UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2025

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.
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

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 is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ☐ No ☒

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date (June 30, 2025):

Common Stock, $.01 Par Value, 321,866,395 shares outstanding

WEC ENERGY GROUP, INC.
QUARTERLY REPORT ON FORM 10-Q
For the Quarter Ended June 30, 2025
TABLE OF CONTENTS

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
Blooming Grove	Blooming Grove Wind Energy Center LLC
Bluewater	Bluewater Natural Gas Holding, LLC
Delilah I	Delilah Solar Energy LLC
Hardin III	Hardin Solar III Energy Center
Integrys	Integrys Holding, Inc.
Jayhawk	Jayhawk Wind, LLC
MERC	Minnesota Energy Resources Corporation
MGU	Michigan Gas Utilities Corporation
NSG	North Shore Gas Company
PGL	The Peoples Gas Light and Coke Company
Samson I	Samson I Solar Energy Center LLC
Tatanka Ridge	Tatanka Ridge Wind LLC
UMERC	Upper Michigan Energy Resources Corporation
WE	Wisconsin Electric Power Company
We Power	W.E. Power, LLC
WEC Energy Group	WEC Energy Group, Inc.
WECI	WEC Infrastructure LLC
WECI Energy Holding III	WEC Infrastructure Energy Holding III LLC
WEPCo Environmental Trust	WEPCo Environmental Trust Finance I, LLC
WG	Wisconsin Gas LLC
WPS	Wisconsin Public Service Corporation

Federal and State Regulatory Agencies

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
MPSC	Michigan Public Service Commission
PSCW	Public Service Commission of Wisconsin
SEC	United States Securities and Exchange Commission
USITC	United States International Trade Commission
WDNR	Wisconsin Department of Natural Resources

Accounting Terms

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

Environmental Terms

BATW	Bottom Ash Transport Water
BTA	Best Technology Available
CAA	Clean Air Act

CASAC	Clean Air Scientific Advisory Committee
CCR	Coal Combustion Residuals
CO_2	Carbon Dioxide
CRL	Combustine Residual Leachate
CWA	Clean Water Act
ELG	Steam Electric Effluent Limitation Guidelines
FGD	Flue Gas Desulfurization
GHG	Greenhouse Gas
GHG Power Plant Rule	2024 Greenhouse Gas Power Plant Rule
MATS	Mercury and Air Toxics Standards
NAAQS	National Ambient Air Quality Standards
NOV	Notice of Violation
NOx	Nitrogen Oxide
PM	Particulate Matter
WPDES	Wisconsin Pollutant Discharge Elimination System

Measurements	
Bcf	Billion Cubic Feet
Dth	Dekatherm
lb/MMBtu	Pound Per Million British Thermal Unit
MW	Megawatt
MWh	Megawatt-hours
µg/m3	Micrograms Per Cubic Meter

Other Terms and Abbreviations	
2024A Junior Notes	WEC Energy Group, Inc.'s Series 2024A 6.69% Fixed-to-Fixed Reset Rate Junior Subordinated Notes Due June 15, 2055
2024B Junior Notes	WEC Energy Group, Inc.'s Series 2024B 6.69% Fixed-to-Fixed Reset Rate Junior Subordinated Notes Due June 15, 2055
2027 Notes	WEC Energy Group, Inc.'s 4.375% Convertible Senior Notes Due 2027
2028 Notes	WEC Energy Group, Inc.'s 3.375% Convertible Senior Notes Due 2028
2029 Notes	WEC Energy Group, Inc.'s 4.375% Convertible Senior Notes Due 2029
AD	Antidumping
AI	Artificial Intelligence
AMI	Advanced Metering Infrastructure
AREP	Amended Renewable Energy Plan
Badger Hollow Wind	Badger Hollow Wind Energy Generation Facility
CABO	Clean and Affordable Buildings Ordinance
Chicago, IL-IN-WI	Chicago, Illinois, Indiana, and Wisconsin
CODM	Chief Operating Decision Maker
Columbia	Columbia Energy Center
Compensation Committee	Compensation Committee of the Board of Directors
CVD	Countervailing Duty
D.C. Circuit Court of Appeals	United States Court of Appeals for the District of Columbia Circuit
Darien	Darien Solar Park
DRER	Dedicated Renewable Energy Resource
EDA	Equity Distribution Agreement
Edgewater	Edgewater Generating Station
EPS	Earnings Per Share
ERGS	Elm Road Generating Station
ETB	Environmental Trust Bond
EV	Electric Vehicle
Exchange Act	Securities Exchange Act of 1934, as amended
FTR	Financial Transmission Right
Good Oak	Good Oak Solar Generation Facility
Gristmill	Gristmill Solar Generation Facility
High Noon	High Noon Solar Energy Center

IRA	Inflation Reduction Act
ITC	Investment Tax Credit
LDC	Local Natural Gas Distribution Company
LNG	Liquefied Natural Gas
MG&E	Madison Gas and Electric Company
MISO	Midcontinent Independent System Operator, Inc.
NOPP	Notice of Planned Participation
OBBBA	One Big Beautiful Bill Act
OCPP	Oak Creek Power Plant
Paris	Paris Solar-Battery Park
PIPP	Presque Isle Power Plant
PPA	Power Purchase Agreement
PRP	Pipe Replacement Program
PTC	Production Tax Credit
Pulliam	J.P. Pulliam Generating Station
QIP	Qualifying Infrastructure Plant
Renegade	Renegade Solar Energy Center
RICE	Reciprocating Internal Combustion Engine
RNG	Renewable Natural Gas
ROE	Return on Equity
S&P	Standard & Poor's
Saratoga	Saratoga Solar Electric Generation and BESS Facility
SIP	State Implementation Plan
Supreme Court	United States Supreme Court
Tax Legislation	Tax Cuts and Jobs Act of 2017
TCR	Transmission Congestion Act
UEA	Uncollectible Expense Adjustment
UFLPA	Uyghur Forced Labor Prevention Act
Ursa	Ursa Solar Electric Generation Facility
VAPP	Valley Power Plant
VLC	Very Large Customer
West Riverside	West Riverside Energy Center
Weston	Weston Generating Station
Whitetail	Whitetail Wind Energy Generation Facility
WPL	Wisconsin Power and Light Company

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 capital 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 risk factors as set forth in our 2024 Annual Report on Form 10-K, 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, electric grid reliability, 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, including continued economic growth, customer growth and declines, including our ability to develop and/or acquire new generation to meet demand from data centers and other large customers, commodity prices, energy conservation efforts, and continued adoption of distributed generation by customers or co-location of generation near data centers;

- 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 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 and uncertainty regarding the interpretation of regulations or permit conditions by regulatory agencies including as a result of the current presidential administration, 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 changes to U.S. trade policy (including changes to tariffs on imports, port fees, and other trade policy tools) as well as changes to foreign governments' trade policies impacting U.S. exports, supply chain disruptions (including 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;

- Risks inherent in electric generation and distribution and natural gas transportation, distribution, and storage activities, including leaks, accidental explosions, mechanical problems, fires, discharges or releases of toxic or hazardous substances or gases, and risks related to the ability to obtain adequate insurance to cover such events;

- Factors affecting the implementation of our CO_2 emission reduction goal and related opportunities and actions, including related regulatory decisions, the cost of materials, supplies, and labor, technology advances, significant increases in demand, 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 or international conflicts, including those in Ukraine, Israel, and other 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 involved in developing and implementing AI, including data privacy concerns or other legal liability, new or enhanced governmental or regulatory scrutiny or regulations governing the use of AI, the ability to meet expectations or requirements relating to adoption or implementation of AI technology, or other complications related to the use of AI;

- 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, pricing differentials between the facilities' point of interconnection and our required delivery location, the ability to replace expiring PPAs under acceptable terms, rights to property on which our projects are located but we do not own, the availability of reliable interconnection and electricity grids, the performance and quality of the wind turbine and solar panel components and availability of replacement parts, 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 and their possible impairment;

- 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. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

WEC ENERGY GROUP, INC.

CONDENSED CONSOLIDATED INCOME STATEMENTS (Unaudited)	**Three Months Ended June 30**		**Six Months Ended June 30**	
(in millions, except per share amounts)	**2025**	**2024**	**2025**	**2024**
Operating revenues	**$ 2,009.5**	$ 1,772.0	**$ 5,159.0**	$ 4,452.2
Operating expenses				
Cost of sales	**570.5**	469.7	**1,736.2**	1,396.8
Other operation and maintenance	**596.2**	533.4	**1,204.2**	1,064.2
Depreciation and amortization	**368.9**	336.6	**728.8**	670.0
Property and revenue taxes	**69.0**	67.5	**147.4**	143.0
Total operating expenses	**1,604.6**	1,407.2	**3,816.6**	3,274.0
Operating income	**404.9**	364.8	**1,342.4**	1,178.2
Equity in earnings of transmission affiliates	**51.9**	46.8	**105.5**	91.6
Other income, net	**26.5**	40.6	**44.6**	84.7
Interest expense	**220.8**	200.6	**443.8**	392.6
Other expense	**(142.4)**	(113.2)	**(293.7)**	(216.3)
Income before income taxes	**262.5**	251.6	**1,048.7**	961.9
Income tax expense	**19.5**	41.6	**80.2**	129.3
Net income	**243.0**	210.0	**968.5**	832.6
Preferred stock dividends of subsidiary	**0.3**	0.3	**0.6**	0.6
Net loss attributed to noncontrolling interests	**2.7**	1.6	**1.7**	1.6
Net income attributed to common shareholders	**$ 245.4**	$ 211.3	**$ 969.6**	$ 833.6
EPS				
Basic	**$ 0.77**	$ 0.67	**$ 3.04**	$ 2.64
Diluted	**$ 0.76**	$ 0.67	**$ 3.02**	$ 2.64
Weighted average common shares outstanding				
Basic	**320.3**	315.9	**319.3**	315.8
Diluted	**322.2**	316.2	**320.7**	316.1

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

WEC ENERGY GROUP, INC.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (Unaudited)	Three Months Ended June 30		Six Months Ended June 30	
(in millions)	**2025**	**2024**	**2025**	**2024**
Net income	**$ 243.0**	$ 210.0	**$ 968.5**	$ 832.6
Other comprehensive income (loss), net of tax				
Derivatives accounted for as cash flow hedges				
Reclassification of realized derivative gains to net income, net of tax	**(0.1)**	—	**(0.2)**	(0.1)
Defined benefit plans				
Amortization of pension and OPEB costs included in net periodic benefit cost, net of tax	**0.1**	—	**0.1**	—
Other comprehensive loss, net of tax	**—**	—	**(0.1)**	(0.1)
Comprehensive income	**243.0**	210.0	**968.4**	832.5
Preferred stock dividends of subsidiary	**0.3**	0.3	**0.6**	0.6
Comprehensive loss attributed to noncontrolling interests	**2.7**	1.6	**1.7**	1.6
Comprehensive income attributed to common shareholders	**$ 245.4**	$ 211.3	**$ 969.5**	$ 833.5

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

WEC ENERGY GROUP, INC.

CONDENSED CONSOLIDATED BALANCE SHEETS (Unaudited) ***(in millions, except share and per share amounts)***	**June 30, 2025**	**December 31, 2024**
Assets		
Current assets		
Cash and cash equivalents	**$ 23.0**	$ 9.8
Accounts receivable and unbilled revenues, net of reserves of $142.2 and $162.8, respectively	**1,496.4**	1,669.3
Materials, supplies, and inventories	**703.0**	813.2
Prepaid taxes	**209.0**	214.9
Other prepayments	**51.4**	82.6
Other	**116.3**	121.9
Current assets	**2,599.1**	2,911.7
Long-term assets		
Property, plant, and equipment, net of accumulated depreciation and amortization of $12,025.9 and $11,611.9, respectively	**36,060.8**	34,645.4
Regulatory assets (June 30, 2025 and December 31, 2024 include $72.2 and $76.5, respectively, related to WEPCo Environmental Trust)	**3,231.8**	3,339.7
Equity investment in transmission affiliates	**2,200.1**	2,108.9
Goodwill	**3,052.8**	3,052.8
Pension and OPEB assets	**1,000.4**	968.5
Other	**379.3**	336.2
Long-term assets	**45,925.2**	44,451.5
Total assets	**$ 48,524.3**	$ 47,363.2
Liabilities and Equity		
Current liabilities		
Short-term debt	**$ 810.3**	$ 1,116.6
Current portion of long-term debt (June 30, 2025 and December 31, 2024 include $9.2, related to WEPCo Environmental Trust)	**2,250.4**	1,729.0
Accounts payable	**816.5**	1,137.1
Other	**820.4**	859.2
Current liabilities	**4,697.6**	4,841.9
Long-term liabilities		
Long-term debt (June 30, 2025 and December 31, 2024 include $71.9 and $76.4, respectively, related to WEPCo Environmental Trust)	**17,110.4**	17,178.1
Finance lease obligations	**361.8**	303.3
Deferred income taxes	**5,739.5**	5,514.7
Deferred revenue, net	**323.9**	334.6
Regulatory liabilities	**4,039.0**	3,958.0
Intangible liabilities	**609.7**	566.8
Environmental remediation liabilities	**438.9**	445.8
AROs	**616.4**	580.0
Other	**917.0**	838.1
Long-term liabilities	**30,156.6**	29,719.4
Commitments and contingencies (Note 21)		
Common shareholders' equity		
Common stock – $0.01 par value; 650,000,000 shares authorized; 321,866,395 and 317,680,855 shares outstanding, respectively	**3.2**	3.2
Additional paid in capital	**4,743.1**	4,315.8
Retained earnings	**8,484.7**	8,083.8
Accumulated other comprehensive loss	**(7.9)**	(7.8)
Common shareholders' equity	**13,223.1**	12,395.0
Preferred stock of subsidiary	**30.4**	30.4
Noncontrolling interests	**416.6**	376.5
Total liabilities and equity	**$ 48,524.3**	$ 47,363.2

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

WEC ENERGY GROUP, INC.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)	Six Months Ended June 30	
(in millions)	**2025**	**2024**
Operating activities		
Net income	**$ 968.5**	$ 832.6
Reconciliation to cash provided by operating activities		
Depreciation and amortization	**728.8**	670.0
Deferred income taxes and ITCs, net	**220.0**	321.5
Contributions and payments related to pension and OPEB plans	**(7.1)**	(7.5)
Equity income in transmission affiliates, net of distributions	**(3.4)**	(19.6)
Change in –		
Accounts receivable and unbilled revenues, net	**136.4**	254.2
Materials, supplies, and inventories	**110.2**	79.4
Other current assets	**65.4**	49.5
Accounts payable	**(172.1)**	(90.3)
Customer credit balances	**(38.4)**	(57.4)
Other current liabilities	**(6.4)**	(53.1)
Other, net	**14.0**	(78.3)
Net cash provided by operating activities	**2,015.9**	1,901.0
Investing activities		
Capital expenditures	**(1,530.5)**	(1,138.4)
Acquisition of Hardin III, net of cash acquired of $0.2	**(406.1)**	—
Acquisition of West Riverside	**—**	(98.2)
Capital contributions to transmission affiliates	**(87.8)**	(30.3)
Proceeds from the sale of investments held in rabbi trust	**16.9**	14.8
Reimbursement for ATC's transmission infrastructure upgrades	**39.7**	6.2
Other, net	**(5.0)**	(4.9)
Net cash used in investing activities	**(1,972.8)**	(1,250.8)
Financing activities		
Exercise of stock options	**24.7**	4.7
Issuance of common stock, net	**398.8**	38.2
Purchase of common stock	**(1.3)**	(3.2)
Dividends paid on common stock	**(568.7)**	(527.2)
Issuance of long-term debt	**1,025.0**	2,074.2
Retirement of long-term debt	**(567.6)**	(785.4)
Change in commercial paper	**(308.0)**	(1,260.4)
Purchase of additional ownership interest in Samson I from noncontrolling interest	**—**	(28.1)
Payments for debt extinguishment and issuance costs	**(16.7)**	(23.6)
Other, net	**(2.3)**	(1.7)
Net cash used in financing activities	**(16.1)**	(512.5)
Net change in cash, cash equivalents, and restricted cash	**27.0**	137.7
Cash, cash equivalents, and restricted cash at beginning of period	**42.2**	165.2
Cash, cash equivalents, and restricted cash at end of period	**$ 69.2**	$ 302.9

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

WEC ENERGY GROUP, INC.

CONDENSED CONSOLIDATED STATEMENTS OF EQUITY (Unaudited)

	WEC Energy Group Common Shareholders' Equity							
(in millions, except per share amounts)	Common Stock	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Shareholders' Equity	Preferred Stock of Subsidiary	Non-controlling Interests	Total Equity
Balance at December 31, 2024	$ 3.2	$ 4,315.8	$ 8,083.8	$ (7.8)	$ 12,395.0	$ 30.4	$ 376.5	$ 12,801.9
Net income attributed to common shareholders	—	—	724.2	—	724.2	—	—	724.2
Net income attributed to noncontrolling interests	—	—	—	—	—	—	1.0	1.0
Other comprehensive loss	—	—	—	(0.1)	(0.1)	—	—	(0.1)
Issuance of common stock, net	—	117.1	—	—	117.1	—	—	117.1
Common stock dividends of $0.8925 per share	—	—	(283.6)	—	(283.6)	—	—	(283.6)
Exercise of stock options	—	21.2	—	—	21.2	—	—	21.2
Purchase of common stock	—	(1.3)	—	—	(1.3)	—	—	(1.3)
Acquisition of noncontrolling interests	—	—	—	—	—	—	45.1	45.1
Distributions to noncontrolling interests	—	—	—	—	—	—	(1.8)	(1.8)
Stock-based compensation and other	—	3.3	—	—	3.3	—	—	3.3
Balance at March 31, 2025	$ 3.2	$ 4,456.1	$ 8,524.4	$ (7.9)	$ 12,975.8	$ 30.4	$ 420.8	$ 13,427.0
Net income attributed to common shareholders	—	—	245.4	—	245.4	—	—	245.4
Net loss attributed to noncontrolling interests	—	—	—	—	—	—	(2.7)	(2.7)
Issuance of common stock, net	—	281.7	—	—	281.7	—	—	281.7
Common stock dividends of $0.8925 per share	—	—	(285.1)	—	(285.1)	—	—	(285.1)
Exercise of stock options	—	3.5	—	—	3.5	—	—	3.5
Distributions to noncontrolling interests	—	—	—	—	—	—	(1.5)	(1.5)
Stock-based compensation and other	—	1.8	—	—	1.8	—	—	1.8
Balance at June 30, 2025	$ 3.2	$ 4,743.1	$ 8,484.7	$ (7.9)	$ 13,223.1	$ 30.4	$ 416.6	$ 13,670.1

(in millions, except per share amounts)	WEC Energy Group Common Shareholders' Equity: Common Stock	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Shareholders' Equity	Preferred Stock of Subsidiary	Non-controlling Interests	Total Equity
Balance at December 31, 2023	$ 3.2	$ 4,115.9	$ 7,612.8	$ (7.7)	$ 11,724.2	$ 30.4	$ 316.9	$ 12,071.5
Net income attributed to common shareholders	—	—	622.3	—	622.3	—	—	622.3
Other comprehensive loss	—	—	—	(0.1)	(0.1)	—	—	(0.1)
Issuance of common stock, net	—	19.2	—	—	19.2	—	—	19.2
Common stock dividends of $0.8350 per share	—	—	(263.5)	—	(263.5)	—	—	(263.5)
Exercise of stock options	—	3.7	—	—	3.7	—	—	3.7
Purchase of common stock	—	(2.0)	—	—	(2.0)	—	—	(2.0)
Purchase of additional ownership interest in Samson I from noncontrolling interest	—	4.3	—	—	4.3	—	(32.4)	(28.1)
Distributions to noncontrolling interests	—	—	—	—	—	—	(1.5)	(1.5)
Stock-based compensation and other	—	4.6	—	—	4.6	—	—	4.6
Balance at March 31, 2024	$ 3.2	$ 4,145.7	$ 7,971.6	$ (7.8)	$ 12,112.7	$ 30.4	$ 283.0	$ 12,426.1
Net income attributed to common shareholders	—	—	211.3	—	211.3	—	—	211.3
Net loss attributed to noncontrolling interests	—	—	—	—	—	—	(1.6)	(1.6)
Issuance of common stock, net	—	19.0	—	—	19.0	—	—	19.0
Common stock dividends of $0.8350 per share	—	—	(263.7)	—	(263.7)	—	—	(263.7)
Exercise of stock options	—	1.0	—	—	1.0	—	—	1.0
Purchase of common stock	—	(1.2)	—	—	(1.2)	—	—	(1.2)
Distributions to noncontrolling interests	—	—	—	—	—	—	(0.3)	(0.3)
Stock-based compensation and other	—	3.8	—	—	3.8	—	—	3.8
Balance at June 30, 2024	$ 3.2	$ 4,168.3	$ 7,919.2	$ (7.8)	$ 12,082.9	$ 30.4	$ 281.1	$ 12,394.4

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

WEC ENERGY GROUP, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)
June 30, 2025

NOTE 1—GENERAL INFORMATION

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 condensed 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. In this report, when we refer to "the Company," "us," "we," "our," or "ours," we are referring to WEC Energy Group and all of its subsidiaries.

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 sheets related to the minority interests held by third parties in the renewable generating facilities that are included in our non-utility energy infrastructure segment.

We use the equity method to account for investments in companies we do not control but over which we exercise significant influence regarding their operating and financial policies. As a result of our limited voting rights, we account for ATC and ATC Holdco as equity method investments. See Note 18, Investment in Transmission Affiliates, for more information.

