expiration: Less Than 1 Year	Expiration: 1 to 3 Years	Expiration: Over 3 Years
Guarantees supporting business operations [(1)]	**$ 191.7**	$ 14.4	$ —	$ 177.3
Standby letters of credit [(2)]	**75.1**	24.5	—	50.6
Surety bonds [(3)]	**33.6**	33.6	—	—
Other guarantees [(4)]	**11.6**	—	—	11.6
Total guarantees	**$ 312.0**	$ 72.5	$ —	$ 239.5

(1) Consists of $177.3 million, $10.2 million, and $4.2 million of guarantees to support the business operations of WECI, Bluewater, and UMERC, respectively.

(2) At our request or the request of our subsidiaries, financial institutions have issued standby letters of credit for the benefit of third parties that have extended credit to our subsidiaries. These amounts are not reflected on our balance sheets.

(3) Primarily for environmental remediation, workers compensation self-insurance programs, and obtaining various licenses, permits, and rights-of-way. These amounts are not reflected on our balance sheets.

(4) Related to workers compensation coverage for which a liability was recorded on our balance sheets.

NOTE 6—SUPPLEMENTAL CASH FLOW INFORMATION

(in millions)	2023	2022	2021
Cash paid for interest	**$ 209.1**	$ 88.1	$ 70.2
Cash received for income taxes, net	**(104.5)**	(72.9)	(27.9)
Significant non-cash equity transaction:			
Issuance of long-term note receivable to WECI	**430.0**	—	—

NOTE 7—SHORT-TERM NOTES RECEIVABLE FROM RELATED PARTIES

The following table shows our outstanding short-term notes receivable from related parties as of December 31:

(in millions)	2023	2022
UMERC	**$ 15.2**	$ 27.1
Wispark	**0.8**	1.1
Bluewater	**—**	2.7
Total	**$ 16.0**	$ 30.9

NOTE 8—SHORT-TERM NOTES PAYABLE TO RELATED PARTIES

The following table shows our outstanding short-term notes payable to related parties as of December 31:

(in millions)	2023	2022
Integrys	**$ 257.0**	$ 115.0
WECC	**109.2**	106.5
WBS	**91.8**	111.0
Bluewater	**1.6**	—
Total	**$ 459.6**	$ 332.5

SCHEDULE II
WEC ENERGY GROUP, INC.
VALUATION AND QUALIFYING ACCOUNTS

Allowance for Doubtful Accounts (in millions)	Balance at Beginning of Period	Expense [1]	Deferral	Net Write-offs [2]	Balance at End of Period
December 31, 2023	**$ 199.3**	**$ 72.0**	**$ 88.3**	**$ (166.1)**	**$ 193.5**
December 31, 2022	198.3	86.1	62.9	(148.0)	199.3
December 31, 2021	220.1	107.4	(44.8)	(84.4)	198.3

(1) Net of recoveries.

(2) Represents amounts written off to the reserve, net of adjustments to regulatory assets.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

WEC ENERGY GROUP, INC.

By /s/ SCOTT J. LAUBER

Date: February 22, 2024

Scott J. Lauber
President and Chief Executive Officer

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Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

/s/ SCOTT J. LAUBER Scott J. Lauber, President and Chief Executive Officer, and Director -- Principal Executive Officer	February 22, 2024
/s/ XIA LIU Xia Liu, Executive Vice President and Chief Financial Officer -- Principal Financial Officer	February 22, 2024
/s/ WILLIAM J. GUC William J. Guc, Vice President and Controller -- Principal Accounting Officer	February 22, 2024
/s/ GALE E. KLAPPA Gale E. Klappa, Executive Chairman and Director	February 22, 2024
/s/ AVE M. BIE Ave M. Bie, Director	February 22, 2024
/s/ CURT S. CULVER Curt S. Culver, Director	February 22, 2024
/s/ DANNY L. CUNNINGHAM Danny L. Cunningham, Director	February 22, 2024
/s/ WILLIAM M. FARROW, III William M. Farrow, III, Director	February 22, 2024
/s/ CRISTINA A. GARCIA-THOMAS Cristina A. Garcia-Thomas, Director	February 22, 2024
/s/ MARIA C. GREEN Maria C. Green, Director	February 22, 2024
/s/ THOMAS K. LANE Thomas K. Lane, Director	February 22, 2024
/s/ ULICE PAYNE, JR. Ulice Payne, Jr., Director	February 22, 2024
/s/ MARY ELLEN STANEK Mary Ellen Stanek, Director	February 22, 2024
/s/ GLEN E. TELLOCK Glen E. Tellock, Director	February 22, 2024