We have prepared the unaudited interim financial statements presented in this Form 10-Q pursuant to the rules and regulations of the SEC and GAAP. Accordingly, these financial statements do not include all of the information and footnotes required by GAAP for annual financial statements. These financial statements should be read in conjunction with the consolidated financial statements and footnotes in our Annual Report on Form 10-K for the year ended December 31, 2024. Financial results for an interim period may not give a true indication of results for the year. In particular, the results of operations for the three and six months ended June 30, 2025, are not necessarily indicative of expected results for 2025 due to seasonal variations and other factors.

In management's opinion, we have included all adjustments, normal and recurring in nature, necessary for a fair presentation of our financial results.

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 the below acquisitions met the criteria of asset acquisitions. The purchase price of the Hardin III and Samson I acquisitions below includes intangibles recorded as long-term liabilities related to PPAs. See Note 17, Goodwill and Intangibles, for more information.

Acquisition of Electric Generation Facilities in Wisconsin

In May 2024, WE completed the acquisition of 100 MWs of West Riverside's nameplate capacity for $98.2 million. West Riverside is a commercially operational dual fueled combined cycle generation facility in Beloit, Wisconsin. Prior to the acquisition, WPS received approval to transfer its ownership interest rights to WE. Including this acquisition, WE owns 200 MWs, or 27.5%, of West Riverside at a total cost of $193.5 million.

Acquisition of a Solar Generation Facility in Ohio

In February 2025, WECI completed the acquisition of a 90% ownership interest in Hardin III, a 250 MW solar generating facility located in Hardin County, Ohio for $406.1 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. Hardin III qualifies for PTCs and is included in the non-utility energy infrastructure segment.

Acquisitions of 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, Franklin, Hopkins, and Red River counties in Texas. 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 in May 2022. 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.

NOTE 3—OPERATING REVENUES

For more information about our operating revenues, see Note 1(d), Operating Revenues, in our 2024 Annual Report on Form 10-K.

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 Energy Group Consolidated
Three Months Ended June 30, 2025								
Electric	**$ 1,303.1**	**$ —**	**$ —**	**$ 1,303.1**	**$ —**	**$ —**	**$ —**	**$ 1,303.1**
Natural gas	**277.1**	**280.5**	**76.5**	**634.1**	**11.4**	**—**	**(10.6)**	**634.9**
Total regulated revenues	**1,580.2**	**280.5**	**76.5**	**1,937.2**	**11.4**	**—**	**(10.6)**	**1,938.0**
Other non-utility revenues	**—**	**—**	**5.4**	**5.4**	**58.1**	**—**	**(3.9)**	**59.6**
Total revenues from contracts with customers	**1,580.2**	**280.5**	**81.9**	**1,942.6**	**69.5**	**—**	**(14.5)**	**1,997.6**
Other operating revenues	**7.0**	**(9.9)**	**0.4**	**(2.5)**	**119.9**	**—**	**(105.5)** (1)	**11.9**
Total operating revenues	**$ 1,587.2**	**$ 270.6**	**$ 82.3**	**$ 1,940.1**	**$ 189.4**	**$ —**	**$ (120.0)**	**$ 2,009.5**

(in millions)	Wisconsin	Illinois	Other States	Total Utility Operations	Non-Utility Energy Infrastructure	Corporate and Other	Reconciling Eliminations	WEC Energy Group Consolidated
Three Months Ended June 30, 2024								
Electric	$ 1,148.5	$ —	$ —	$ 1,148.5	$ —	$ —	$ —	$ 1,148.5
Natural gas	215.1	255.5	63.4	534.0	11.4	—	(10.8)	534.6
Total regulated revenues	1,363.6	255.5	63.4	1,682.5	11.4	—	(10.8)	1,683.1
Other non-utility revenues	—	—	4.9	4.9	59.3	—	(3.9)	60.3
Total revenues from contracts with customers	1,363.6	255.5	68.3	1,687.4	70.7	—	(14.7)	1,743.4
Other operating revenues	4.6	21.3	2.7	28.6	104.9	—	(104.9) (1)	28.6
Total operating revenues	$ 1,368.2	$ 276.8	$ 71.0	$ 1,716.0	$ 175.6	$ —	$ (119.6)	$ 1,772.0

(in millions)	Wisconsin	Illinois	Other States	Total Utility Operations	Non-Utility Energy Infrastructure	Corporate and Other	Reconciling Eliminations	WEC Energy Group Consolidated
Six Months Ended June 30, 2025								
Electric	**$ 2,623.1**	**$ —**	**$ —**	**$ 2,623.1**	**$ —**	**$ —**	**$ —**	**$ 2,623.1**
Natural gas	**1,011.2**	**1,039.8**	**300.2**	**2,351.2**	**25.5**	**—**	**(24.0)**	**2,352.7**
Total regulated revenues	**3,634.3**	**1,039.8**	**300.2**	**4,974.3**	**25.5**	**—**	**(24.0)**	**4,975.8**
Other non-utility revenues	**—**	**—**	**10.9**	**10.9**	**119.6**	**—**	**(5.5)**	**125.0**
Total revenues from contracts with customers	**3,634.3**	**1,039.8**	**311.1**	**4,985.2**	**145.1**	**—**	**(29.5)**	**5,100.8**
Other operating revenues	**12.8**	**19.1**	**(1.7)**	**30.2**	**238.6**	**—**	**(210.6)** [(1)]	**58.2**
Total operating revenues	**$ 3,647.1**	**$ 1,058.9**	**$ 309.4**	**$ 5,015.4**	**$ 383.7**	**$ —**	**$ (240.1)**	**$ 5,159.0**

(in millions)	Wisconsin	Illinois	Other States	Total Utility Operations	Non-Utility Energy Infrastructure	Corporate and Other	Reconciling Eliminations	WEC Energy Group Consolidated
Six Months Ended June 30, 2024								
Electric	$ 2,333.8	$ —	$ —	$ 2,333.8	$ —	$ —	$ —	$ 2,333.8
Natural gas	801.1	859.3	237.0	1,897.4	25.9	—	(25.0)	1,898.3
Total regulated revenues	3,134.9	859.3	237.0	4,231.2	25.9	—	(25.0)	4,232.1
Other non-utility revenues	—	—	9.9	9.9	111.4	—	(5.5)	115.8
Total revenues from contracts with customers	3,134.9	859.3	246.9	4,241.1	137.3	—	(30.5)	4,347.9
Other operating revenues	12.1	83.5	8.7	104.3	209.2	—	(209.2) [(1)]	104.3
Total operating revenues	$ 3,147.0	$ 942.8	$ 255.6	$ 4,345.4	$ 346.5	$ —	$ (239.7)	$ 4,452.2

[(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:

	Three Months Ended June 30		Six Months Ended June 30	
(in millions)	2025	2024	2025	2024
Residential	**$ 511.9**	$ 458.6	**$ 1,056.9**	$ 941.8
Small commercial and industrial	**423.3**	383.6	**844.4**	775.3
Large commercial and industrial	**257.8**	224.9	**496.1**	442.5
Other	**7.4**	7.2	**15.4**	15.1
Total retail revenues	**1,200.4**	1,074.3	**2,412.8**	2,174.7
Wholesale	**25.8**	27.7	**53.5**	53.3
Resale	**65.7**	37.8	**128.5**	82.9
Steam	**5.6**	4.1	**18.4**	14.3
Other utility revenues	**5.6**	4.6	**9.9**	8.6
Total electric utility operating revenues	**$ 1,303.1**	$ 1,148.5	**$ 2,623.1**	$ 2,333.8

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
Three Months Ended June 30, 2025				
Residential	**$ 160.3**	**$ 227.2**	**$ 46.0**	**$ 433.5**
Commercial and industrial	**77.9**	**58.5**	**22.1**	**158.5**
Total retail revenues	**238.2**	**285.7**	**68.1**	**592.0**
Transportation	**22.7**	**60.1**	**7.6**	**90.4**
Other utility revenues [1]	**16.2**	**(65.3)**	**0.8**	**(48.3)**
Total natural gas utility operating revenues	**$ 277.1**	**$ 280.5**	**$ 76.5**	**$ 634.1**

(in millions)	Wisconsin	Illinois	Other States	Total Natural Gas Utility Operating Revenues
Three Months Ended June 30, 2024				
Residential	$ 124.9	$ 162.1	$ 30.1	$ 317.1
Commercial and industrial	53.2	41.5	16.2	110.9
Total retail revenues	178.1	203.6	46.3	428.0
Transportation	21.3	52.5	6.2	80.0
Other utility revenues [1]	15.7	(0.6)	10.9	26.0
Total natural gas utility operating revenues	$ 215.1	$ 255.5	$ 63.4	$ 534.0

(in millions)	Wisconsin	Illinois	Other States	Total Natural Gas Utility Operating Revenues
Six Months Ended June 30, 2025				
Residential	**$ 649.1**	**$ 692.8**	**$ 188.7**	**$ 1,530.6**
Commercial and industrial	**328.3**	**189.7**	**95.2**	**613.2**
Total retail revenues	**977.4**	**882.5**	**283.9**	**2,143.8**
Transportation	**55.9**	**157.5**	**21.1**	**234.5**
Other utility revenues [1]	**(22.1)**	**(0.2)**	**(4.8)**	**(27.1)**
Total natural gas utility operating revenues	**$ 1,011.2**	**$ 1,039.8**	**$ 300.2**	**$ 2,351.2**

(in millions)	Wisconsin	Illinois	Other States	Total Natural Gas Utility Operating Revenues
Six Months Ended June 30, 2024				
Residential	$ 522.5	$ 537.1	$ 141.5	$ 1,201.1
Commercial and industrial	245.0	148.5	70.2	463.7
Total retail revenues	767.5	685.6	211.7	1,664.8
Transportation	51.1	142.6	17.8	211.5
Other utility revenues [1]	(17.5)	31.1	7.5	21.1
Total natural gas utility operating revenues	$ 801.1	$ 859.3	$ 237.0	$ 1,897.4

(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, compared with the recovery of natural gas costs that were anticipated in rates.

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. All amounts associated with the service agreements with WE, WPS, and WG have been eliminated at the consolidated level.

[Table of Contents](#)

Other Non-Utility Operating Revenues

Other non-utility operating revenues consist primarily of the following:

	Three Months Ended June 30		Six Months Ended June 30	
(in millions)	**2025**	**2024**	**2025**	**2024**
Renewable generation revenues	**$ 48.1**	$ 49.3	**$ 101.9**	$ 93.8
We Power revenues	**6.1**	6.1	**12.2**	12.1
Appliance service revenues	**5.4**	4.9	**10.9**	9.9
Total other non-utility operating revenues	**$ 59.6**	$ 60.3	**$ 125.0**	$ 115.8

Other Operating Revenues

Other operating revenues consist primarily of the following:

	Three Months Ended June 30		Six Months Ended June 30	
(in millions)	**2025**	**2024**	**2025**	**2024**
Late payment charges	**$ 13.9**	$ 14.1	**$ 27.7**	$ 28.7
Alternative revenues [1]	**(18.3)**	12.3	**—**	72.8
Other	**16.3**	2.2	**30.5**	2.8
Total other operating revenues	**$ 11.9**	$ 28.6	**$ 58.2**	$ 104.3

[1] Alternative revenues consist of amounts to be recovered or refunded to customers subject to decoupling mechanisms, wholesale true-ups, and conservation improvement rider true-ups. Negative amounts can result from alternative revenues being reversed to revenues from contracts with customers as the customer is billed for these alternative revenues. For more information about our alternative revenues, see Note 1(d), Operating Revenues, in our 2024 Annual Report on Form 10-K.

NOTE 4—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.

Table of Contents

We have included tables below that show our gross third-party receivable balances and the related allowance for credit losses at June 30, 2025 and December 31, 2024, by reportable segment.

(in millions)	Wisconsin	Illinois	Other States	Total Utility Operations	Non-Utility Energy Infrastructure	Corporate and Other	WEC Energy Group Consolidated
June 30, 2025							
Accounts receivable and unbilled revenues	**$ 1,059.7**	**$ 460.7**	**$ 57.6**	**$ 1,578.0**	**$ 54.6**	**$ 6.0**	**$ 1,638.6**
Allowance for credit losses	**52.3**	**84.6**	**5.3**	**142.2**	**—**	**—**	**142.2**
Accounts receivable and unbilled revenues, net [1]	**$ 1,007.4**	**$ 376.1**	**$ 52.3**	**$ 1,435.8**	**$ 54.6**	**$ 6.0**	**$ 1,496.4**
Total accounts receivable, net – past due greater than 90 days [1]	**$ 52.2**	**$ 50.5**	**$ 3.6**	**$ 106.3**	**$ —**	**$ —**	**$ 106.3**
Past due greater than 90 days – collection risk mitigated by regulatory mechanisms [1]	**94.6 %**	**100.0 %**	**— %**	**94.0 %**	**— %**	**— %**	**94.0 %**

(in millions)	Wisconsin	Illinois	Other States	Total Utility Operations	Non-Utility Energy Infrastructure	Corporate and Other	WEC Energy Group Consolidated
December 31, 2024							
Accounts receivable and unbilled revenues	$ 1,149.9	$ 535.6	$ 100.6	$ 1,786.1	$ 40.0	$ 6.0	$ 1,832.1
Allowance for credit losses	73.6	83.9	5.3	162.8	—	—	162.8
Accounts receivable and unbilled revenues, net [1]	$ 1,076.3	$ 451.7	$ 95.3	$ 1,623.3	$ 40.0	$ 6.0	$ 1,669.3
Total accounts receivable, net – past due greater than 90 days [1]	$ 51.8	$ 30.1	$ 2.5	$ 84.4	$ —	$ —	$ 84.4
Past due greater than 90 days – collection risk mitigated by regulatory mechanisms [1]	93.8 %	100.0 %	— %	93.2 %	— %	— %	93.2 %

[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 June 30, 2025, $911.9 million, or 60.9%, of our net accounts receivable and unbilled revenues balance had regulatory protections in place to mitigate the exposure to credit losses. See Note 23, Regulatory Environment, for more information on PGL and NSG's UEA rider for cost recovery or refund of uncollectible expense based on the difference between actual uncollectible write-offs and amounts recovered in rates.

A roll-forward of the allowance for credit losses by reportable segment is included below:

Three Months Ended June 30, 2025 *(in millions)*	Wisconsin	Illinois	Other States	WEC Energy Group Consolidated
Balance at April 1, 2025	**$ 60.9**	**$ 93.2**	**$ 5.3**	**$ 159.4**
Provision for credit losses	**21.7**	**13.4**	**0.3**	**35.4**
Provision for credit losses deferred for future recovery or refund	**(5.7)**	**(16.5)**	**—**	**(22.2)**
Write-offs charged against the allowance	**(38.5)**	**(15.7)**	**(0.6)**	**(54.8)**
Recoveries of amounts previously written off	**13.9**	**10.2**	**0.3**	**24.4**
Balance at June 30, 2025	**$ 52.3**	**$ 84.6**	**$ 5.3**	**$ 142.2**

Six Months Ended June 30, 2025 *(in millions)*	**Wisconsin**	**Illinois**	**Other States**	**WEC Energy Group Consolidated**
Balance at January 1, 2025	**$ 73.6**	**$ 83.9**	**$ 5.3**	**$ 162.8**
Provision for credit losses	**37.8**	**29.7**	**0.5**	**68.0**
Provision for credit losses deferred for future recovery or refund	**(13.0)**	**(14.3)**	**—**	**(27.3)**
Write-offs charged against the allowance	**(72.3)**	**(41.3)**	**(1.3)**	**(114.9)**
Recoveries of amounts previously written off	**26.2**	**26.6**	**0.8**	**53.6**
Balance at June 30, 2025	**$ 52.3**	**$ 84.6**	**$ 5.3**	**$ 142.2**

On a consolidated basis, there was a $20.6 million decrease in the allowance for credit losses at June 30, 2025, compared to January 1, 2025. This decrease is largely driven by customer write-offs in Wisconsin in addition to a decrease in past due account balances that we believe was related to a continued focus on collection efforts and the lower energy bills typically seen in the spring and summer months, enabling customers to pay down their arrears.

Three Months Ended June 30, 2024 *(in millions)*	**Wisconsin**	**Illinois**	**Other States**	**WEC Energy Group Consolidated**
Balance at April 1, 2024	$ 83.0	$ 104.6	$ 3.1	$ 190.7
Provision for credit losses	9.8	12.2	1.7	23.7
Provision for credit losses deferred for future recovery or refund	1.4	(7.5)	—	(6.1)
Write-offs charged against the allowance	(35.9)	(22.3)	(1.1)	(59.3)
Recoveries of amounts previously written off	10.4	6.2	1.3	17.9
Balance at June 30, 2024	$ 68.7	$ 93.2	$ 5.0	$ 166.9

Six Months Ended June 30, 2024 *(in millions)*	**Wisconsin**	**Illinois**	**Other States**	**WEC Energy Group Consolidated**
Balance at January 1, 2024	$ 77.4	$ 109.7	$ 6.4	$ 193.5
Provision for credit losses	23.6	27.3	(1.3)	49.6
Provision for credit losses deferred for future recovery or refund	17.1	(6.2)	—	10.9
Write-offs charged against the allowance	(71.5)	(50.3)	(2.4)	(124.2)
Recoveries of amounts previously written off	22.1	12.7	2.3	37.1
Balance at June 30, 2024	$ 68.7	$ 93.2	$ 5.0	$ 166.9

On a consolidated basis, there was a $26.6 million decrease in the allowance for credit losses at June 30, 2024, compared to January 1, 2024, largely driven by customer write-offs related to the winter moratorium months ending. After a customer is disconnected for a period of time without payment on their account, we will write off that customer balance. Also contributing to the decrease in the allowance for credit losses were lower required reserve percentages at many of our regulated utilities as a result of an improvement in loss rates. We also believe that the lower energy costs that customers were seeing, which were driven by warmer than normal weather conditions and low average natural gas prices, contributed to a reduction in past due accounts receivable balances and a related decrease in the allowance for credit losses.

Table of Contents

NOTE 5—REGULATORY ASSETS AND LIABILITIES

The following regulatory assets and liabilities were reflected on our balance sheets at June 30, 2025 and December 31, 2024. For more information on our regulatory assets and liabilities, see Note 6, Regulatory Assets and Liabilities, in our 2024 Annual Report on Form 10-K.

(in millions)	June 30, 2025	December 31, 2024
Regulatory assets		
Plant retirement related items	**$ 800.6**	$ 810.5
Pension and OPEB costs	**637.5**	684.9
Environmental remediation costs	**527.3**	570.1
Income tax related items	**465.5**	438.5
AROs	**177.0**	166.7
Uncollectible expense	**122.1**	151.5
Decoupling	**110.8**	110.0
System support resource	**97.7**	102.9
Securitization	**72.2**	76.5
Bluewater	**49.6**	57.7
Finance and operating leases	**27.8**	22.0
Derivatives	**20.7**	38.2
Energy efficiency programs	**19.1**	26.5
Energy costs recoverable through rate adjustments	**15.9**	8.3
Other, net	**112.2**	114.4
Total regulatory assets	**$ 3,256.0**	$ 3,378.7
Balance sheet presentation		
Other current assets	**$ 24.2**	$ 39.0
Regulatory assets	**3,231.8**	3,339.7
Total regulatory assets	**$ 3,256.0**	$ 3,378.7

(in millions)	June 30, 2025	December 31, 2024
Regulatory liabilities		
Income tax related items	**$ 1,809.5**	$ 1,825.4
Removal costs	**1,520.0**	1,458.2
Pension and OPEB benefits	**297.3**	308.5
Energy costs refundable through rate adjustments	**233.4**	160.8
Uncollectible expense	**64.4**	47.2
Derivatives	**56.7**	36.9
Revenue requirements of renewable generation facilities	**32.0**	44.2
Property tax [(1)]	**20.0**	19.3
Energy efficiency programs	**17.6**	14.6
Electric transmission costs	**3.9**	19.7
Other, net	**76.7**	68.5
Total regulatory liabilities	**$ 4,131.5**	$ 4,003.3
Balance sheet presentation		
Other current liabilities	**$ 92.5**	$ 45.3
Regulatory liabilities	**4,039.0**	3,958.0
Total regulatory liabilities	**$ 4,131.5**	$ 4,003.3

[(1)] In accordance with MERC's property tax tracker, MERC defers as a regulatory asset or liability the difference between actual property tax expense and the amount included in rates until recovery or refund is authorized in a future rate proceeding.

NOTE 6—PROPERTY, PLANT, AND EQUIPMENT

Wisconsin Segment Plant to be Retired

Oak Creek Power Plant Units 7-8

As a result of a PSCW approval in December 2022 for the acquisition and construction of Darien, the retirement of OCPP Units 7 and 8 became probable. Subsequently, we have received PSCW approval for several other renewable and other projects and have also acquired additional projects. On June 25, 2025, we announced plans to extend the lives of OCPP Units 7 and 8, and expect to have the units available to meet high energy demand periods through the end of 2026. These units were originally scheduled to be retired at the end of 2025. The total net book value of WE's ownership share of OCPP Units 7 and 8 was $639.3 million at June 30, 2025, 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 Energy Center 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 the end of 2029, and we and the other co-owners are exploring the conversion of at least one unit to natural gas. The total net book value of WPS's ownership share of Columbia Units 1 and 2 was $243.4 million at June 30, 2025, 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.

Samson I Solar Energy Center LLC and Delilah Solar Energy LLC – Storm Damage

During several storms that occurred in 2023 and 2024, certain sections of our Samson I solar facility incurred damage. We had previously recognized an impairment loss of $2.8 million related to damage from these storms, and recorded an offsetting $2.8 million receivable for future insurance recoveries. However, in the second quarter of 2025, we determined it was no longer probable that we would receive insurance proceeds sufficient to recover our losses associated with the 2023 and 2024 storms. As a result, the insurance receivable balance was written off, resulting in the recognition of the $2.8 million impairment loss within other operation and maintenance expense on our income statement.

In addition, in March 2025, both our Samson I and Delilah I solar facilities experienced damage from a storm. In the second quarter of 2025, we recognized an impairment loss within other operation and maintenance expense on our income statement in the amount of $8.8 million, related to damage incurred associated with the March 2025 storm.

NOTE 7—COMMON EQUITY

Stock-Based Compensation

During the six months ended June 30, 2025, the Compensation Committee of our Board of Directors awarded the following stock-based compensation to our directors, officers, and certain other key employees:

Award Type	Number of Awards
Stock options [1]	231,024
Restricted shares [2]	79,170
Performance units	185,945

(1) Stock options awarded had a weighted-average exercise price of $94.55 and a weighted-average grant date fair value of $18.23 per option.

(2) Restricted shares awarded had a weighted-average grant date fair value of $94.55 per share.

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 LLC (which holds our ownership interest in ATC), 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. Our utility subsidiaries, with the exception of UMERC and MGU, are prohibited from loaning funds to us, either directly or indirectly. See Note 11, Common Equity, in our 2024 Annual Report on Form 10-K for additional information on these and other restrictions.

We do not believe that these restrictions will materially affect our operations or limit any dividend payments in the foreseeable future.

Common Stock

As of January 1, 2024, we began issuing new shares of common stock to fulfill our obligations under various stock-based employee benefit and compensation plans and to provide shares to participants in our dividend reinvestment and stock purchase plan.

In August 2024, we entered into an EDA, under which we may offer and sell, from time to time, shares of our common stock having an aggregate sales price of up to $1.5 billion through an at-the-market offering program, which includes an equity forward sales component. We may offer and sell our common shares through the sales agents party to the EDA during the term of the agreement. The EDA will terminate upon the earliest of (i) the sale of all common stock subject to the EDA, (ii) termination of the EDA pursuant to its terms, or (iii) August 31, 2027. Actual sales of common stock under the EDA will depend on a variety of factors, including market conditions, the trading price of our common stock, capital needs, and our determination of the appropriate sources of funding. Any shares offered and sold will be done pursuant to our registration statement on Form S-3 filed with the SEC on August 5, 2024 and the related prospectus supplement. As of June 30, 2025, we had issued 4,535,041 shares of common stock under the EDA and received proceeds of $466.0 million, which is net of $5.7 million of commissions and other fees. We have not entered into any forward sale agreements.

We had the following changes to our outstanding common stock during the three and six months ended June 30, 2025 and 2024:

	Three Months Ended June 30		Six Months Ended June 30	
	2025	**2024**	**2025**	**2024**
Common stock shares outstanding at beginning of period	319,133,501	315,822,587	317,680,855	315,434,531
Shares issued:				
At-the-market offering program	**2,526,543**	—	**3,504,367**	—
Stock-based compensation	**47,403**	20,488	**390,114**	162,666
401(k)	**71,800**	122,300	**115,100**	246,600
Stock investment plan	**87,148**	114,026	**175,959**	235,604
Common stock shares outstanding at end of period	**321,866,395**	316,079,401	**321,866,395**	316,079,401

On July 17, 2025, our Board of Directors declared a quarterly cash dividend of $0.8925 per share, payable on September 1, 2025, to shareholders of record on August 14, 2025.

Earnings Per Share

The following table shows the computation of our basic and diluted EPS for the three and six months ended June 30, 2025 and 2024:

	Three Months Ended June 30		Six Months Ended June 30	
(in millions)	2025	2024	2025	2024
Numerator:				
Net income attributed to common shareholders	**$ 245.4**	$ 211.3	**$ 969.6**	$ 833.6
Denominator:				
Weighted average basic shares outstanding	**320.3**	315.9	**319.3**	315.8
Dilutive effect of stock-based compensation awards	**0.6**	0.3	**0.5**	0.3
Dilutive effect of convertible senior notes	**1.3**	—	**0.9**	—
Weighted average diluted shares	**322.2**	316.2	**320.7**	316.1
Basic EPS	**$ 0.77**	$ 0.67	**$ 3.04**	$ 2.64
Diluted EPS	**$ 0.76**	$ 0.67	**$ 3.02**	$ 2.64

NOTE 8—SHORT-TERM DEBT AND LINES OF CREDIT

The following table shows our short-term borrowings and their corresponding weighted-average interest rates:

(in millions, except percentages)	June 30, 2025	December 31, 2024
Commercial paper		
Amount outstanding	**$ 806.4**	$ 1,114.4
Weighted-average interest rate on amounts outstanding	**4.53 %**	4.63 %
Operating expense loans		
Amount outstanding [(1)]	**$ 3.9**	$ 2.2

(1) Coyote Ridge Wind, LLC, Tatanka Ridge, Jayhawk, and Samson I 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 the six months ended June 30, 2025 was $1,106.2 million with a weighted-average interest rate during the period of 4.60%.

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:

(in millions)	Maturity	June 30, 2025
WEC Energy Group	September 2026	**$ 1,500.0**
WEC Energy Group	October 2025	**200.0**
WE	September 2026	**500.0**
WPS	September 2026	**400.0**
WG	September 2026	**350.0**
PGL	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		**806.4**
Available capacity under existing agreements		**$ 2,491.3**

NOTE 9—LONG-TERM DEBT

WEC Energy Group, Inc.

In June 2025, the remaining $120.0 million outstanding of our 3.55% Senior Notes, due June 15, 2025, matured, and principal and accrued interest were paid with proceeds received from issuing commercial paper.

Convertible Senior Notes

In June 2025, we issued $900.0 million of 2028 Notes. The 2028 Notes are senior unsecured obligations and bear interest at an annual rate of 3.375%, payable semiannually beginning on December 1, 2025. Proceeds from the offering were used to repay short-term debt and for general corporate purposes.

The 2028 Notes will mature on June 1, 2028, unless earlier converted or repurchased in accordance with their terms. No sinking fund is provided for 2028 Notes. Upon the occurrence of a fundamental change, as defined in the related indenture, holders may require us to repurchase for cash all or any portion of their 2028 Notes. We may not redeem the 2028 Notes prior to their maturity date. Any fundamental change repurchases of the 2028 Notes will be at a price equal to 100% of the principal amount, plus accrued and unpaid interest.

Holders may convert all or any portion of their notes at their option at any time prior to the close of business on the business day immediately preceding March 1, 2028, only under the following circumstances:

- During any calendar quarter commencing after the calendar quarter ending on September 30, 2025, (and only during such calendar quarter), if the last reported sale price of our common stock for at least 20 trading days (whether or not consecutive) during a period of 30 consecutive trading days ending on, and including, the last trading day of the immediately preceding calendar quarter is greater than or equal to 130% of the conversion price of such series of notes on each applicable trading day;

- During the five consecutive business day period immediately after any ten consecutive trading day period (measurement period) in which the trading price per $1,000 principal amount of notes, as determined following a request by a holder or holders, for each trading day of the measurement period was less than 98% of the product of the last reported sale price of our common stock and the conversion rate of such series of notes on each such trading day; or

- Upon the occurrence of specified corporate events, as defined in the related indenture.

Holders may convert all or any portion of their notes at any time, regardless of the foregoing circumstances, on or after March 1, 2028, until the close of business on the second scheduled trading day immediately preceding the maturity date.

Upon conversion, we will pay cash up to the aggregate principal amount of the notes to be converted and pay or deliver cash, shares of our common stock, or a combination of cash and shares of our common stock, at our election, in respect of the remainder, if any, of our conversion obligation in excess of the aggregate principal amount of the notes being converted.

The initial conversion rate for the 2028 Notes is 7.7901 shares of common stock per $1,000 principal amount, which is equivalent to an initial conversion price of approximately $128.37 per share of our common stock. The conversion rate is subject to adjustment upon the occurrence of certain specified events, as defined in the related indenture, but will not be adjusted for any accrued and unpaid interest. In addition, upon the occurrence of a make-whole fundamental change, as defined in the related indenture, we will, in certain circumstances, increase the conversion rate by a number of additional shares of common stock for conversions in connection with the make-whole fundamental change.

As of June 30, 2025, the conditions allowing holders to convert their notes were not met. In accordance with the guidance in ASC Subtopic 470-20, Debt – Debt with Conversion and Other Options, the 2027 Notes, 2028 Notes, and 2029 Notes were accounted for in their entirety as a liability on our balance sheet. The following is a summary of our convertible debt instruments as of June 30, 2025:

(in millions)	Principal Amount	Unamortized Debt Issuance Costs	Net Carrying Amount	Fair Value Amount [(1)]
2027 Notes	**$ 862.5**	**$ (6.4)**	**$ 856.1**	**$ 968.5**
2028 Notes	**900.0**	**(11.2)**	**888.8**	**902.9**
2029 Notes	**862.5**	**(7.8)**	**854.7**	**991.1**

(1) The fair values are categorized in Level 2 of the fair value hierarchy. See Note 13, Fair Value Measurements, for more information on the levels of the fair value hierarchy.

The following table provides a summary of the interest expense recorded for each of the 2027 Notes, 2028 Notes, and 2029 Notes:

	Three Months Ended June 30		Six Months Ended June 30	
(in millions)	2025	2024	2025	2024
2027 Notes				
Contractual interest expense	**$ 9.5**	$ 3.5	**$ 18.9**	$ 3.5
Amortization of debt issuance costs	**0.9**	0.3	**1.7**	0.3
Total interest expense – 2027 Notes	**10.4**	3.8	**20.6**	3.8
2028 Notes				
Contractual interest expense	**1.8**	—	**1.8**	—
Amortization of debt issuance costs	**0.3**	—	**0.3**	—
Total interest expense – 2028 Notes	**$ 2.1**	$ —	**$ 2.1**	$ —
2029 Notes				
Contractual interest expense	**9.5**	3.5	**18.9**	3.5
Amortization of debt issuance costs	**0.5**	0.2	**1.0**	0.2
Total interest expense – 2029 Notes	**$ 10.0**	$ 3.7	**$ 19.9**	$ 3.7

Wisconsin Electric Power Company

In June 2025, WE's $250.0 million of 3.10% Debentures, due June 1, 2025, matured, and outstanding principal and accrued interest were paid with proceeds received from issuing commercial paper.

Minnesota Energy Resources Corporation

In April 2025, MERC issued $50.0 million of 5.20% Senior Notes, due May 1, 2030, and used the net proceeds to repay MERC's $50.0 million of 2.69% Senior Notes that matured on May 1, 2025.

Michigan Gas Utilities Corporation

In April 2025, MGU issued $75.0 million of 5.20% Senior Notes, due May 1, 2030, and used the net proceeds to repay MGU's $60.0 million of 2.69% Senior Notes that matured on May 1, 2025 and intercompany short-term debt to its parent, Integrys.

NOTE 10—LEASES

Obligations Under Operating Leases

In February 2025, WECI closed on its acquisition of a 90% ownership interest in Hardin III, a solar generating facility. Related to its investment in Hardin III, WECI acquired several land leases that commenced in the first quarter of 2025. See Note 2, Acquisitions, for more information on this project.

The land leases acquired related to Hardin III have terms consisting of either 1) an initial term of 25 years with an option for an additional 25-year extension and 2) an initial term of 35 years with an option for a 10-year extension. We expect the optional extensions to be exercised, and, as a result, these land leases are being amortized over the extended terms of the leases. Our total obligation under these land-related operating leases was $29.4 million at June 30, 2025, and was included in other long-term liabilities on our balance sheet. Our operating lease right of use assets were $28.9 million as of June 30, 2025, and were included in other long-term assets on our balance sheet. Our weighted-average discount rate for these land-related operating leases was 6.30%. We used an estimate of the fully collateralized incremental borrowing rates based upon information available for similarly rated companies in determining the present value of lease payments.

Obligations Under Finance Leases

In June 2025, WE and WPS partnered with an unaffiliated utility to acquire and construct High Noon, a utility-scale solar-powered electric generating facility located in Columbia County, Wisconsin. Commercial operation of the project is targeted for 2027. Related to their investment in High Noon, WE and WPS, along with their unaffiliated utility partner, entered into several land leases that commenced in the second quarter of 2025. Each lease has an initial construction term that ends upon achieving commercial operation, then automatically extends for 25 years with an option for an additional 25-year extension. We expect the optional extension to be exercised, and, as a result, these land leases are being amortized over the extended term of the leases. Once High Noon achieves commercial operation, the lease liabilities will be remeasured to reflect the final total acres being leased. We expect to recover the lease payments through rates.

Our total obligation under the High Noon finance leases was $66.6 million at June 30, 2025, and was included in finance lease obligations on our balance sheet. Our finance lease right of use asset related to High Noon was also $66.6 million as of June 30, 2025, and was included in property, plant, and equipment on our balance sheet. Our weighted-average discount rate for the High Noon finance leases was 6.45%. We used an estimate of the fully collateralized incremental borrowing rate based upon information available for similarly rated companies in determining the present value of lease payments. Future minimum lease payments and the corresponding present value of our net minimum lease payments under these land-related leases as of June 30, 2025, were as follows:

(in millions)	Operating Leases	Finance Leases
Six Months Ended December 31, 2025	**$ 0.4**	**$ 2.7**
2026	1.5	1.4
2027	1.5	1.8
2028	1.5	3.6
2029	1.6	3.7
2030	1.6	3.8
Thereafter	110.2	290.8
Total minimum lease payments	118.3	307.8
Less: Interest	(88.9)	(241.2)
Present value of minimum lease payments	29.4	66.6
Less: Short-term lease liabilities	—	—
Long-term lease liabilities	$ 29.4	$ 66.6

NOTE 11—MATERIALS, SUPPLIES, AND INVENTORIES

Our inventories consisted of:

(in millions)	June 30, 2025	December 31, 2024
Materials and supplies	**$ 399.4**	$ 412.5
Natural gas in storage	**209.9**	300.2
Fossil fuel	**93.7**	100.5
Total	**$ 703.0**	$ 813.2

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. For interim periods, the difference between current projected replacement cost and the LIFO cost for quantities of natural gas temporarily withdrawn from storage is recorded as a temporary LIFO liquidation debit or credit. At June 30, 2025, we had a temporary LIFO liquidation credit of $12.8 million recorded within other current liabilities on our balance sheet. Due to seasonality requirements, PGL and NSG expect these interim reductions in LIFO layers to be replenished by year end.

Substantially all other materials and supplies, natural gas in storage, and fossil fuel inventories are recorded using the weighted-average cost method of accounting.

NOTE 12—INCOME TAXES

The provision for income taxes 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:

	Three Months Ended June 30, 2025		Three Months Ended June 30, 2024	
(in millions)	Amount	Effective Tax Rate	Amount	Effective Tax Rate
Statutory federal income tax	**$ 55.6**	**21.0 %**	$ 53.1	21.0 %
State income taxes net of federal tax benefit	**15.2**	**5.8 %**	15.6	6.2 %
PTCs, net	**(40.5)**	**(15.3)%**	(22.2)	(8.8)%
Federal excess deferred tax amortization	**(6.8)**	**(2.6)%**	(4.9)	(1.9)%
AFUDC-Equity	**(2.7)**	**(1.0)%**	(1.8)	(0.7)%
Other, net	**(1.3)**	**(0.5)%**	1.8	0.7 %
Total income tax expense	**$ 19.5**	**7.4 %**	$ 41.6	16.5 %

	Six Months Ended June 30, 2025		Six Months Ended June 30, 2024	
(in millions)	Amount	Effective Tax Rate	Amount	Effective Tax Rate
Statutory federal income tax	**$ 220.4**	**21.0 %**	$ 202.2	21.0 %
State income taxes net of federal tax benefit	**63.7**	**6.1 %**	59.0	6.1 %
PTCs, net	**(160.6)**	**(15.3)%**	(110.2)	(11.4)%
Federal excess deferred tax amortization	**(25.5)**	**(2.5)%**	(20.3)	(2.1)%
AFUDC-Equity	**(11.2)**	**(1.1)%**	(8.1)	(0.9)%
Other, net	**(6.6)**	**(0.6)%**	6.7	0.7 %
Total income tax expense	**$ 80.2**	**7.6 %**	$ 129.3	13.4 %

The effective tax rates for the three and six months ended June 30, 2025 and 2024, differ from the United States statutory federal income tax rate of 21%, primarily due to PTCs generated from ownership interests in renewable generation facilities in our non-utility energy infrastructure and Wisconsin segments and the impact of the protected deferred tax benefits associated with the Tax Legislation, as discussed in more detail below. These items were partially offset by state income taxes.

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 (see federal excess deferred tax amortization lines above).

The IRA contains a tax credit transferability provision that allows us to sell PTCs produced after December 31, 2022, to third parties. Under this transferability provision, we entered into agreements in October 2024 and April 2025 to sell the majority of the PTCs we generate in 2025 and 2026, respectively, to third parties. In May 2025, we entered into an agreement to sell the majority of our remaining unsold PTCs we generated in 2024 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 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 adopted the safe harbor method of accounting for certain of our utilities on our 2023 tax return and plan to adopt the safe harbor method of accounting for our remaining utilities on our 2024 tax return, which increased our deferred tax liabilities.

NOTE 13—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 regional transmission organization.

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:

	June 30, 2025			
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
Derivative assets				
Natural gas contracts	$ 19.2	$ 18.2	$ —	$ 37.4
FTRs and TCRs	—	—	19.0	19.0
Total derivative assets	$ 19.2	$ 18.2	$ 19.0	$ 56.4
Investments held in rabbi trust	$ 37.9	$ —	$ —	$ 37.9
Derivative liabilities				
Natural gas contracts	$ 6.5	$ 9.3	$ —	$ 15.8

(in millions)	December 31, 2024 Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	$ 19.6	$ 13.7	$ —	$ 33.3
FTRs and TCRs	—	—	7.8	7.8
Total derivative assets	$ 19.6	$ 13.7	$ 7.8	$ 41.1
Investments held in rabbi trust	$ 52.1	$ —	$ —	$ 52.1
Derivative liabilities				
Natural gas contracts	$ 7.1	$ 6.8	$ —	$ 13.9

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 and Operating Reserves Markets and the Southwest Power Pool 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. For the three months ended June 30, 2025 and 2024, the net unrealized gains included in earnings related to the investments held at the end of the period were $3.7 million and $1.5 million, respectively. For the six months ended June 30, 2025 and 2024, the net unrealized gains included in earnings related to the investments held at the end of the period were $1.9 million and $5.2 million, respectively.

The following table summarizes the changes to derivatives classified as Level 3 in the fair value hierarchy:

(in millions)	Three Months Ended June 30 2025	2024	Six Months Ended June 30 2025	2024
Balance at the beginning of the period	**$ 3.0**	$ 2.6	**$ 7.8**	$ 7.2
Purchases	**22.5**	25.8	**23.7**	26.8
Net realized and unrealized gains (losses) included in earnings [1]	**0.3**	(0.2)	**—**	(1.0)
Settlements	**(6.8)**	(7.4)	**(12.5)**	(12.2)
Balance at the end of the period	**$ 19.0**	$ 20.8	**$ 19.0**	$ 20.8
Net unrealized losses included in earnings attributable to Level 3 derivatives held at the end of the reporting period [1]	**$ —**	$ (0.2)	**$ —**	$ (0.2)

[1] Amounts relate to FTRs and TCRs included in our non-utility energy infrastructure segment. These net realized and unrealized 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 were not recorded at fair value:

(in millions)	June 30, 2025 Carrying Amount	Fair Value	December 31, 2024 Carrying Amount	Fair Value
Preferred stock of subsidiary	**$ 30.4**	**$ 21.7**	$ 30.4	$ 21.2
Long-term debt, including current portion	**19,360.8**	**18,745.6**	18,907.1	17,840.8

The fair values of our long-term debt and preferred stock are categorized within Level 2 of the fair value hierarchy.

NOTE 14—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 an asset or liability 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.

On our balance sheets, we classify derivative assets and liabilities as current or long-term based on the maturities of the underlying contracts. 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.

	June 30, 2025		December 31, 2024	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Current				
Natural gas contracts	**$ 33.7**	**$ 15.5**	$ 29.2	$ 13.9
FTRs and TCRs	**19.0**	**—**	7.8	—
Total current	**52.7**	**15.5**	37.0	13.9
Long-term				
Natural gas contracts	**3.7**	**0.3**	4.1	—
Total	**$ 56.4**	**$ 15.8**	$ 41.1	$ 13.9

Realized gains and losses on derivatives used in our regulated 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:

	Three Months Ended June 30, 2025		Three Months Ended June 30, 2024	
(in millions)	Volumes	Gains	Volumes	Gains (Losses)
Natural gas contracts	**47.3 Dth**	**$ 6.5**	48.1 Dth	$ (29.8)
FTRs and TCRs	**7.0 MWh**	**3.3**	7.6 MWh	2.0
Total		**$ 9.8**		$ (27.8)

	Six Months Ended June 30, 2025		Six Months Ended June 30, 2024	
(in millions)	Volumes	Gains	Volumes	Gains (Losses)
Natural gas contracts	**108.8 Dth**	**$ 4.6**	115.9 Dth	$ (86.7)
FTRs and TCRs	**14.4 MWh**	**4.8**	15.2 MWh	3.6
Total		**$ 9.4**		$ (83.1)

On our balance sheets, the amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against the fair value amounts recognized for derivative instruments executed with the same counterparty under the same master netting arrangement. At June 30, 2025 and December 31, 2024, we had posted cash collateral of $14.1 million and $16.0 million, respectively. These amounts were recorded on our balance sheets in other current assets. At June 30, 2025 and December 31, 2024, we had also received cash collateral of $6.8 million and $4.2 million, respectively. These amounts were recorded on our balance sheets in other current liabilities.

The following table shows derivative assets and derivative liabilities if derivative instruments by counterparty were presented net on our balance sheets:

	June 30, 2025		December 31, 2024	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Gross amount recognized on the balance sheet	**$ 56.4**	**$ 15.8**	$ 41.1	$ 13.9
Gross amount not offset on the balance sheet	**(16.6)** [1]	**(10.4)**	(11.5) [2]	(7.3)
Net amount	**$ 39.8**	**$ 5.4**	$ 29.6	$ 6.6

(1) Includes cash collateral received of $6.2 million.

(2) Includes cash collateral received of $4.2 million.

Cash Flow Hedges

We 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 related to these swap agreements reclassified from accumulated other comprehensive loss to interest expense during the three and six months ended June 30, 2025 and 2024 were not significant. At June 30, 2025, the amount expected to be reclassified from accumulated other comprehensive loss to interest expense over the next twelve months was also not significant.

NOTE 15—GUARANTEES

The following table shows our outstanding guarantees:

	Total Amounts Committed at June 30, 2025	Expiration		
(in millions)		Less Than 1 Year	1 to 3 Years	Over 3 Years
Standby letters of credit [1]	**$ 177.4**	$ 20.7	$ 30.0	$ 126.7
Surety bonds [2]	**46.5**	44.6	1.9	—
Other guarantees [3]	**10.6**	—	—	10.6
Total guarantees	**$ 234.5**	$ 65.3	$ 31.9	$ 137.3

(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 16—EMPLOYEE BENEFITS

The following tables show the components of net periodic benefit cost (credit) (including amounts capitalized to our balance sheets) for our benefit plans:

	Pension Benefits			
	Three Months Ended June 30		Six Months Ended June 30	
(in millions)	2025	2024	2025	2024
Service cost	**$ 4.8**	$ 5.4	**$ 10.5**	$ 12.1
Interest cost	**29.1**	28.8	**59.4**	58.3
Expected return on plan assets	**(43.6)**	(45.3)	**(87.7)**	(91.1)
Amortization of prior service credit	**(0.1)**	—	**(0.1)**	—
Amortization of net actuarial loss	**9.5**	15.3	**23.1**	29.7
Net periodic benefit cost (credit)	**$ (0.3)**	$ 4.2	**$ 5.2**	$ 9.0

	OPEB Benefits			
	Three Months Ended June 30		Six Months Ended June 30	
(in millions)	2025	2024	2025	2024
Service cost	**$ 2.8**	$ 2.6	**$ 5.6**	$ 5.4
Interest cost	**6.3**	5.7	**12.8**	11.4
Expected return on plan assets	**(13.5)**	(13.1)	**(27.1)**	(26.3)
Amortization of prior service credit	**(1.8)**	(3.4)	**(5.0)**	(6.8)
Amortization of net actuarial gain	**(2.3)**	(1.9)	**(3.7)**	(3.8)
Net periodic benefit credit	**$ (8.5)**	$ (10.1)	**$ (17.4)**	$ (20.1)

During the six months ended June 30, 2025, we made contributions and payments of $6.2 million related to our pension plans and $0.9 million related to our OPEB plans. We expect to make contributions and payments of $5.9 million related to our pension plans and $1.5 million related to our OPEB plans during the remainder of 2025, dependent upon various factors affecting us, including our liquidity position and possible tax law changes.

Effective January 1, 2023, the PSCW approved escrow accounting for pension and OPEB costs. As of June 30, 2025 and December 31, 2024, our balance sheets included regulatory assets of $12.1 million and $24.9 million, respectively, for pension costs and $28.3 million and $38.2 million, respectively, for OPEB costs. In accordance with our December 2024 PSCW rate orders, we began amortizing these regulatory assets in 2025. We continue to utilize escrow accounting for our current pension and OPEB costs. The above tables do not reflect any adjustments for the creation or amortization of these regulatory assets.

NOTE 17—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 June 30, 2025. We had no changes to the carrying amount of goodwill during the six months ended June 30, 2025.

(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 June 30, 2025.

Other Indefinite-Lived Intangible Assets

At both June 30, 2025 and December 31, 2024, we had $29.3 million of indefinite-lived intangible assets, largely consisting of spectrum frequencies. The spectrum frequencies enable our 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.

Finite-Lived Intangible Asset

At June 30, 2025 and December 31, 2024, we had a finite-lived intangible asset with a gross carrying amount of $18.8 million and $13.0 million, respectively, related to a PPA for Maple Flats Solar Energy Center acquired by WECI in November 2024. The PPA will be amortized over a useful life of 15 years and expires in 2039. At June 30, 2025 and December 31, 2024, accumulated amortization related to the intangible asset was not material. This finite-lived intangible asset is included in other long-term assets on our balance sheet. Amortization expense related to the intangible asset was not material for the three and six months ended June 30, 2025. Amortization expense to be recorded as a decrease to operating revenues is expected to be $1.3 million in each of the next five years.

Intangible Liabilities

The intangible liabilities below were all obtained through acquisitions by WECI.

	June 30, 2025			December 31, 2024		
(in millions)	**Gross Carrying Amount**	**Accumulated Amortization**	**Net Carrying Amount**	**Gross Carrying Amount**	**Accumulated Amortization**	**Net Carrying Amount**
PPAs [1]	**$ 751.2**	**$ (147.5)**	**$ 603.7**	$ 679.6	$ (119.3)	$ 560.3
Proxy revenue swap [2]	**7.2**	**(4.6)**	**2.6**	7.2	(4.2)	3.0
Interconnection agreements [3]	**4.7**	**(1.3)**	**3.4**	4.7	(1.2)	3.5
Total intangible liabilities	**$ 763.1**	**$ (153.4)**	**$ 609.7**	$ 691.5	$ (124.7)	$ 566.8

[1] Represents PPAs related to the acquisition of Blooming Grove, Tatanka Ridge, Jayhawk, Thunderhead Wind Energy LLC, Samson I, Sapphire Sky Wind Energy LLC, Delilah I, and Hardin III expiring between 2030 and 2040. The weighted-average remaining useful life of the PPAs is 11 years. See Note 2, Acquisitions, for more information on the acquisition of Hardin III in 2025.

[2] Represents an agreement with a counterparty to swap the market revenue of Upstream Wind Energy LLC's wind generation for fixed quarterly payments over 10 years, which expires in 2029. The remaining useful life of the proxy revenue swap is four years.

[3] Represents interconnection agreements related to the acquisitions of Tatanka Ridge and Bishop Hill Energy III LLC, 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 15 years.

Amortization related to these intangible liabilities for the three and six months ended June 30, 2025, was $14.8 million and $28.7 million, respectively. Amortization related to these intangible liabilities for the three and six months ended June 30, 2024, was $13.4 million and $26.8 million, respectively. Amortization for the next five years, including amounts recorded through June 30, 2025, is estimated to be:

	For the Years Ending December 31				
(in millions)	**2025**	**2026**	**2027**	**2028**	**2029**
Amortization to be recorded as an increase to operating revenues	$ 57.9	$ 59.9	$ 59.9	$ 59.9	$ 59.9
Amortization to be recorded as a decrease to other operation and maintenance	0.2	0.2	0.2	0.2	0.2

NOTE 18—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. The following tables provide a reconciliation of the changes in our investments in ATC and ATC Holdco:

	Three Months Ended June 30, 2025		
(in millions)	ATC	ATC Holdco	Total
Balance at beginning of period	**$ 2,121.6**	**$ 27.4**	**$ 2,149.0**
Add: Earnings from equity method investment	**50.3**	**1.6**	**51.9**
Add: Capital contributions	**45.5**	**—**	**45.5**
Less: Distributions	**39.9**	**6.4**	**46.3**
Balance at end of period	**$ 2,177.5**	**$ 22.6**	**$ 2,200.1**

	Three Months Ended June 30, 2024		
(in millions)	ATC	ATC Holdco	Total
Balance at beginning of period	$ 2,001.6	$ 25.5	$ 2,027.1
Add: Earnings from equity method investment	46.2	0.6	46.8
Add: Capital contributions	18.2	—	18.2
Less: Distributions	36.3	—	36.3
Balance at end of period	$ 2,029.7	$ 26.1	$ 2,055.8

	Six Months Ended June 30, 2025		
(in millions)	ATC	ATC Holdco	Total
Balance at beginning of period	**$ 2,085.1**	**$ 23.8**	**$ 2,108.9**
Add: Earnings from equity method investment	**100.3**	**5.2**	**105.5**
Add: Capital contributions	**87.8**	**—**	**87.8**
Less: Distributions	**95.7**	**6.4**	**102.1**
Balance at end of period	**$ 2,177.5**	**$ 22.6**	**$ 2,200.1**

	Six Months Ended June 30, 2024		
(in millions)	ATC	ATC Holdco	Total
Balance at beginning of period	$ 1,980.8	$ 25.1	$ 2,005.9
Add: Earnings from equity method investment	90.6	1.0	91.6
Add: Capital contributions	30.3	—	30.3
Less: Distributions	72.0	—	72.0
Balance at end of period	$ 2,029.7	$ 26.1	$ 2,055.8

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:

	Three Months Ended June 30		Six Months Ended June 30	
(in millions)	2025	2024	2025	2024
Charges to ATC for services and construction	**$ 5.0**	$ 6.3	**$ 9.5**	$ 11.0
Charges from ATC for network transmission services	**116.7**	103.2	**233.4**	206.5
Refund from ATC related to FERC ROE orders	**0.3**	—	**1.7**	—

Our balance sheets included the following receivables and payables for services provided to or received from ATC:

(in millions)	June 30, 2025	December 31, 2024
Accounts receivable for services provided to ATC	**$ 1.2**	$ 1.4
Accounts payable for services received from ATC	**39.0**	34.4
Amounts due from ATC for transmission infrastructure upgrades [1]	**17.1**	54.5

[1] These transmission infrastructure upgrades were primarily related to the construction of WE's, WPS's, and UMERC's renewable energy projects.

Summarized financial data for ATC is included in the tables below:

	Three Months Ended June 30		Six Months Ended June 30	
(in millions)	2025	2024	2025	2024
Income statement data				
Operating revenues	**$ 241.2**	$ 218.3	**$ 476.1**	$ 430.2
Operating expenses	**117.6**	109.2	**234.3**	214.0
Other expense, net	**42.7**	35.8	**81.8**	71.0
Net income	**$ 80.9**	$ 73.3	**$ 160.0**	$ 145.2

(in millions)	June 30, 2025	December 31, 2024
Balance sheet data		
Current assets	**$ 151.6**	$ 126.6
Noncurrent assets	**7,143.3**	6,792.6
Total assets	**$ 7,294.9**	$ 6,919.2
Current liabilities	**$ 735.8**	$ 482.4
Long-term debt	**3,033.0**	3,083.4
Other noncurrent liabilities	**565.0**	545.0
Members' equity	**2,961.1**	2,808.4
Total liabilities and members' equity	**$ 7,294.9**	$ 6,919.2

NOTE 19—SEGMENT INFORMATION

Our President and Chief Executive Officer, who is our CODM, reviews financial information presented on a segment basis for purposes of making operating decisions and assessing performance. The CODM regularly reviews net income attributed to common shareholders to measure segment profitability and to allocate resources, including assets, to our businesses. Net income attributed to common shareholders best measures our segment profitability as it reflects all revenues and costs, including the impact on our tax provision from tax credits generated through investments in renewable generation facilities.

Our CODM allocates resources such as employees as well as financial and capital resources to our segments during the annual review of budgets and the capital plan. Our CODM also reviews and revises the resources throughout the year during the monthly forecasting process in order to make timely decisions that align with our overall corporate strategy. The CODM uses each segment's net income to evaluate performance by comparing actual results to budgeted and forecasted amounts, as well as the ROE earned for each utility within the various utility segments.

Segments were determined based on a combination of factors, including the regulatory environment of each geographical jurisdiction in which the segment operates, equity investment interests, as well as the revenue streams for the products or services provided to customers through electric, natural gas, and renewable operations. See Note 3, Operating Revenues, for more information on disaggregation of operating revenues, including intercompany eliminations. The accounting policies of the segments are the same as those described in Note 1, Summary of Significant Accounting Policies, in our 2024 Annual Report on Form 10-K.

At June 30, 2025, we reported six segments, which are described below. All of our operations are located within the United States.

- 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. See Note 18, Investment in Transmission Affiliates, for more information on ATC and ATC Holdco.

- 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 holds majority interests in multiple renewable generating facilities.

  See Note 2, Acquisitions, for more information on WECI's recent acquisition of Hardin III.

- The corporate and other segment includes the operations of the WEC Energy Group holding company, the Integrys holding company, the Peoples Energy, LLC holding company, Wispark LLC, Wisvest LLC, Wisconsin Energy Capital Corporation, and WEC Business Services LLC.

The following tables show summarized financial information related to our reportable segments for the three and six months ended June 30, 2025 and 2024:

	Utility Operations								
(in millions)	**Wisconsin**	**Illinois**	**Other States**	**Total Utility Operations**	**Electric Transmission**	**Non-Utility Energy Infrastructure**	**Corporate and Other**	**Reconciling Eliminations**	**WEC Energy Group Consolidated**
Three Months Ended June 30, 2025									
External revenues	$ 1,587.2	$ 270.6	$ 82.3	$ 1,940.1	$ —	$ 69.4	$ —	$ —	$ 2,009.5
Intersegment revenues	—	—	—	—	—	120.0	—	(120.0)	—
Fuel and purchased power	391.8	—	—	391.8	—	—	—	—	391.8
Cost of natural gas sold	128.4	29.5	30.0	187.9	—	1.3	—	(10.5)	178.7
Other operation and maintenance	416.0	112.4	23.9	552.3	—	50.9	(3.1)	(3.9)	596.2
Depreciation and amortization	250.2	64.8	12.3	327.3	—	60.8	5.6	(24.8)	368.9
Property and revenue taxes	44.5	12.8	6.8	64.1	—	4.9	—	—	69.0
Equity in earnings of transmission affiliates	—	—	—	—	51.9	—	—	—	51.9
Other income, net [1]	19.8	2.3	0.1	22.2	—	0.7	11.6	(8.0)	26.5
Interest expense	157.9	22.1	4.7	184.7	4.9	31.5	88.5	(88.8)	220.8
Income tax expense (benefit)	35.5	8.7	1.2	45.4	11.4	(38.9)	1.6	—	19.5
Preferred stock dividends of subsidiary	0.3	—	—	0.3	—	—	—	—	0.3
Net loss attributed to noncontrolling interests	—	—	—	—	—	2.7	—	—	2.7
Net income (loss) attributed to common shareholders	$ 182.4	$ 22.6	$ 3.5	$ 208.5	$ 35.6	$ 82.3	$ (81.0)	$ —	$ 245.4
Other Segment Disclosures									
Three Months Ended June 30, 2025									
Capital expenditures and asset acquisitions	$ 699.5	$ 71.6	$ 37.2	$ 808.3	$ —	$ 17.5	$ 3.6	$ —	$ 829.4
Balance at June 30, 2025									
Equity method investments	16.8	—	—	16.8	2,200.1	—	67.7	—	2,284.6
Total assets [2]	31,314.9	7,989.9	1,624.4	40,929.2	2,201.0	7,812.7	1,234.2	(3,652.8)	48,524.3

[1] Includes amounts that are not material for interest income and other equity earnings from investments other than from transmission affiliates.

[2] Total assets at June 30, 2025 reflect an elimination of $2,629.4 million for all lease activity between We Power and WE.

(in millions)	Utility Operations: Wisconsin	Utility Operations: Illinois	Utility Operations: Other States	Utility Operations: Total Utility Operations	Electric Transmission	Non-Utility Energy Infrastructure	Corporate and Other	Reconciling Eliminations	WEC Energy Group Consolidated
Three Months Ended June 30, 2024									
External revenues	$ 1,368.2	$ 276.8	$ 71.0	$ 1,716.0	$ —	$ 56.0	$ —	$ —	$ 1,772.0
Intersegment revenues	—	—	—	—	—	119.6	—	(119.6)	—
Fuel and purchased power	332.3	—	—	332.3	—	—	—	—	332.3
Cost of natural gas sold	81.7	41.8	23.8	147.3	—	0.9	—	(10.8)	137.4
Other operation and maintenance	389.2	102.6	24.6	516.4	—	25.0	(4.0)	(4.0)	533.4
Depreciation and amortization	228.3	63.7	11.5	303.5	—	49.6	5.4	(21.9)	336.6
Property and revenue taxes	44.9	11.6	6.3	62.8	—	4.7	—	—	67.5
Equity in earnings of transmission affiliates	—	—	—	—	46.8	—	—	—	46.8
Other income, net (1)	32.3	2.3	0.1	34.7	—	0.2	12.5	(6.8)	40.6
Interest expense	157.3	23.5	4.0	184.8	4.9	24.1	76.5	(89.7)	200.6
Income tax expense (benefit)	34.4	10.2	0.3	44.9	10.5	(20.2)	6.4	—	41.6
Preferred stock dividends of subsidiary	0.3	—	—	0.3	—	—	—	—	0.3
Net loss attributed to noncontrolling interests	—	—	—	—	—	1.6	—	—	1.6
Net income (loss) attributed to common shareholders	$ 132.1	$ 25.7	$ 0.6	$ 158.4	$ 31.4	$ 93.3	$ (71.8)	$ —	$ 211.3
Other Segment Disclosures									
Three Months Ended June 30, 2024									
Capital expenditures and asset acquisitions	$ 654.2	$ 93.9	$ 31.5	$ 779.6	$ —	$ 7.4	$ 5.1	$ —	$ 792.1
Balance at June 30, 2024									
Equity method investments	15.0	—	—	15.0	2,055.8	—	67.3	—	2,138.1
Total assets (2)	29,154.2	7,844.7	1,523.5	38,522.4	2,057.7	6,302.9	1,247.3	(3,548.1)	44,582.2

(1) Includes amounts that are not material for interest income and other equity earnings from investments other than from transmission affiliates.

(2) Total assets at June 30, 2024 reflect an elimination of $2,702.9 million for all lease activity between We Power and WE.

Table of Contents

(in millions)	Utility Operations Wisconsin	Illinois	Other States	Total Utility Operations	Electric Transmission	Non-Utility Energy Infrastructure	Corporate and Other	Reconciling Eliminations	WEC Energy Group Consolidated
Six Months Ended June 30, 2025									
External revenues	$ 3,647.1	$ 1,058.9	$ 309.4	$ 5,015.4	$ —	$ 143.6	$ —	$ —	$ 5,159.0
Intersegment revenues	—	—	—	—	—	240.1	—	(240.1)	—
Fuel and purchased power	782.1	—	—	782.1	—	—	—	—	782.1
Cost of natural gas sold	506.9	317.7	147.6	972.2	—	5.8	—	(23.9)	954.1
Other operation and maintenance	831.1	259.3	52.6	1,143.0	—	73.0	(6.3)	(5.5)	1,204.2
Depreciation and amortization	493.8	129.2	24.5	647.5	—	119.0	11.0	(48.7)	728.8
Property and revenue taxes	90.5	33.2	13.3	137.0	—	10.3	0.1	—	147.4
Equity in earnings of transmission affiliates	—	—	—	—	105.5	—	—	—	105.5
Other income, net [(1)]	37.4	4.4	0.2	42.0	—	1.4	16.6	(15.4)	44.6
Interest expense	319.7	45.3	9.0	374.0	9.7	62.1	175.4	(177.4)	443.8
Income tax expense (benefit)	117.5	77.9	16.0	211.4	23.3	(74.5)	(80.0)	—	80.2
Preferred stock dividends of subsidiary	0.6	—	—	0.6	—	—	—	—	0.6
Net loss attributed to noncontrolling interests	—	—	—	—	—	1.7	—	—	1.7
Net income (loss) attributed to common shareholders	$ 542.3	$ 200.7	$ 46.6	$ 789.6	$ 72.5	$ 191.1	$ (83.6)	$ —	$ 969.6
Other Segment Disclosures									
Capital expenditures and asset acquisitions	$ 1,316.4	$ 125.4	$ 55.0	$ 1,496.8	$ —	$ 432.1	$ 7.7	$ —	$ 1,936.6

(1) Includes amounts that are not material for interest income and other equity earnings from investments other than from transmission affiliates.

(in millions)	Utility Operations Wisconsin	Illinois	Other States	Total Utility Operations	Electric Transmission	Non-Utility Energy Infrastructure	Corporate and Other	Reconciling Eliminations	WEC Energy Group Consolidated
Six Months Ended June 30, 2024									
External revenues	$ 3,147.0	$ 942.8	$ 255.6	$ 4,345.4	$ —	$ 106.8	$ —	$ —	$ 4,452.2
Intersegment revenues	—	—	—	—	—	239.7	—	(239.7)	—
Fuel and purchased power	681.5	—	—	681.5	—	—	—	—	681.5
Cost of natural gas sold	383.5	236.5	114.6	734.6	—	5.7	—	(25.0)	715.3
Other operation and maintenance	779.1	209.6	45.2	1,033.9	—	43.2	(7.4)	(5.5)	1,064.2
Depreciation and amortization	452.9	127.2	22.9	603.0	—	98.7	11.0	(42.7)	670.0
Property and revenue taxes	92.2	29.7	12.5	134.4	—	8.5	0.1	—	143.0
Equity in earnings of transmission affiliates	—	—	—	—	91.6	—	—	—	91.6
Other income, net [1]	65.7	4.2	0.1	70.0	—	0.2	28.0	(13.5)	84.7
Interest expense	315.1	48.5	8.0	371.6	9.7	48.2	143.1	(180.0)	392.6
Income tax expense (benefit)	109.3	82.3	13.3	204.9	20.4	(43.6)	(52.4)	—	129.3
Preferred stock dividends of subsidiary	0.6	—	—	0.6	—	—	—	—	0.6
Net loss attributed to noncontrolling interests	—	—	—	—	—	1.6	—	—	1.6
Net income (loss) attributed to common shareholders	$ 398.5	$ 213.2	$ 39.2	$ 650.9	$ 61.5	$ 187.6	$ (66.4)	$ —	$ 833.6
Other Segment Disclosures									
Capital expenditures and asset acquisitions	$ 985.0	$ 169.6	$ 49.6	$ 1,204.2	$ —	$ 24.7	$ 7.7	$ —	$ 1,236.6

[1] Includes amounts that are not material for interest income and other equity earnings from investments other than from transmission affiliates.

NOTE 20—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 sheets:

(in millions)	June 30, 2025	December 31, 2024
Assets		
Other current assets (restricted cash)	**$ 1.4**	$ 1.5
Regulatory assets	**72.2**	76.5
Other long-term assets (restricted cash)	**0.6**	0.6
Liabilities		
Current portion of long-term debt	**9.2**	9.2
Other current liabilities (accrued interest)	**0.1**	0.1
Long-term debt	**71.9**	76.4

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 June 30, 2025 and December 31, 2024, our equity investment in ATC was $2,177.5 million and $2,085.1 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 June 30, 2025 and December 31, 2024, our equity investment in ATC Holdco was $22.6 million and $23.8 million, respectively, which approximates our maximum exposure to loss as a result of our involvement with ATC Holdco.

See Note 18, Investment in Transmission Affiliates, for more information, including any significant assets and liabilities related to ATC and ATC Holdco recorded on our balance sheets.

NOTE 21—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 renewable 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.

Our minimum future commitments related to these purchase obligations as of June 30, 2025, including those of our subsidiaries, were approximately $9.4 billion.

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 sulfur dioxide, NOx, fine particulates, ozone, 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.

Federal Deregulatory Actions

In March 2025, the EPA announced a large-scale deregulatory effort. The EPA announced that, in total, it expects to take 31 deregulatory actions that will likely take multiple years to complete. Of these 31 deregulatory actions, the actions that would apply to us include those impacting the Good Neighbor Rule, MATS, the PM Standard, the GHG Power Plant Rule, the Mandatory Greenhouse Gas Reporting Rule, the ELG, and the CCR Rule. Any EPA actions will require formal rulemaking proceedings and any such actions are likely to be subject to legal challenges. We continue to monitor and evaluate potential risks and benefits to us, depending on the actions ultimately taken.

In July 2025, the EPA proposed to rescind a 2009 declaration that determined that CO_2 and other GHGs endanger public health and welfare. The "endangerment finding" is the legal underpinning of a host of climate regulations under the CAA. The proposal is subject to a review process and public comment and will likely be litigated. We are monitoring the status of the proposal and assessing the potential impact on our business and operations.

Air Quality

Cross State Air Pollution Rule – Good Neighbor Rule

In March 2023, the EPA issued its final Good Neighbor Rule, 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 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.

In February 2024, the Supreme Court heard oral arguments regarding stay applications related to the EPA's Good Neighbor Rule. In June 2024, the Supreme Court granted a stay of the Good Neighbor Rule pending disposition of the applicants' petitions for review at the D.C. Circuit Court of Appeals. After a series of procedural motions and orders, in March 2025, the D.C. Circuit Court of Appeals issued an order removing the case from its active docket and holding the case in abeyance, pending quarterly updates from the parties beginning in July 2025. We will continue to monitor this case as arguments at the D.C. Circuit Court of Appeals move forward.

In November 2024, the EPA issued a Good Neighbor Interim Final Rule that administratively stayed the effectiveness of the Good Neighbor Rule in all states to which it originally applies and ensured implementation of good neighbor obligations previously established to address the 2008 ozone NAAQS while the process works through the courts. We believe we are well positioned to comply with the rule's requirements. See the Federal Deregulatory Actions discussion above for more information regarding potential deregulatory actions regarding this rule.

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. In May 2024, the EPA published a final rule in the Federal Register (the "2024 Final Action") lowering the PM limit from 0.03 lb/MMBtu to 0.01 lb/MMBtu. We believe we are well positioned to comply with the rule's requirements.

In June 2025, the EPA announced a proposed rule to repeal the 2024 Final Action on the basis that it imposed large compliance costs and raised technical feasibility concerns. Currently, the EPA is taking comments on the proposed rule.

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 reconsideration of the 2015 standard. The EPA staff initially issued a draft Policy Assessment in March 2023 that also supported the reconsideration; however, in August 2023, the EPA announced that it was instead restarting its ozone standard evaluation. The EPA released the first two volumes of its Integrated Review Plan in December 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.

The EPA's initial nonattainment area designation was effective August 2018, and the attainment status is evaluated every 3 years thereafter until attainment is achieved. The Milwaukee, Sheboygan, and Chicago, IL-IN-WI nonattainment areas did not meet the marginal attainment deadline of August 2021, so in April 2022 the EPA proposed "moderate" nonattainment status based on the 2015 standard. In October 2022, the EPA published its final reclassifications from "marginal" to "moderate" for these areas, effective November 7, 2022.

The most recent attainment evaluation date was in August 2024. The moderate attainment deadline was not met, so in December 2024 the EPA published a final determination reclassifying the nonattainment areas in Wisconsin to a "serious" classification effective January 16, 2025. This nonattainment status could have a material adverse effect on future permitting activities for our facilities in applicable locations, including additional costs associated with more strenuous emission control requirements or the need to purchase additional emission reduction credits.

Particulate Matter

All counties within our service territories are in attainment with current 2012 standards for fine PM2.5. Under the former presidential administration's policy review, the EPA concluded that the scientific evidence and information from a December 2020 review of the 2012 standards supported revising the level of the annual standard for the PM2.5 NAAQS to below the current level of 12 $\mu g/m^3$, while retaining the 24-hour standard of 35 $\mu g/m^3$. In February 2024, the EPA finalized a rule which lowered the primary (health-based) annual PM2.5 NAAQS to 9 $\mu g/m^3$. The secondary (welfare-based) PM2.5 standard and 24-hour standards (both primary and secondary) remain unchanged. The EPA has until February 2026 to designate areas as attainment and nonattainment with the new standard. The WDNR will need to draft and submit a SIP for the EPA's approval. A designation of nonattainment status could impact future permitting activities for facilities in applicable locations, including the potential need for improved or new air pollution control equipment. With our planned transition from coal-fired plants to natural gas-fired plants and renewable generating facilities, we do not expect this new standard to have a material impact on our units. See the Federal Deregulatory Actions discussion above for more information regarding potential deregulatory actions regarding this rule.

Climate Change

Pursuant to the final GHG Power Plant Rule, there are no applicable standards for coal plants until the end of 2031 and after 2031, the applicable standard is dependent upon the unit's retirement date. Coal-fired units that are planned to refuel to natural gas-fired units must convert to natural gas and no longer retain the capability to burn coal by the end of 2029. For new combined cycle natural gas plants above a 40% capacity factor, the rule is dependent upon the implementation of carbon capture by the end of 2031. For new simple cycle natural gas-fired combustion turbines, there are no applicable limits as long as the capacity factor is less than 20%. Our RICE units in Michigan and the Weston RICE units are not affected under the rule because the rule excludes RICE units that are less than 25 MWs. Numerous parties have challenged the GHG Power Plant Rule through litigation pending in the D.C. Circuit Court of Appeals.

In March 2024, the EPA announced it had removed regulations on existing natural gas combustion turbines from the rule. At that time, the EPA indicated it would work on new rulemaking phases, focusing on CO_2 emissions, as well as NOx and hazardous air pollutants (formaldehyde) emissions. In November 2024, the EPA released the first proposed rule of the three rule "packages" to address NOx emissions from existing combustion turbines. The proposed rule for turbines that operate at a greater than 20% capacity factor will require more stringent NOx limits and control requirements for new, modified, or reconstructed turbines. For turbines that operate at a capacity of 20% or lower, less restrictive standards and the use of combustion controls would apply. We currently believe our existing combined-cycle natural gas facilities would be positioned to comply with the proposed rule if finalized in its current form. See the Federal Deregulatory Actions discussion above for more information regarding potential deregulatory actions regarding this rule.

In June 2025, the EPA announced a proposed rule that contains co-proposals for addressing the GHG Power Plant Rule. The lead proposal would exclude the power sector from the GHG regulation on the grounds that it does not "significantly" contribute to dangerous air pollution. A secondary proposal would eliminate the carbon capture and sequestration/storage and other requirements from the GHG Power Plant Rule. By issuing co-proposals, the EPA is providing public notice of two very different potential regulatory paths. Based on the comments received, the EPA may choose to finalize either approach.

In April 2024, the EPA issued its final Mandatory Greenhouse Gas Reporting Rule, 40 Code of Federal Regulations Part 98, which includes updates to the global warming potentials to determine CO_2 equivalency for threshold reporting and the addition of a new section regarding energy consumption. The revisions will impact the reporting required for our electric generation facilities, LDCs, and underground natural gas storage facilities. In May 2024, the EPA also issued its final rule to amend reporting requirements for petroleum and natural gas systems. Under the final rule, new leak emission factors and reporting requirements for large release events will impact the reporting required for our LDCs and underground natural gas storage facilities. See the Federal Deregulatory Actions discussion above for more information regarding potential deregulatory actions regarding this rule.

Our capital plan includes the retirement of older, fossil-fueled generation, to be replaced with zero-carbon-emitting renewables and reliable, efficient natural gas-fired generation. We have already retired nearly 2,500 MWs of fossil-fueled generation since the beginning of 2018, which includes the retirement of OCPP Units 5 and 6 in May 2024, the 2019 retirement of PIPP, and the 2018 retirements of the Pleasant Prairie power plant, the Pulliam power plant, and the jointly-owned Edgewater Unit 4 generating unit. We expect to retire approximately 1,200 MWs of additional coal-fired generation by the end of 2031, which includes the planned retirements of OCPP Units 7 and 8, the jointly-owned Columbia Units 1 and 2 while investigating conversion of at least one unit to natural gas, and Weston Unit 3. See Note 6, Property, Plant, and Equipment, for more information related to planned power plant retirements. In the third quarter of 2025, we made a decision to reconsider our near-term CO_2 emission reduction goals due to a combination of factors, including tightened energy supply requirements in the Midwest power market and the need to serve our customers with safe, reliable, and affordable energy. However, our long-term goal to achieve net carbon neutral electric generation by 2050 remains intact. We expect to achieve this goal by continuing to make operating refinements, retiring less efficient generating units, and executing our capital plan. As part of our path toward this goal, we have started implementing co-firing with natural gas at the ERGS coal-fired units and plan to begin testing co-firing with natural gas at Weston Unit 4 in 2025. We expect to use coal only as a backup fuel by the end of 2030 and to be in a position to eliminate coal as an energy source by the end of 2032.

We also continue to focus on methane emission reductions by improving and upgrading our natural gas distribution systems, and using RNG throughout our natural gas utility systems. In light of our progress, significant uncertainty surrounding the market for renewable thermal credits, and our desire to focus on long-term GHG emissions-reduction across the enterprise, in the third quarter of 2025, we made a decision to reassess our previous, standalone goal related to methane emissions from natural gas distribution.

Water Quality

Clean Water Act Cooling Water Intake Structure Rule

Revisions to an EPA rule authorized under Section 316(b) of the CWA 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.

Effective in June 2020, the requirements of Section 316(b) 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 final or interim BTA determinations for all generation facilities where Section 316(b) is applicable. The most recent BTA determination was for Weston Units 3 and 4. In accordance with the requirements in the CWA, the WDNR reissued the Weston WPDES permit in June 2024 (effective July 1, 2024) that includes a determination that existing technology (wet cooling towers) installed at the units represents BTA for minimizing adverse environmental impacts. With respect to OCPP Units 7 and 8, we believe the WDNR will reach the same BTA determination decision when the WPDES permit for those units is reissued, which is expected later in 2025.

Steam Electric Effluent Limitation Guidelines

The EPA's 2015 final ELG rule, which took effect in January 2016 (2015 ELG rule), was modified in 2020 (2020 ELG rule), and again in May 2024 with the publication of the Supplemental ELG Rule. These rules establish federal technology-based requirements for several types of power plant wastewaters. The three requirements that affect WE and WPS facilities relate to wastewater discharge limits for BATW, FGD wastewater, and CRL (landfill leachate). Although our coal-fueled facilities were constructed with advanced wastewater treatment technologies that meet many of the discharge limits established by the 2015 rule, facility modifications were still necessary at OCPP, ERGS, and Weston to meet all of the 2015 ELG requirements and the additional ones established by the 2020 ELG rule. Compliance costs associated with the 2015 and 2020 ELG rules required $105 million in capital investment.

The 2024 Supplemental ELG rule established zero discharge requirements for BATW, FGD, and CRL wastewaters at coal-fueled units with no planned retirement date. The Supplemental ELG Rule also kept one existing and created one new “permanent cessation of coal” subcategory. Those electing to cease coal combustion by either retiring or repowering a unit by December 31, 2028 or December 31, 2034 can limit ELG-related capital investments to what was required by either the 2015 or the 2020 ELG Rule, respectively. For units where cessation of coal is planned to occur no later than December 31, 2034, facility owners must complete all 2020 ELG rule required capital investments by December 31, 2025. All WE and WPS coal-fueled units fully meet the 2020 ELG rule requirements. Based on current electrical generation resource planning, we plan to file a NOPP by December 31, 2025 to opt into the "cessation of coal by December 31, 2034" subcategory for both the ERGS and Weston coal-fired facilities. A NOPP also may be filed for the OCPP, Port Washington Generating Station, and VAPP facilities because this ELG rule option will allow the company to qualify for more reasonable requirements to address the CRL provisions at our landfills that served these former coal-fired facilities.

The final Supplemental ELG Rule allows owners of coal-fired units who opted into a cessation of coal subcategory to operate beyond the end of 2028 or 2034, as allowed by either the 2015 or the 2020 ELG Rule, respectively, if needed for reliability concerns (i.e., energy emergencies and reliability must run agreements) as determined by the United States Department of Energy, a public utility commission, or independent system operator.

In November 2024, Edison Electric Institute, on behalf of its members, submitted a petition for reconsideration to the EPA regarding the CRL provisions in the Supplemental ELG Rule in an effort to codify the rule interpretations articulated by the EPA staff during informational conference calls on this issue. We are still awaiting either a rule revision or clear written guidance from the EPA about the Supplemental ELG Rule CRL provisions to determine the applicability and potential compliance costs for inactive/closed landfills.

Numerous parties have challenged the 2024 Supplemental ELG Rule through litigation in *SWEPCO v. U.S. EPA* pending in the U.S. Court of Appeals for the Eighth Circuit. The outcome of this case may affect our compliance plans. This case has been held in abeyance since February 2025. The Supplemental ELG Rule remains in effect during the pendency of the legal challenge.

In June 2025, the EPA announced its intent to update the 2024 Supplemental ELG Rule. See the Federal Deregulatory Actions discussion above for more information regarding potential deregulatory actions regarding this rule.

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:

(in millions)	June 30, 2025	December 31, 2024
Regulatory assets	**$ 527.3**	$ 570.1
Reserves for future environmental remediation	**438.9**	445.8

Coal Combustion Residuals Rule

The EPA finalized a rule for CCR in April 2024 that would apply to landfills, historic fill sites, and projects where CCR was placed at a power plant site. The rule will regulate previously exempt closed landfills.

The final rule, which became effective in November 2024, will have an impact on some of our coal ash landfills, requiring additional remediation that is not currently required under the state programs. The rule is being challenged through litigation pending in the D.C. Circuit Court of Appeals. In June 2025, the D.C. Circuit Court of Appeals granted the EPA's request to extend its ongoing abeyance for an additional 60 days. We expect the cost of the additional remediation would be recovered through future rates. See the Federal Deregulatory Actions discussion above for more information regarding potential deregulatory actions regarding this rule.

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

Joint Ownership Power Plants – Columbia Energy Center and Edgewater Generating Station

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 Unit 4 generating unit was retired in September 2018. WPL started the process to close out this Consent Decree.

NOTE 22—SUPPLEMENTAL CASH FLOW INFORMATION

	Six Months Ended June 30	
(in millions)	**2025**	**2024**
Cash paid for interest, net of amount capitalized	**$ 429.2**	$ 377.7
Cash received for income taxes, net [1] [2]	**(133.2)**	(172.8)
Significant non-cash investing and financing transactions:		
Accounts payable related to construction costs	**153.9**	167.1
Common stock issued for stock-based compensation plans	**3.2**	6.4
Increase (decrease) in receivables related to property damage insurance proceeds	**(1.4)**	2.2
Liabilities accrued for software licensing agreements	**20.7**	—

[1] Cash received for income taxes in 2025 and 2024 includes $113.0 million related to 2024 and 2025 PTCs and $173.0 million related to 2023 and 2024 PTCs, respectively, that were sold to third parties.

[2] Cash received for income taxes in 2025 includes a $25.0 million tax refund received in Wisconsin.

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 to the total of these amounts shown on the statements of cash flows:

(in millions)	June 30, 2025	December 31, 2024
Cash and cash equivalents	**$ 23.0**	$ 9.8
Restricted cash included in other current assets	**11.7**	5.3
Restricted cash included in other long-term assets	**34.5**	27.1
Cash, cash equivalents, and restricted cash	**$ 69.2**	$ 42.2

Our restricted cash primarily 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 WEC Infrastructure Wind Holding I LLC, WEC Infrastructure Wind Holding II LLC, WECI Energy Holding III, and WEPCo Environmental Trust.
- Cash related to WECI's ownership interests in certain renewable generation projects. These projects are required to deposit into an escrow account in order to fund future decommissioning.

NOTE 23—REGULATORY ENVIRONMENT

Wisconsin Electric Power Company

Very Large Customer and Bespoke Resources Tariffs

In March 2025, WE filed an application with the PSCW requesting approval to implement a VLC Tariff and a Bespoke Resources Tariff. Under these proposed inter-connected tariffs, VLCs (new customers using 500 MWs or more, such as large data centers) will have access to reliable power to meet their needs and will directly pay for the electricity they consume, along with the power plants and distribution facilities built to serve them. The proposed tariffs are designed so that the costs associated with these VLCs are not subsidized by or shifted to residential or business customers.

The two new tariffs will work in tandem as VLCs will be required to sign a service agreement and subscribe to a portion of one or more "Bespoke Resources," including renewable generation facilities, battery storage, and natural gas generation units. Under these agreements, if a VLC terminates or downsizes its plans, it will still be required to pay for the Bespoke Resources and dedicated distribution facilities that have been built to support its forecasted load, unless the facilities can be repurposed, subject to PSCW approval. Service agreements under the Bespoke Resources Tariff will be effective for the depreciable life of the resource, except for wind or solar resources which will have a term of 20 years. As proposed, the ROE (10.48%) and equity ratio (57%) will be fixed for the entire term of the agreement, and the revenue and costs recovered through the tariffs will be excluded from future rate case proceedings and earnings sharing mechanisms.

We expect a decision from the PSCW in the second quarter of 2026.

The Peoples Gas Light and Coke Company and North Shore Gas Company

2023 Rate Order

In January 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 returned 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 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 projects to upgrade its natural gas delivery system until the ICC had a proceeding to determine the optimal method for replacing aging natural gas infrastructure and a prudent investment level.

In December 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. The ICC granted PGL and NSG a limited-scope rehearing focused exclusively on the authorized spending for the completion of projects to upgrade PGL's natural gas delivery system that started in 2023 and emergency repairs needed to ensure the safety and reliability of the delivery system. On May 30, 2024, the ICC issued a written order on the rehearing. The order approved $28.5 million of additional spending for emergency work, representing a $1.6 million increase to PGL's annual revenue requirement.

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 during the fourth quarter of 2023. This amount included $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.

On June 7, 2024, PGL and NSG filed a petition with the Illinois Appellate Court for review of the November 16, 2023 and May 30, 2024 orders. The appeal includes the ICC's $237.9 million combined disallowance of capital costs at PGL and NSG discussed above, along with the $116.0 million disallowance of capital investments needed to meet safety and reliability requirements of PGL's natural gas delivery system. Although the ICC ordered PGL to complete safety and reliability work in 2024, it denied the recovery of these costs in the current rates.

In accordance with the November 16, 2023 rate order, the ICC initiated a proceeding in January 2024 to determine the optimal method and a prudent investment level for replacing aging natural gas infrastructure. On February 20, 2025, the ICC issued an order setting expectations for PGL's prospective operations. The ICC directed us to focus on replacing all cast and ductile iron pipe that has a diameter under 36 inches by January 1, 2035. The ICC also indicated that failure to comply with this directive could subject us to civil penalties under Illinois statute. PGL will replace this cast and ductile iron pipe through its PRP. Costs incurred under the PRP will be evaluated for prudency by the ICC in future rate cases. In addition, the program will be overseen by a safety monitor hired by the ICC. We are evaluating the impact of this order on our operations and capital plan.

Uncollectible Expense Adjustment Rider

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 required a $15.4 million and $0.7 million refund to ratepayers at PGL and NSG, respectively. These amounts were refunded over a period of nine months, which began on September 1, 2023. In July 2023, PGL and NSG petitioned the Illinois Appellate Court for review of the ICC order. In November 2024, the Illinois Appellate Court issued an opinion affirming the ICC order and the related disallowance. PGL and NSG subsequently petitioned the Illinois Supreme Court seeking review and reversal of the May 2023 order; however, their petition was denied in March 2025.

As of June 30, 2025, there can be no assurance that all costs incurred under the UEA rider during the open reconciliation years, which include 2019 through 2024, will be deemed recoverable by the ICC. The combined annual costs of PGL and NSG included in the rider, which reflect uncollectible write-offs in excess of what is recovered in base rates, have ranged from $10 million to $40 million during these open reconciliation years. Disallowances by the ICC, if any, could be material and have a material adverse impact on our results of operations.

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 August 2024, the ICC issued a final order on PGL's 2016 annual reconciliation, which included a disallowance of $14.8 million of certain capital costs. PGL recorded a pre-tax charge to income of $25.3 million during the third quarter of 2024 related to the disallowance and the previously recognized return on these investments. The charge was recorded on the income statement as a $12.9 million reduction in revenues for the amounts previously collected from customers, a $12.1 million increase to operation and maintenance expense for the impairment of PGL's property, plant, and equipment, and a $0.3 million increase to interest expense related to the amounts due to customers. In October 2024, PGL filed a petition with the Illinois Appellate Court for review of the ICC's August order.

PGL's QIP reconciliations from 2017 through 2023 are still pending. In July 2025, ICC staff and certain intervenors filed testimony with the ICC recommending significant disallowances in the 2017 QIP reconciliation proceeding. We believe that all costs were prudently incurred, but cannot predict the ultimate outcome of this matter. There is no statutory deadline by which the ICC is required to issue an order in this proceeding. The aggregate capital costs included in the rider during the open reconciliation years, along with any previously recognized return on these investments, totaled approximately $2.9 billion as of June 30, 2025. There can be no assurance that all of these costs and the previously recognized returns 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.

Upper Michigan Energy Resources Corporation

Amended Renewable Energy Plan

In accordance with Michigan Public Act 235, UMERC filed an AREP with the MPSC in February 2025. UMERC's AREP addresses its compliance with the Act 235 renewable portfolio standards and its proposal to recover the projected compliance costs through an incremental renewable energy surcharge. The projected compliance costs include the purchase of Michigan-sourced renewable energy credits and the revenue requirements for Renegade (see discussion below) and any other incremental renewable generation resources required to meet the Act 235 renewable portfolio standards.

UMERC's AREP includes its previously approved investment in Renegade, a 100 MW utility-scale solar-powered electric generating facility that will be located in Delta and Marquette counties, Michigan. Construction of Renegade is expected to be completed in February 2026, and the cost of this project is estimated to be approximately $226 million. UMERC expects to be authorized to begin recovering the annual revenue requirement of Renegade through the proposed renewable energy surcharge in January 2026.

The MPSC's approval of the AREP and the proposed renewable energy surcharge is still pending.

NOTE 24—NEW ACCOUNTING PRONOUNCEMENTS

Disaggregation of Income Statement Expenses

In November 2024, the FASB issued ASU No. 2024-03, Income Statement-Reporting Comprehensive Income-Expense Disaggregation Disclosures (Subtopic 220-40) Disaggregation of Income Statement Expenses. The amendments require disclosure of certain costs and expenses in the notes to financial statements, which are disaggregated from relevant expense captions on the income statement. The amendments also require additional qualitative disclosures of the amounts remaining in relevant expense captions that are not separately disaggregated quantitatively. Finally, the amendments require disclosure of the total amount of selling expenses and, in annual reporting periods, an entity's definition of selling expenses. The amendments are effective for annual periods beginning after December 15, 2026, and interim periods beginning after December 15, 2027, with early adoption permitted. We plan to adopt these amendments beginning with our fiscal year ending on December 31, 2027, and are currently evaluating the impact this guidance may have on our financial statements and related disclosures.

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.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

CORPORATE DEVELOPMENTS

The following discussion should be read in conjunction with the accompanying unaudited financial statements and related notes and our 2024 Annual Report on Form 10-K.

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 the 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 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 capital plan includes the retirement of older, fossil-fueled generation, to be replaced with zero-carbon-emitting renewables and reliable, efficient natural gas-fired generation. The retirements are intended to address compliance with the EPA Clean Air rules as well as 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 reliable, efficient natural gas generation should better balance our supply with our demand, while helping to address compliance and maintaining reliable, affordable energy for our customers.

In the third quarter of 2025, we made a decision to reconsider our near-term CO_2 emission reduction goals due to a combination of factors, including tightened energy supply requirements in the Midwest power market and the need to serve our customers with safe, reliable, and affordable energy. However, our long-term goal to achieve net carbon neutral electric generation by 2050 remains intact. We expect to achieve this goal by continuing to make operating refinements, retiring less efficient generating units, and executing our capital plan. As part of our path toward this goal, we have started implementing co-firing with natural gas at the ERGS coal-fired units and plan to begin testing co-firing with natural gas at Weston Unit 4 in 2025. We expect to use coal only as a backup fuel by the end of 2030 and to be in a position to eliminate coal as an energy source by the end of 2032.

We have already retired nearly 2,500 MWs of fossil-fueled generation since the beginning of 2018, which includes the retirement of OCPP Units 5 and 6 in May 2024, the 2019 retirement of the PIPP, and the 2018 retirements of the Pleasant Prairie power plant, the Pulliam power plant, and the jointly-owned Edgewater Unit 4 generating unit. We expect to retire approximately 1,200 MWs of additional coal-fired generation by the end of 2031, which includes the planned retirements of OCPP Units 7 and 8, the jointly-owned Columbia Units 1 and 2, and Weston Unit 3. See Note 6, 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 $9.1 billion from 2025-2029 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 investments:

- 2,900 MWs of utility-scale solar;
- 900 MWs of wind; and
- 565 MWs of battery storage.

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

- 1,100 MWs of combustion turbines to be constructed at our OCPP site (we plan on constructing a new natural gas lateral pipeline to support this generation); with
- An additional 675 MWs of combustion turbines planned; and
- 128 MWs of RICE natural gas-fueled generation to be constructed in Kenosha County; with
- An additional 114 MWs of RICE natural gas-fueled generation planned.

For more details on the projects discussed above, 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 30 Solar Now projects, 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. WE has signed up one customer under this program for 4 MWs of generation capacity. 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. Under this program, WE and WPS have collectively signed up ten customers, for a total of approximately 52 MWs of generation capacity.

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. We proposed modifications to these pilot programs, which were approved by the PSCW and implemented on January 1, 2025. 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 focus on methane emission reductions by improving and upgrading our natural gas distribution systems, and using RNG throughout our natural gas utility systems. In 2022, we received approval from the PSCW for our RNG pilots and in 2023, we began transporting the output of local dairy farms onto our natural gas distribution systems in Wisconsin. The RNG supplied is expected to directly replace higher-emission methane from natural gas that would have entered our pipes. We currently have contracts in place for 2.1 Bcf of RNG. In light of our progress, significant uncertainty surrounding the market for renewable thermal credits, and our desire to focus on long-term GHG emissions-reduction across the enterprise, in the third quarter of 2025, we made a decision to reassess our previous, standalone goal related to methane emissions from natural gas distribution.

In December 2023, we started a pilot program with Electric Power Research Institute and CMBlu Energy, a Germany-based designer and manufacturer of an organic solid flow battery, to test this new form of long-duration energy storage on the U.S. electric grid at our VAPP. 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 pilot activities to continue throughout 2025.

Reliability

We have made significant reliability-related investments in recent years, and in accordance with our capital 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.

- On July 17, 2025, the PSCW verbally approved WE's request to construct an LNG facility with a storage capacity of two Bcf, which will be located on the OCPP site. In addition, the construction of additional LNG facilities in Wisconsin has been proposed as part of our capital plan and would provide another approximately four Bcf of natural gas supply. The LNG facilities are expected to reduce the likelihood of constraints on our natural gas distribution system during the highest demand days of winter.

- 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 these projects until the ICC completed a proceeding to determine the optimal method for replacing aging natural gas infrastructure and a prudent investment level. The ICC subsequently granted PGL a limited-scope rehearing related to the completion of the projects that started in 2023 and emergency repairs needed to ensure the safety and reliability of the delivery system. In May 2024, the ICC issued a written order on the rehearing, approving $28.5 million of additional spending for this emergency work.

  In February 2025, the ICC issued an order setting expectations for PGL's prospective replacement of its aging natural gas infrastructure. The ICC directed us to focus on replacing all cast and ductile iron pipe that has a diameter of less than 36 inches by January 1, 2035. PGL will replace this cast and ductile iron pipe through its PRP. For more information, see Note 23, Regulatory Environment, and Factors Affecting Results, Liquidity, and Capital Resources - Regulatory, Legislative, and Legal Matters - Illinois Proceedings.

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

We expect to spend approximately $4.5 billion from 2025 to 2029 on reliability related to electric distribution 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 our capital 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 improving our business processes to find the best and most efficient processes possible. We expect these efforts to continue to drive operational efficiency and to put us in a position to effectively support plans for future growth.

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.

Our planned investment focus from 2025 to 2029 is in our regulated utilities and our investment in ATC. We expect total capital expenditures for our regulated utility businesses to be approximately $24.4 billion from 2025 to 2029. In addition, we currently forecast that our share of ATC's projected capital expenditures over the next five years will be approximately $3.2 billion. In February 2025, we invested $406.1 million in our non-utility energy infrastructure business with the acquisition of Hardin III. Specific projects included in the $28.0 billion capital plan are discussed in more detail below under Liquidity and Capital Resources – Cash Requirements – Significant Capital Projects. Also, see Note 2, Acquisitions, for additional information on the acquisition of Hardin III.

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

THREE MONTHS ENDED JUNE 30, 2025

Consolidated Earnings

The following table compares our consolidated results for the second quarter of 2025 with the second quarter of 2024, including favorable or better, "B", and unfavorable or worse, "W", variances:

	Three Months Ended June 30		
(in millions, except per share data)	**2025**	**2024**	**B (W)**
Wisconsin	**$ 182.4**	$ 132.1	$ 50.3
Illinois	**22.6**	25.7	(3.1)
Other states	**3.5**	0.6	2.9
Electric transmission	**35.6**	31.4	4.2
Non-utility energy infrastructure	**82.3**	93.3	(11.0)
Corporate and other	**(81.0)**	(71.8)	(9.2)
Net income attributed to common shareholders	**$ 245.4**	$ 211.3	$ 34.1
Diluted EPS	**$ 0.76**	$ 0.67	$ 0.09

Earnings increased $34.1 million during the second quarter of 2025, compared with the same quarter in 2024. The $34.1 million increase in earnings was driven by a $50.3 million increase in net income attributed to common shareholders at the Wisconsin segment, primarily due to higher margins from the impact of the Wisconsin rate orders approved by the PSCW, effective January 1, 2025, and higher retail sales volumes. See Note 26, Regulatory Environment, in our 2024 Annual Report on Form 10-K, for more information on the 2025 rate orders. These positive impacts were partially offset by higher operating expenses, primarily due to increases in depreciation and amortization expense, transmission expense, and regulatory amortizations.

This increase in earnings was partially offset by:

- An $11.0 million decrease in net income attributed to common shareholders at the non-utility energy infrastructure segment, driven by lower operating income at WECI. An increase in PTCs from our non-utility renewable generating facilities partially offset the lower operating income.

- A $9.2 million increase in the net loss attributed to common shareholders at the corporate and other segment, driven by higher interest expense primarily due to the impact of long-term debt issuances at WEC Energy Group.

Non-GAAP Financial Measures

The discussions below address the contribution of each of our utility segments to net income attributed to common shareholders. The discussions include financial information prepared in accordance with GAAP, as well as utility margin, which is not a measure of financial performance under GAAP. Utility margin (operating revenues less fuel and purchased power costs and cost of natural gas sold) is a non-GAAP financial measure because it excludes certain operation and maintenance expenses applicable to revenues, as well as depreciation and amortization and property and revenue taxes.

We believe that utility margin provides 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 utility margin internally when assessing the operating performance of our utility segments as these measures exclude the majority of revenue fluctuations caused by changes in these expenses. Similarly, the presentation of utility margin herein is intended to provide supplemental information for investors regarding our operating performance.

Our utility margin may not be comparable to similar measures presented by other companies. Furthermore, this measure is not intended to replace gross margin as determined in accordance with GAAP as an indicator of operating performance. Each of our three utility segment discussions below include a table that provides the calculation of both gross margin as determined in accordance with GAAP and utility margin, as well as a reconciliation between the two measures.

Wisconsin Segment Contribution to Net Income Attributed to Common Shareholders

The Wisconsin segment's contribution to net income attributed to common shareholders was $182.4 million during the second quarter of 2025, representing a $50.3 million, or 38.1%, increase over the same quarter in 2024. The increase in earnings was driven by higher margins from the impact of the Wisconsin rate orders approved by the PSCW, effective January 1, 2025, and higher retail sales volumes. See Note 26, Regulatory Environment, in our 2024 Annual Report on Form 10-K, for more information on the 2025 rate orders. These positive impacts were partially offset by higher operating expenses, primarily due to increases in depreciation and amortization expense, transmission expense, and regulatory amortizations.

	Three Months Ended June 30		
(in millions)	**2025**	**2024**	**B (W)**
Operating revenues	**$ 1,587.2**	$ 1,368.2	$ 219.0
Operating expenses			
Cost of sales [(1)]	**520.2**	414.0	(106.2)
Other operation and maintenance	**416.0**	389.2	(26.8)
Depreciation and amortization	**250.2**	228.3	(21.9)
Property and revenue taxes	**44.5**	44.9	0.4
Operating income	**356.3**	291.8	64.5
Other income, net	**19.8**	32.3	(12.5)
Interest expense	**157.9**	157.3	(0.6)
Income before income taxes	**218.2**	166.8	51.4
Income tax expense	**35.5**	34.4	(1.1)
Preferred stock dividends of subsidiary	**0.3**	0.3	—
Net income attributed to common shareholders	**$ 182.4**	$ 132.1	$ 50.3

(1) Cost of sales includes fuel and purchased power and cost of natural gas sold.

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

	Three Months Ended June 30		
(in millions)	**2025**	**2024**	**B (W)**
Operation and maintenance not included in line items below	**$ 177.1**	$ 169.5	$ (7.6)
Transmission [1]	**147.0**	135.7	(11.3)
Regulatory amortizations and other pass through expenses [2]	**61.2**	51.7	(9.5)
We Power [3]	**32.5**	33.1	0.6
Earnings sharing mechanisms	**(1.8)**	(0.8)	1.0
Total other operation and maintenance	**$ 416.0**	$ 389.2	$ (26.8)

(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 the second quarter of 2025 and 2024, $159.9 million and $140.0 million, respectively, of costs were billed to our electric utilities by transmission providers.

(2) Regulatory amortizations and other pass through expenses are substantially offset in margins and therefore do not have a significant impact on net income.

(3) Represents costs associated with the We Power generation units, including operating and maintenance costs recognized by WE. During the second quarter of 2025 and 2024, $32.9 million and $29.3 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.

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

	Three Months Ended June 30		
	MWh *(in thousands)*		
Electric Sales Volumes	**2025**	**2024**	**B (W)**
Customer Class			
Residential	**2,564.5**	2,522.9	41.6
Small commercial and industrial [1]	**3,138.7**	3,118.9	19.8
Large commercial and industrial [1]	**3,003.1**	2,982.4	20.7
Other	**24.9**	26.5	(1.6)
Total retail [1]	**8,731.2**	8,650.7	80.5
Wholesale	**417.7**	402.0	15.7
Resale	**1,507.1**	1,322.3	184.8
Total sales in MWh [1]	**10,656.0**	10,375.0	281.0

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

	Three Months Ended June 30		
	Therms *(in millions)*		
Natural Gas Sales Volumes	**2025**	**2024**	**B (W)**
Customer Class			
Residential	**155.3**	129.8	25.5
Commercial and industrial	**109.1**	91.4	17.7
Total retail	**264.4**	221.2	43.2
Transportation	**303.1**	294.0	9.1
Total sales in therms	**567.5**	515.2	52.3

Weather	Three Months Ended June 30 Degree Days 2025	2024	B (W)
WE and WG [1]			
Heating (874 Normal)	**1,013**	631	60.5 %
Cooling (182 Normal)	**176**	202	(12.9)%
WPS [2]			
Heating (919 Normal)	**888**	760	16.8 %
Cooling (157 Normal)	**160**	142	12.7 %
UMERC [3]			
Heating (1,164 Normal)	**1,166**	1,088	7.2 %
Cooling (88 Normal)	**102**	57	78.9 %

[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.

Gross Margin GAAP and Utility Margin Non-GAAP

The following table summarizes our Wisconsin segment gross margin (GAAP) and reconciles gross margin (GAAP) to utility margin (non-GAAP). See "Non-GAAP Financial Measures" above for additional information regarding gross margin (GAAP) and utility margin (non-GAAP).

(in millions)	Three Months Ended June 30 2025	2024	B (W)
Electric revenues	**$ 1,308.0**	$ 1,151.0	$ 157.0
Natural gas revenues	**279.2**	217.2	62.0
Operating revenues	**1,587.2**	1,368.2	219.0
Operating expenses			
Fuel and purchased power	**(391.8)**	(332.3)	(59.5)
Cost of natural gas sold	**(128.4)**	(81.7)	(46.7)
Other operation and maintenance [1]	**(310.1)**	(289.8)	(20.3)
Depreciation and amortization	**(250.2)**	(228.3)	(21.9)
Property and revenue taxes	**(44.5)**	(44.9)	0.4
Gross margin (GAAP)	**462.2**	391.2	71.0
Other operation and maintenance [1]	**310.1**	289.8	20.3
Depreciation and amortization	**250.2**	228.3	21.9
Property and revenue taxes	**44.5**	44.9	(0.4)
Utility margin (non-GAAP)	**$ 1,067.0**	$ 954.2	$ 112.8

[1] Operating and maintenance expenses deemed to be directly attributable to our revenue-producing activities include plant operating and maintenance expenses related to our generating units; costs associated with the We Power generating units; and transmission, distribution and customer service expenses. These expenses are included in the above table to calculate gross margin as defined under GAAP.

Gross margin (GAAP) at the Wisconsin segment increased $71.0 million during the second quarter of 2025, compared with the same quarter in 2024, and utility margin (non-GAAP) increased $112.8 million during the second quarter of 2025, compared with the same quarter in 2024. Both measures were driven by:

- An $87.9 million increase in margins driven by the impact of the Wisconsin rate orders approved by the PSCW, effective January 1, 2025. See Note 26, Regulatory Environment, in our 2024 Annual Report on Form 10-K, for more information on the 2025 rate orders.

- A $19.6 million increase in margins related to higher retail sales volumes, driven by the impact of colder spring weather during the second quarter of 2025, compared with the same quarter in 2024. As measured by heating degree days, the second quarter of 2025 was 60.5% and 16.8% colder than the same quarter in 2024 in the Milwaukee area and Green Bay area, respectively.

- A $3.7 million quarter-over-quarter 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 above or below the 2% is generally deferred for either future recovery from or refund to customers.

Additionally, the smaller increase in gross margin (GAAP) as compared with the increase in utility margin (non-GAAP), was driven by the following items that are further described in Other Operating Expenses below:

- A $21.9 million increase in depreciation and amortization expense;

- An $11.3 million increase in transmission expense; and

- A $6.3 million increase in electric and natural gas distribution expenses.

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

Other operating expenses at the Wisconsin segment increased $48.3 million during the second quarter of 2025, compared with the same quarter in 2024. The significant factors impacting the increase in other operating expenses were:

- A $21.9 million increase in depreciation and amortization expense, driven by assets being placed into service as we continue to execute on our capital plan.

- An $11.3 million increase in transmission expense as approved by the PSCW in our Wisconsin rate orders, effective January 1, 2025. See the notes under the other operation and maintenance table above for more information.

- A $9.5 million increase in regulatory amortizations and other pass through expenses, as discussed in the notes under the other operation and maintenance table above.

- A $6.3 million increase in electric and natural gas distribution expenses, driven by higher costs to maintain the distribution systems during the second quarter of 2025, compared with the same quarter in 2024.

Other Income, Net

Other income, net at the Wisconsin segment decreased $12.5 million during the second quarter of 2025, compared with the same quarter in 2024, driven by a $21.5 million negative impact from the non-service components of our net periodic pension and OPEB costs. See Note 16, Employee Benefits, for more information on our benefit costs. This decrease was partially offset by an $8.9 million positive impact from higher AFUDC-Equity due to continued capital investment.

Interest Expense

Interest expense at the Wisconsin segment increased $0.6 million during the second quarter of 2025, compared with the same quarter in 2024, driven by the impact of WE, WPS, and WG issuing long-term debt in 2024. Partially offsetting the increase was lower average short-term debt balances, lower short-term debt interest rates, and higher AFUDC-Debt due to continued capital investment.

Income Tax Expense

Income tax expense at the Wisconsin segment increased $1.1 million during the second quarter of 2025, compared with the same quarter in 2024, driven by higher pre-tax income. Partially offsetting this increase was an increase in PTCs, an increase in income tax benefits associated with AFUDC-Equity, driven by continued capital investment, and the increased benefit from the flow through of tax repairs in connection with the Wisconsin rate orders approved by the PSCW, effective January 1, 2025.

Illinois Segment Contribution to Net Income Attributed to Common Shareholders

The Illinois segment's contribution to net income attributed to common shareholders was $22.6 million during the second quarter of 2025, representing a $3.1 million, or 12.1%, decrease in earnings over the same quarter in 2024. The lower earnings were driven by higher operating expenses, largely due to an increase in costs associated with maintenance at the Manlove Gas Storage Field.

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.

	Three Months Ended June 30		
(in millions)	2025	2024	B (W)
Operating revenues	**$ 270.6**	$ 276.8	$ (6.2)
Operating expenses			
Cost of natural gas sold	**29.5**	41.8	12.3
Other operation and maintenance	**112.4**	102.6	(9.8)
Depreciation and amortization	**64.8**	63.7	(1.1)
Property and revenue taxes	**12.8**	11.6	(1.2)
Operating income	**51.1**	57.1	(6.0)
Other income, net	**2.3**	2.3	—
Interest expense	**22.1**	23.5	1.4
Income before income taxes	**31.3**	35.9	(4.6)
Income tax expense	**8.7**	10.2	1.5
Net income attributed to common shareholders	**$ 22.6**	$ 25.7	$ (3.1)

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

	Three Months Ended June 30		
(in millions)	2025	2024	B (W)
Operation and maintenance not included in the line items below	**$ 78.4**	$ 75.3	$ (3.1)
Riders [(1)]	**33.3**	26.6	(6.7)
Regulatory amortizations [(1)]	**0.7**	0.7	—
Total other operation and maintenance	**$ 112.4**	$ 102.6	$ (9.8)

[(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	Three Months Ended June 30 Therms *(in millions)* 2025	2024	B (W)
Customer Class			
Residential	**122.6**	104.3	18.3
Commercial and industrial	**41.2**	37.8	3.4
Total retail	**163.8**	142.1	21.7
Transportation	**132.6**	118.5	14.1
Total sales in therms	**296.4**	260.6	35.8

Weather [1]	Three Months Ended June 30 Degree Days 2025	2024	B (W)
Heating (697 Normal)	**698**	450	55.1 %

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

Gross Margin GAAP and Utility Margin Non-GAAP

The following table summarizes our Illinois segment gross margin (GAAP) and reconciles gross margin (GAAP) to utility margin (non-GAAP). See "Non-GAAP Financial Measures" above for additional information regarding gross margin (GAAP) and utility margin (non-GAAP).

(in millions)	Three Months Ended June 30 2025	2024	B (W)
Operating revenues	**$ 270.6**	$ 276.8	$ (6.2)
Operating expenses			
Cost of natural gas sold	**(29.5)**	(41.8)	12.3
Other operation and maintenance [1]	**(63.3)**	(56.1)	(7.2)
Depreciation and amortization	**(64.8)**	(63.7)	(1.1)
Property and revenue taxes	**(12.8)**	(11.6)	(1.2)
Gross margin (GAAP)	**100.2**	103.6	(3.4)
Other operation and maintenance [1]	**63.3**	56.1	7.2
Depreciation and amortization	**64.8**	63.7	1.1
Property and revenue taxes	**12.8**	11.6	1.2
Utility margin (non-GAAP)	**$ 241.1**	$ 235.0	$ 6.1

[1] Operating and maintenance expenses deemed to be directly attributable to our revenue-producing activities include distribution and customer service expenses. These expenses are included in the above table to calculate gross margin as defined under GAAP.

Gross margin (GAAP) at the Illinois segment decreased $3.4 million during the second quarter of 2025, compared with the same quarter in 2024, and utility margin (non-GAAP) increased $6.1 million during the second quarter of 2025, compared with the same quarter in 2024. Both measures were impacted by a $6.7 million increase in revenues associated with certain riders that are offset in other operation and maintenance and therefore do not have a significant impact on net income.

Additionally, the decrease in gross margin (GAAP) as compared with the increase in utility margin (non-GAAP), was driven by the following items that are further described in Other Operating Expenses below:

- A $4.8 million increase in costs associated with maintenance at the Manlove Gas Storage Field;
- A $1.5 million increase in natural gas distribution and maintenance costs;

- A $1.2 million increase in property and revenue taxes; and

- A $1.1 million increase in depreciation and amortization.

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

Other operating expenses at the Illinois segment increased $5.4 million, net of the $6.7 million impact of the riders referenced in the table above, during the second quarter of 2025, compared with the same quarter in 2024. The significant factors impacting the increase in other operating expenses were:

- A $4.8 million increase in costs associated with maintenance at the Manlove Gas Storage Field.

- A $1.5 million increase in natural gas distribution and maintenance costs, primarily related to maintaining the natural gas infrastructure.

- A $1.2 million increase in property and revenue taxes, driven by higher use taxes.

- A $1.1 million increase in depreciation and amortization, driven by assets being placed into service as we continue to execute on our capital plan.

These increases in operating expenses were partially offset by a $2.2 million pre-tax gain on the renegotiation of a lease contract during the second quarter of 2025.

Interest Expense

Interest expense at the Illinois segment decreased $1.4 million during the second quarter of 2025, compared with the same quarter in 2024, due to lower average short-term debt balances, lower short-term debt interest rates, and the impact of a series of PGL's first mortgage bonds maturing in November 2024.

Income Tax Expense

Income tax expense at the Illinois segment decreased $1.5 million during the second quarter of 2025, compared with the same quarter in 2024, driven by a decrease in pre-tax income.

Other States Segment Contribution to Net Income Attributed to Common Shareholders

The other states segment's net income attributed to common shareholders was $3.5 million during the second quarter of 2025, representing a $2.9 million, or 483.3%, increase over the same quarter in 2024. The increase was driven by higher margins related to positive impacts from MGU's approved rate increase that was effective January 1, 2025 and MERC's rate increase that was effective March 1, 2024.

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

	Three Months Ended June 30		
(in millions)	2025	2024	B (W)
Operating revenues	**$ 82.3**	$ 71.0	$ 11.3
Operating expenses			
Cost of natural gas sold	**30.0**	23.8	(6.2)
Other operation and maintenance	**23.9**	24.6	0.7
Depreciation and amortization	**12.3**	11.5	(0.8)
Property and revenue taxes	**6.8**	6.3	(0.5)
Operating income	**9.3**	4.8	4.5
Other income, net	**0.1**	0.1	—
Interest expense	**4.7**	4.0	(0.7)
Income before income taxes	**4.7**	0.9	3.8
Income tax expense	**1.2**	0.3	(0.9)
Net income attributed to common shareholders	**$ 3.5**	$ 0.6	$ 2.9

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

	Three Months Ended June 30		
(in millions)	2025	2024	B (W)
Operation and maintenance not included in line item below	**$ 19.2**	$ 18.9	$ (0.3)
Regulatory amortizations and other pass through expenses [1]	**4.7**	5.7	1.0
Total other operation and maintenance	**$ 23.9**	$ 24.6	$ 0.7

[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:

	Three Months Ended June 30		
	Therms *(in millions)*		
Natural Gas Sales Volumes	2025	2024	B (W)
Customer Class			
Residential	**42.1**	34.9	7.2
Commercial and industrial	**26.2**	25.9	0.3
Total retail	**68.3**	60.8	7.5
Transportation	**168.3**	187.7	(19.4)
Total sales in therms	**236.6**	248.5	(11.9)

	Three Months Ended June 30		
	Degree Days		
Weather [1]	2025	2024	B (W)
MERC			
Heating (941 Normal)	**892**	817	9.2 %
MGU			
Heating (772 Normal)	**817**	524	55.9 %

[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 service territories.

Gross Margin GAAP and Utility Margin Non-GAAP

The following table summarizes our other states segment gross margin (GAAP) and reconciles gross margin (GAAP) to utility margin (non-GAAP). See "Non-GAAP Financial Measures" above for additional information regarding gross margin (GAAP) and utility margin (non-GAAP).

	Three Months Ended June 30		
(in millions)	**2025**	**2024**	**B (W)**
Operating revenues	**$ 82.3**	$ 71.0	$ 11.3
Operating expenses			
Cost of natural gas sold	**(30.0)**	(23.8)	(6.2)
Other operation and maintenance [(1)]	**(15.0)**	(14.8)	(0.2)
Depreciation and amortization	**(12.3)**	(11.5)	(0.8)
Property and revenue taxes	**(6.8)**	(6.3)	(0.5)
Gross margin (GAAP)	**18.2**	14.6	3.6
Other operation and maintenance [(1)]	**15.0**	14.8	0.2
Depreciation and amortization	**12.3**	11.5	0.8
Property and revenue taxes	**6.8**	6.3	0.5
Utility margin (non-GAAP)	**$ 52.3**	$ 47.2	$ 5.1

(1) Operating and maintenance expenses deemed to be directly attributable to our revenue-producing activities include distribution and customer service expenses. These expenses are included in the above table to calculate gross margin as defined under GAAP.

Gross margin (GAAP) increased $3.6 million during the second quarter of 2025, compared with the same quarter in 2024, and utility margin (non-GAAP) increased $5.1 million during the second quarter of 2025, compared with the same quarter in 2024. Both measures were driven by:

- A $3.2 million increase related to MGU's approved rate increase that was effective January 1, 2025, and MERC's rate increase that was effective March 1, 2024.

- A $0.8 million increase related to MERC CIP revenue, which was offset in operation and maintenance expense. Rebates and programs are available to residential and commercial customers of MERC through the CIP, which is funded by rate payers using the Conservation Cost Recovery Charge and the Conservation Cost Recovery Adjustment funds that are collected on their monthly billing statements.

Additionally, the lower increase in gross margin (GAAP) as compared to the increase in utility margin (non-GAAP), was driven by a $0.8 million increase in depreciation and amortization expense that is further described in Other Operating Expenses below.

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

Other operating expenses at the other states segment increased $0.6 million during the second quarter of 2025, compared with the same quarter in 2024. The significant factors impacting the increase in operating expenses were:

- A $0.8 million increase in depreciation and amortization expense related to continued capital investment.

- A $0.8 million increase in operation and maintenance expense related to MERC's CIP program, which has an offsetting increase in margins.

These increases in other operating expenses were partially offset by a $1.4 million decrease in bad debt expense, primarily due to an increase in MGU's reserve in 2024 due to aging arrears.

Interest Expense

Interest expense at the other states segment increased $0.7 million during the second quarter of 2025, compared with the same quarter in 2024, driven by the impact of MERC issuing long-term debt in April 2025 and MGU issuing long-term debt in October 2024 and April 2025.

Income Tax Expense

Income tax expense at the other states segment increased $0.9 million during the second quarter of 2025, compared with the same quarter in 2024, driven by higher pre-tax income.

Electric Transmission Segment Contribution to Net Income Attributed to Common Shareholders

	Three Months Ended June 30		
(in millions)	**2025**	**2024**	**B (W)**
Equity in earnings of transmission affiliates	**$ 51.9**	$ 46.8	$ 5.1
Interest expense	**4.9**	4.9	—
Income before income taxes	**47.0**	41.9	5.1
Income tax expense	**11.4**	10.5	(0.9)
Net income attributed to common shareholders	**$ 35.6**	$ 31.4	$ 4.2

Equity in Earnings of Transmission Affiliates

Equity in earnings of transmission affiliates increased $5.1 million during the second quarter of 2025, compared with the same quarter in 2024. This increase was primarily due to continued capital investment by ATC.

Income Tax Expense

Income tax expense at the electric transmission segment increased $0.9 million during the second quarter of 2025, compared with the same quarter in 2024, driven by higher pre-tax income.

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

	Three Months Ended June 30		
(in millions)	**2025**	**2024**	**B (W)**
Operating income	**$ 71.5**	$ 95.4	$ (23.9)
Other income, net	**0.7**	0.2	0.5
Interest expense	**31.5**	24.1	(7.4)
Income before income taxes	**40.7**	71.5	(30.8)
Income tax benefit	**(38.9)**	(20.2)	18.7
Net loss attributed to noncontrolling interests	**2.7**	1.6	1.1
Net income attributed to common shareholders	**$ 82.3**	$ 93.3	$ (11.0)

Operating Income

Operating income at the non-utility energy infrastructure segment decreased $23.9 million during the second quarter of 2025, compared with the same quarter in 2024, driven by these items at WECI:

- A $15.2 million negative impact related to the receipt of performance payments in 2024.
- An $11.6 million impairment loss recorded at our Samson I and Delilah I solar facilities related to damage incurred associated with various storms. See Note 6, Property, Plant, and Equipment, for more information.

- A $5.2 million increase in operation and maintenance expenses due primarily to a higher number of equipment repairs at our renewable generation facilities.

These decreases in operating income were partially offset by a $9.1 million increase in operating income from new investments in several WECI renewable generation facilities made in late 2024 and early 2025.

Interest Expense

Interest expense at the non-utility energy infrastructure segment increased $7.4 million during the second quarter of 2025, compared with the same quarter in 2024, driven by the impact of WECI Energy Holding III issuing long-term debt in December 2024.

Income Tax Benefit

The income tax benefit at the non-utility energy infrastructure segment increased $18.7 million during the second quarter of 2025, compared with the same quarter in 2024, due to an increase in PTCs that was related to the acquisition of additional renewable generation facilities and an IRS approved PTC rate increase, partially offset by lower production volumes. Also contributing to the favorable income tax variance was lower pre-tax income.

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

	Three Months Ended June 30		
(in millions)	**2025**	**2024**	**B (W)**
Operating loss	**$ (2.5)**	$ (1.4)	$ (1.1)
Other income, net	**11.6**	12.5	(0.9)
Interest expense	**88.5**	76.5	(12.0)
Loss before income taxes	**(79.4)**	(65.4)	(14.0)
Income tax expense	**1.6**	6.4	4.8
Net loss attributed to common shareholders	**$ (81.0)**	$ (71.8)	$ (9.2)

Interest Expense

Interest expense at the corporate and other segment increased $12.0 million during the second quarter of 2025, compared with the same quarter in 2024, due to the impact of long-term debt issuances by WEC Energy Group in June 2024, December 2024, and June 2025. Partially offsetting this increase in interest expense was lower average short-term debt balances and lower average short-term interest rates.

Income Tax Expense

Income tax expense at the corporate and other segment decreased $4.8 million during the second quarter of 2025, compared with the same quarter in 2024. This decrease was driven by a higher pre-tax loss.

SIX MONTHS ENDED JUNE 30, 2025

Consolidated Earnings

The following table compares our consolidated results for the six months ended June 30, 2025 with the six months ended June 30, 2024, including favorable or better, "B", and unfavorable or worse, "W", variances:

	Six Months Ended June 30		
(in millions, except per share data)	**2025**	**2024**	**B (W)**
Wisconsin	**$ 542.3**	$ 398.5	$ 143.8
Illinois	**200.7**	213.2	(12.5)
Other states	**46.6**	39.2	7.4
Electric transmission	**72.5**	61.5	11.0
Non-utility energy infrastructure	**191.1**	187.6	3.5
Corporate and other	**(83.6)**	(66.4)	(17.2)
Net income attributed to common shareholders	**$ 969.6**	$ 833.6	$ 136.0
Diluted EPS	**$ 3.02**	$ 2.64	$ 0.38

Earnings increased $136.0 million during the six months ended June 30, 2025, compared with the same period in 2024. The significant factors impacting the $136.0 million increase in earnings were:

- A $143.8 million increase in net income attributed to common shareholders at the Wisconsin segment, driven by higher margins from the impact of the Wisconsin rate orders approved by the PSCW, effective January 1, 2025, and higher retail sales volumes. These positive impacts were partially offset by higher operating expenses, primarily due to increases in depreciation and amortization expense and transmission expense.

- An $11.0 million increase in net income attributed to common shareholders at the electric transmission segment, driven by continued capital investment by ATC and a gain related to the sale of an investment at ATC Holdco in March 2025.

These increases in earnings were partially offset by:

- A $17.2 million increase in the net loss attributed to common shareholders at the corporate and other segment, driven by higher interest expense and a decrease in earnings from our equity method investments in technology and energy-focused investment funds. These decreases in earnings were partially offset by a positive impact from an increase in an interim income tax benefit recorded to adjust consolidated income tax expense to the projected, annualized consolidated effective income tax rate.

- A $12.5 million decrease in net income attributed to common shareholders at the Illinois segment, driven by higher operating expenses. The period-over-period impact from a favorable settlement of a legal claim during 2024 and an increase in costs associated with maintenance at the Manlove Gas Storage Field drove the higher operating expenses.

Expected 2025 Annual Effective Tax Rate

We expect our 2025 annual effective tax rate to be between 7.5% and 8.5%. 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.

Non-GAAP Financial Measures

The discussions below address the contribution of each of our utility segments to net income attributed to common shareholders. The discussions include financial information prepared in accordance with GAAP, as well as utility margin, which is not a measure of financial performance under GAAP. Utility margin (operating revenues less fuel and purchased power costs and cost of natural gas sold) is a non-GAAP financial measure because it excludes certain operation and maintenance expenses applicable to revenues, as well as depreciation and amortization and property and revenue taxes.

We believe that utility margin provides 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 utility margin internally when assessing the operating performance of our utility segments as these measures exclude the majority of revenue fluctuations caused by changes in these expenses. Similarly, the presentation of utility margin herein is intended to provide supplemental information for investors regarding our operating performance.

Our utility margin may not be comparable to similar measures presented by other companies. Furthermore, this measure is not intended to replace gross margin as determined in accordance with GAAP as an indicator of operating performance. Each of our three utility segment discussions below include a table that provides the calculation of both gross margin as determined in accordance with GAAP and utility margin, as well as a reconciliation between the two measures.

Wisconsin Segment Contribution to Net Income Attributed to Common Shareholders

The Wisconsin segment's contribution to net income attributed to common shareholders was $542.3 million during the six months ended June 30, 2025, representing a $143.8 million, or 36.1%, increase over the same period in 2024. The increase in earnings was driven by higher margins from the impact of the Wisconsin rate orders approved by the PSCW, effective January 1, 2025, and higher retail sales volumes. These positive impacts were partially offset by higher operating expenses, primarily due to increases in depreciation and amortization expense and transmission expense.

	Six Months Ended June 30		
(in millions)	2025	2024	B (W)
Operating revenues	**$ 3,647.1**	$ 3,147.0	$ 500.1
Operating expenses			
Cost of sales [1]	**1,289.0**	1,065.0	(224.0)
Other operation and maintenance	**831.1**	779.1	(52.0)
Depreciation and amortization	**493.8**	452.9	(40.9)
Property and revenue taxes	**90.5**	92.2	1.7
Operating income	**942.7**	757.8	184.9
Other income, net	**37.4**	65.7	(28.3)
Interest expense	**319.7**	315.1	(4.6)
Income before income taxes	**660.4**	508.4	152.0
Income tax expense	**117.5**	109.3	(8.2)
Preferred stock dividends of subsidiary	**0.6**	0.6	—
Net income attributed to common shareholders	**$ 542.3**	$ 398.5	$ 143.8

[1] Cost of sales includes fuel and purchased power and cost of natural gas sold.

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

	Six Months Ended June 30		
(in millions)	2025	2024	B (W)
Operation and maintenance not included in line items below	**$ 357.0**	$ 334.9	$ (22.1)
Transmission [1]	**292.9**	271.5	(21.4)
Regulatory amortizations and other pass through expenses [2]	**118.8**	107.7	(11.1)
We Power [3]	**65.1**	66.7	1.6
Earnings sharing mechanisms	**(2.7)**	(1.7)	1.0
Total other operation and maintenance	**$ 831.1**	$ 779.1	$ (52.0)

[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 the six months ended June 30, 2025 and 2024, $308.8 million and $277.8 million, respectively, of costs were billed to our electric utilities by transmission providers.

Table of Contents

(2) Regulatory amortizations and other pass through expenses are substantially offset in margins and therefore do not have a significant impact on net income.

(3) Represents costs associated with the We Power generation units, including operating and maintenance costs recognized by WE. During the six months ended June 30, 2025 and 2024, $60.0 million and $58.8 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.

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

	Six Months Ended June 30		
	MWh *(in thousands)*		
Electric Sales Volumes	**2025**	**2024**	**B (W)**
Customer Class			
Residential	**5,361.1**	5,172.8	188.3
Small commercial and industrial [1]	**6,323.3**	6,236.9	86.4
Large commercial and industrial [1]	**5,856.6**	5,866.1	(9.5)
Other	**58.7**	62.7	(4.0)
Total retail [1]	**17,599.7**	17,338.5	261.2
Wholesale	**866.5**	835.1	31.4
Resale	**2,818.6**	2,718.5	100.1
Total sales in MWh [1]	**21,284.8**	20,892.1	392.7

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

	Six Months Ended June 30		
	Therms *(in millions)*		
Natural Gas Sales Volumes	**2025**	**2024**	**B (W)**
Customer Class			
Residential	**703.1**	590.6	112.5
Commercial and industrial	**442.2**	368.6	73.6
Total retail	**1,145.3**	959.2	186.1
Transportation	**731.2**	689.8	41.4
Total sales in therms	**1,876.5**	1,649.0	227.5

	Six Months Ended June 30		
	Degree Days		
Weather	**2025**	**2024**	**B (W)**
WE and WG [1]			
Heating (4,088 Normal)	**4,296**	3,332	28.9 %
Cooling (182 Normal)	**176**	202	(12.9)%
WPS [2]			
Heating (4,518 Normal)	**4,414**	3,798	16.2 %
Cooling (157 Normal)	**160**	142	12.7 %
UMERC [3]			
Heating (5,081 Normal)	**5,080**	4,491	13.1 %
Cooling (88 Normal)	**102**	57	78.9 %

(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.

Gross Margin GAAP and Utility Margin Non-GAAP

The following table summarizes our Wisconsin segment gross margin (GAAP) and reconciles gross margin (GAAP) to utility margin (non-GAAP). See Non-GAAP Financial Measures above for additional information regarding gross margin (GAAP) and utility margin (non-GAAP).

	Six Months Ended June 30		
(in millions)	**2025**	**2024**	**B (W)**
Electric revenues	**$ 2,631.6**	$ 2,341.6	$ 290.0
Natural gas revenues	**1,015.5**	805.4	210.1
Operating revenues	**3,647.1**	3,147.0	500.1
Operating expenses			
Fuel and purchased power	**(782.1)**	(681.5)	(100.6)
Cost of natural gas sold	**(506.9)**	(383.5)	(123.4)
Other operation and maintenance [(1)]	**(604.7)**	(567.8)	(36.9)
Depreciation and amortization	**(493.8)**	(452.9)	(40.9)
Property and revenue taxes	**(90.5)**	(92.2)	1.7
Gross margin (GAAP)	**1,169.1**	969.1	200.0
Other operation and maintenance [(1)]	**604.7**	567.8	36.9
Depreciation and amortization	**493.8**	452.9	40.9
Property and revenue taxes	**90.5**	92.2	(1.7)
Utility margin (non-GAAP)	**$ 2,358.1**	$ 2,082.0	$ 276.1

(1) Operating and maintenance expenses deemed to be directly attributable to our revenue-producing activities include plant operating and maintenance expenses related to our generating units; costs associated with the We Power generating units; and transmission, distribution and customer service expenses. These expenses are included in the above table to calculate gross margin as defined under GAAP.

Gross margin (GAAP) at the Wisconsin segment increased $200.0 million during the six months ended June 30, 2025, compared with the same period in 2024, and utility margin (non-GAAP) increased $276.1 million during the six months ended June 30, 2025, compared with the same period in 2024. Both measures were driven by:

- A $198.8 million increase in margins driven by the impact of the Wisconsin rate orders approved by the PSCW, effective January 1, 2025.

- An $84.1 million increase in margins related to higher retail sales volumes, driven by the impact of colder weather during the six months ended June 30, 2025, compared with the same period in 2024. As measured by heating degree days, the six months ended June 30, 2025 were 28.9% and 16.2% colder than the same period in 2024 in the Milwaukee area and Green Bay area, respectively.

These increases in margins were partially offset by a $5.6 million period-over-period negative 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 above or below the 2% is generally deferred for either future recovery from or refund to customers.

Additionally, the smaller increase in gross margin (GAAP) as compared with the increase in utility margin (non-GAAP), was driven by the following items that are further described in Other Operating Expenses below:

- A $40.9 million increase in depreciation and amortization expense;

- A $21.4 million increase in transmission expense;

- A $13.0 million increase in electric and natural gas distribution expenses; and

- A $5.4 million increase in other operating and maintenance related to our power plants.

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

Other operating expenses at the Wisconsin segment increased $91.2 million during the six months ended June 30, 2025, compared with the same period in 2024. The significant factors impacting the increase in other operating expenses were:

- A $40.9 million increase in depreciation and amortization expense, driven by assets being placed into service as we continue to execute on our capital plan.

- A $21.4 million increase in transmission expense as approved by the PSCW in our Wisconsin rate orders, effective January 1, 2025. See the notes under the other operation and maintenance table above for more information.

- A $13.0 million increase in electric and natural gas distribution expenses, driven by higher costs to maintain the distribution systems during the six months ended June 30, 2025, compared with the same period in 2024.

- An $11.1 million increase in regulatory amortizations and other pass through expenses, as discussed in the notes under the other operation and maintenance table above.

- A $5.4 million increase in other operating and maintenance related to our power plants, driven by outages at the Weston coal-fired generation facility and inspections at the Fox Energy Center natural gas-fired generation facility.

Other Income, Net

Other income, net at the Wisconsin segment decreased $28.3 million during the six months ended June 30, 2025, compared with the same period in 2024, driven by a $44.0 million negative impact from the non-service components of our net periodic pension and OPEB costs. This decrease was partially offset by a $13.3 million positive impact from higher AFUDC-Equity due to continued capital investment.

Interest Expense

Interest expense at the Wisconsin segment increased $4.6 million during the six months ended June 30, 2025, compared with the same period in 2024. The increase was primarily driven by the impact of WE, WPS, and WG issuing long-term debt in 2024. Partially offsetting the increase was lower average short-term debt balances, lower short-term debt interest rates, and higher AFUDC-Debt due to continued capital investment.

Income Tax Expense

Income tax expense at the Wisconsin segment increased $8.2 million during the six months ended June 30, 2025, compared with the same period in 2024, driven by higher pre-tax income. Partially offsetting this increase in income tax expense were higher PTCs and the increased benefit from the flow through of tax repairs in connection with the Wisconsin rate orders approved by the PSCW, effective January 1, 2025. Also reducing income tax expense were increases in the protected deferred tax benefits associated with the Tax Legislation and increases in income tax benefits associated with AFUDC-Equity, driven by continued capital investment.

Illinois Segment Contribution to Net Income Attributed to Common Shareholders

The Illinois segment's contribution to net income attributed to common shareholders was $200.7 million during the six months ended June 30, 2025, representing a $12.5 million, or 5.9%, decrease over the same period in 2024. The decrease was driven by higher operating expenses, primarily due to the period-over-period impact from a favorable settlement of a legal claim during 2024 and an increase in costs associated with maintenance at the Manlove Gas Storage Field.

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.

	Six Months Ended June 30		
(in millions)	**2025**	**2024**	**B (W)**
Operating revenues	**$ 1,058.9**	$ 942.8	$ 116.1
Operating expenses			
Cost of natural gas sold	**317.7**	236.5	(81.2)
Other operation and maintenance	**259.3**	209.6	(49.7)
Depreciation and amortization	**129.2**	127.2	(2.0)
Property and revenue taxes	**33.2**	29.7	(3.5)
Operating income	**319.5**	339.8	(20.3)
Other income, net	**4.4**	4.2	0.2
Interest expense	**45.3**	48.5	3.2
Income before income taxes	**278.6**	295.5	(16.9)
Income tax expense	**77.9**	82.3	4.4
Net income attributed to common shareholders	**$ 200.7**	$ 213.2	$ (12.5)

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

	Six Months Ended June 30		
(in millions)	**2025**	**2024**	**B (W)**
Operation and maintenance not included in the line items below	**$ 161.8**	$ 143.4	$ (18.4)
Riders [(1)]	**96.2**	64.7	(31.5)
Regulatory amortizations [(1)]	**1.3**	1.5	0.2
Total other operation and maintenance	**$ 259.3**	$ 209.6	$ (49.7)

[(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:

	Six Months Ended June 30		
	Therms *(in millions)*		
Natural Gas Sales Volumes	**2025**	**2024**	**B (W)**
Customer Class			
Residential	**534.2**	457.8	76.4
Commercial and industrial	**194.6**	174.3	20.3
Total retail	**728.8**	632.1	96.7
Transportation	**457.4**	410.3	47.1
Total sales in therms	**1,186.2**	1,042.4	143.8

	Six Months Ended June 30		
	Degree Days		
Weather [(1)]	**2025**	**2024**	**B (W)**
Heating (3,781 Normal)	**3,740**	3,064	22.1 %

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

Gross Margin GAAP and Utility Margin Non-GAAP

The following table summarizes our Illinois segment gross margin (GAAP) and reconciles gross margin (GAAP) to utility margin (non-GAAP). See Non-GAAP Financial Measures above for additional information regarding gross margin (GAAP) and utility margin (non-GAAP).

	Six Months Ended June 30		
(in millions)	**2025**	**2024**	**B (W)**
Operating revenues	**$ 1,058.9**	$ 942.8	$ 116.1
Operating expenses			
Cost of natural gas sold	**(317.7)**	(236.5)	(81.2)
Other operation and maintenance [1]	**(121.0)**	(110.1)	(10.9)
Depreciation and amortization	**(129.2)**	(127.2)	(2.0)
Property and revenue taxes	**(33.2)**	(29.7)	(3.5)
Gross margin (GAAP)	**457.8**	439.3	18.5
Other operation and maintenance [1]	**121.0**	110.1	10.9
Depreciation and amortization	**129.2**	127.2	2.0
Property and revenue taxes	**33.2**	29.7	3.5
Utility margin (non-GAAP)	**$ 741.2**	$ 706.3	$ 34.9

[1] Operating and maintenance expenses deemed to be directly attributable to our revenue-producing activities include distribution and customer service expenses. These expenses are included in the above table to calculate gross margin as defined under GAAP.

Gross margin (GAAP) at the Illinois segment increased $18.5 million during the six months ended June 30, 2025, compared with the same period in 2024, and utility margin (non-GAAP) increased $34.9 million during the six months ended June 30, 2025, compared with the same period in 2024. Both measures were driven by:

- A $31.5 million increase in revenues associated with certain riders that are offset in other operation and maintenance and therefore do not have a significant impact on net income.

- A $2.2 million increase in revenues related to the impact of the NSG rate order issued by the ICC, effective February 1, 2024.

Additionally, the smaller increase in gross margin (GAAP) as compared with the increase in utility margin (non-GAAP), was driven by the following items that are further described in Other Operating Expenses below:

- A $6.0 million increase in costs associated with maintenance at the Manlove Gas Storage Field;

- A $3.7 million increase in natural gas distribution and maintenance costs;

- A $3.5 million increase in property and revenue taxes; and

- A $2.0 million increase in depreciation and amortization.

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

Other operating expenses at the Illinois segment increased $23.7 million, net of the $31.5 million impact of the riders referenced in the table above, during the six months ended June 30, 2025, compared with the same period in 2024. The significant factors impacting the increase in other operating expenses were:

- An $11.6 million increase in expense primarily associated with the favorable settlement of a legal claim during the six months ended June 30, 2024.

- A $6.0 million increase in costs associated with maintenance at the Manlove Gas Storage Field.

- A $3.7 million increase in natural gas distribution and maintenance costs, primarily related to maintaining the natural gas infrastructure.
- A $3.5 million increase in property and revenue taxes, driven by an increase in property taxes and use taxes.
- A $2.0 million increase in benefit costs, driven by higher stock-based compensation and deferred compensation expense.
- A $2.0 million increase in depreciation and amortization expense, driven by assets being placed into service as we continue to execute on our capital plan.

These increases in operating expenses were partially offset by a $2.2 million pre-tax gain on the renegotiation of a lease contract during the six months ended June 30, 2025.

Interest Expense

Interest expense at the Illinois segment decreased $3.2 million during the six months ended June 30, 2025, compared with the same period in 2024, due to lower average short-term debt balances, lower short-term debt interest rates, and the impact of a series of PGL's first mortgage bonds maturing in November 2024.

Income Tax Expense

Income tax expense at the Illinois segment decreased $4.4 million during the six months ended June 30, 2025, compared with the same period in 2024, 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 was $46.6 million during the six months ended June 30, 2025, representing a $7.4 million, or 18.9%, increase over the same period in 2024. The increase was driven by higher margins related to positive impacts from MGU's rate increase that was effective January 1, 2025, MERC's rate increase that was effective March 1, 2024, and an increase in retail sales volumes. These increases in earnings were partially offset by higher operating expenses.

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

	Six Months Ended June 30		
(in millions)	**2025**	**2024**	**B (W)**
Operating revenues	**$ 309.4**	$ 255.6	$ 53.8
Operating expenses			
Cost of natural gas sold	**147.6**	114.6	(33.0)
Other operation and maintenance	**52.6**	45.2	(7.4)
Depreciation and amortization	**24.5**	22.9	(1.6)
Property and revenue taxes	**13.3**	12.5	(0.8)
Operating income	**71.4**	60.4	11.0
Other income, net	**0.2**	0.1	0.1
Interest expense	**9.0**	8.0	(1.0)
Income before income taxes	**62.6**	52.5	10.1
Income tax expense	**16.0**	13.3	(2.7)
Net income attributed to common shareholders	**$ 46.6**	$ 39.2	$ 7.4

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

	Six Months Ended June 30		
(in millions)	**2025**	**2024**	**B (W)**
Operation and maintenance not included in line item below	**$ 39.3**	$ 36.4	$ (2.9)
Regulatory amortizations and other pass through expenses [1]	**13.3**	8.8	(4.5)
Total other operation and maintenance	**$ 52.6**	$ 45.2	$ (7.4)

[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:

	Six Months Ended June 30		
	Therms *(in millions)*		
Natural Gas Sales Volumes	**2025**	**2024**	**B (W)**
Customer Class			
Residential	**201.2**	173.2	28.0
Commercial and industrial	**123.2**	106.7	16.5
Total retail	**324.4**	279.9	44.5
Transportation	**390.9**	424.6	(33.7)
Total sales in therms	**715.3**	704.5	10.8

	Six Months Ended June 30		
	Degree Days		
Weather [1]	**2025**	**2024**	**B (W)**
MERC			
Heating (4,854 Normal)	**4,790**	4,179	14.6 %
MGU			
Heating (3,882 Normal)	**3,823**	3,211	19.1 %

[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 service territories.

Gross Margin GAAP and Utility Margin Non-GAAP

The following table summarizes our other states segment gross margin (GAAP) and reconciles gross margin (GAAP) to utility margin (non-GAAP). See Non-GAAP Financial Measures above for additional information regarding gross margin (GAAP) and utility margin (non-GAAP).

	Six Months Ended June 30		
(in millions)	**2025**	**2024**	**B (W)**
Operating revenues	**$ 309.4**	$ 255.6	$ 53.8
Operating expenses			
Cost of natural gas sold	**(147.6)**	(114.6)	(33.0)
Other operation and maintenance [1]	**(29.5)**	(27.0)	(2.5)
Depreciation and amortization	**(24.5)**	(22.9)	(1.6)
Property and revenue taxes	**(13.3)**	(12.5)	(0.8)
Gross margin (GAAP)	**94.5**	78.6	15.9
Other operation and maintenance [1]	**29.5**	27.0	2.5
Depreciation and amortization	**24.5**	22.9	1.6
Property and revenue taxes	**13.3**	12.5	0.8
Utility margin (non-GAAP)	**$ 161.8**	$ 141.0	$ 20.8

[1] Operating and maintenance expenses deemed to be directly attributable to our revenue-producing activities include distribution and customer service expenses. These expenses are included in the above table to calculate gross margin as defined under GAAP.

Gross margin (GAAP) increased $15.9 million during the six months ended June 30, 2025, compared with the same period in 2024, and utility margin (non-GAAP) increased $20.8 million during the six months ended June 30, 2025, compared with the same period in 2024. Both measures were driven by:

- A $7.6 million increase related to MGU's rate increase that was effective January 1, 2025, and MERC's rate increase that was effective March 1, 2024.

- A $7.4 million increase related to higher sales volumes, driven by colder weather during the six months ended June 30, 2025, as compared to the same period in 2024. As measured by heating degree days, the six months ended June 30, 2025 was 14.6% and 19.1% colder than the same period in 2024 at MERC and MGU, respectively.

- A $3.4 million increase related to MERC CIP revenue, which was offset in operation and maintenance expense.

Additionally, the lower increase in gross margin (GAAP) as compared to the increase in utility margin (non-GAAP), was driven by the following items that are further described in Other Operating Expenses below:

- A $2.5 million increase in natural gas operations and customer service expense; and

- A $1.6 million increase in depreciation and amortization expense.

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

Other operating expenses at the other states segment increased $9.8 million during the six months ended June 30, 2025, compared with the same period in 2024. The significant factors impacting the increase in operating expenses were:

- A $3.4 million increase in operation and maintenance expense related to MERC's CIP program, which has an offsetting increase in margins.

- A $2.5 million increase in natural gas operations and customer service expense, driven by higher metering costs at MERC and MGU.

- A $1.9 million increase in bad debt expense, primarily at MERC. MERC's bad debt expense was lower in 2024 due to reserve adjustments related to improved loss rates.

- A $1.6 million increase in depreciation and amortization expense related to continued capital investment.

Interest Expense

Interest expense at the other states segment increased $1.0 million during the six months ended June 30, 2025, compared with the same period in 2024, driven by the impact of MERC issuing long-term debt in April 2025 and MGU issuing long-term debt in October 2024 and April 2025.

Income Tax Expense

Income tax expense at the other states segment increased $2.7 million during the six months ended June 30, 2025, compared with the same period in 2024, driven by higher pre-tax income.

Electric Transmission Segment Contribution to Net Income Attributed to Common Shareholders

	Six Months Ended June 30		
(in millions)	2025	2024	B (W)
Equity in earnings of transmission affiliates	**$ 105.5**	$ 91.6	$ 13.9
Interest expense	**9.7**	9.7	—
Income before income taxes	**95.8**	81.9	13.9
Income tax expense	**23.3**	20.4	(2.9)
Net income attributed to common shareholders	**$ 72.5**	$ 61.5	$ 11.0

Equity in Earnings of Transmission Affiliates

Equity in earnings of transmission affiliates increased $13.9 million during the six months ended June 30, 2025, compared with the same period in 2024. This increase was primarily due to continued capital investment by ATC. A $3.6 million gain related to the sale of an investment at ATC Holdco in March 2025 also contributed to the increase.

Income Tax Expense

Income tax expense at the electric transmission segment increased $2.9 million during the six months ended June 30, 2025, compared with the same period in 2024, primarily due to an increase in pre-tax income.

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

	Six Months Ended June 30		
(in millions)	2025	2024	B (W)
Operating income	**$ 175.6**	$ 190.4	$ (14.8)
Other income, net	**1.4**	0.2	1.2
Interest expense	**62.1**	48.2	(13.9)
Income before income taxes	**114.9**	142.4	(27.5)
Income tax benefit	**(74.5)**	(43.6)	30.9
Net loss attributed to noncontrolling interests	**1.7**	1.6	0.1
Net income attributed to common shareholders	**$ 191.1**	$ 187.6	$ 3.5

Operating Income

Operating income at the non-utility energy infrastructure segment decreased $14.8 million during the six months ended June 30, 2025, compared with the same period in 2024, driven by these items at WECI:

- A $15.2 million negative impact related to the receipt of performance payments in 2024.
- An $11.6 million impairment loss recorded at our Samson I and Delilah I solar facilities related to damage incurred associated with various storms.
- A $6.0 million increase in operation and maintenance expenses due primarily to a higher number of equipment repairs at our renewable generation facilities.

These decreases in operating income were partially offset by:

- A $9.7 million increase in operating income from new investments in several WECI renewable generation facilities made in late 2024 and early 2025.
- A $3.5 million increase due to higher amounts recognized for REC sales in 2025 at Blooming Grove driven by higher contracted REC prices overall, as well as timing of REC contract execution.
- Recognition of $2.5 million of business interruption insurance proceeds related to storms at our Samson I solar facility.

In addition to the above items at WECI, there was a $1.6 million positive impact from We Power due to continued capital investment.

Interest Expense

Interest expense at the non-utility energy infrastructure segment increased $13.9 million during the six months ended June 30, 2025, compared with the same period in 2024, driven by the impact of WECI Energy Holding III issuing long-term debt in December 2024.

Income Tax Benefit

The income tax benefit at the non-utility energy infrastructure segment increased $30.9 million during the six months ended June 30, 2025, compared with the same period in 2024. The increase was primarily due to an increase in PTCs that was related to the acquisition of additional renewable generation facilities and an IRS approved PTC rate increase, partially offset by lower production volumes. Also contributing to the favorable income tax variance was lower pre-tax income.

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

	Six Months Ended June 30		
(in millions)	**2025**	**2024**	**B (W)**
Operating loss	**$ (4.8)**	$ (3.7)	$ (1.1)
Other income, net	**16.6**	28.0	(11.4)
Interest expense	**175.4**	143.1	(32.3)
Loss before income taxes	**(163.6)**	(118.8)	(44.8)
Income tax benefit	**(80.0)**	(52.4)	27.6
Net loss attributed to common shareholders	**$ (83.6)**	$ (66.4)	$ (17.2)

Other Income, Net

Other income, net at the corporate and other segment decreased $11.4 million during the six months ended June 30, 2025, compared with the same period in 2024. The significant factors impacting the decrease in other income, net were:

- A $7.4 million decrease due to net losses of $4.1 million from our equity method investments in technology and energy-focused investment funds during the six months ended June 30, 2025, compared with net earnings of $3.3 million during the same period in 2024.

- A $3.6 million decrease due to lower net gains from the investments held in the Integrys rabbi trust during the six months ended June 30, 2025, compared with the same period in 2024. The gains from the investments held in the rabbi trust partially offset increases in benefit costs related to certain deferred compensation, which are primarily included in other operation and maintenance expense in our utility segments.

Interest Expense

Interest expense at the corporate and other segment increased $32.3 million during the six months ended June 30, 2025, compared with the same period in 2024, primarily due to the impact of long-term debt issuances by WEC Energy Group in June 2024, December 2024, and June 2025. Partially offsetting these increases in interest expense were lower average short-term debt balances and lower average short-term interest rates.

Income Tax Benefit

The Income tax benefit at the corporate and other segment increased $27.6 million during the six months ended June 30, 2025, compared with the same period in 2024. This increase was driven by a $13.6 million increase in the interim tax benefit recorded to adjust consolidated income tax expense to the projected, annualized consolidated effective income tax rate, as well as a higher pre-tax loss.

LIQUIDITY AND CAPITAL RESOURCES

Overview

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

Cash Flows

The following table summarizes our cash flows during the six months ended June 30:

(in millions)	2025	2024	Change in 2025 Over 2024
Cash provided by (used in):			
Operating activities	**$ 2,015.9**	$ 1,901.0	$ 114.9
Investing activities	**(1,972.8)**	(1,250.8)	(722.0)
Financing activities	**(16.1)**	(512.5)	496.4

Operating Activities

Net cash provided by operating activities increased $114.9 million during the six months ended June 30, 2025, compared with the same period in 2024, driven by:

- A $254.6 million increase in cash from higher overall collections from customers during the six months ended June 30, 2025, compared with the same period in 2024. This increase was driven by the impact of the Wisconsin rate orders approved by the PSCW, effective January 1, 2025, a higher per-unit cost of natural gas, and higher sales volumes from colder weather during the six months ended June 30, 2025, compared with the same period in 2024.

- A $49.8 million increase in cash from lower payments for environmental remediation related to work completed on former manufactured gas plant sites during the six months ended June 30, 2025, compared with the same period in 2024.

- A $34.3 million increase in cash driven by collateral received from counterparties during the six months ended June 30, 2025, compared with collateral paid to counterparties during the same period in 2024, as well as realized gains on derivative instruments recognized during the six months ended June 30, 2025, compared with realized losses on derivative instruments recognized during the same period in 2024.

- A $30.1 million increase in cash from higher distributions from ATC during the six months ended June 30, 2025, compared with the same period in 2024.

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

- A $164.9 million decrease in cash from higher payments for operating and maintenance expenses. During the six months ended June 30, 2025, our payments were higher due to higher transmission and electric and natural gas distribution costs, as well as the timing of payments for accounts payable.

- A $51.5 million decrease in cash from higher payments for interest driven by issuances of long-term debt in 2024, partially offset by lower payments for interest due to lower average short-term debt balances and lower short-term interest rates during the six months ended June 30, 2025, compared with the same period in 2024.

- A $39.6 million decrease in cash received for income taxes driven by the timing of proceeds received from the sale of PTCs to third parties during the six months ended June 30, 2025, compared with the same period in 2024. See Note 12, Income Taxes, and Note 22, Supplemental Cash Flow Information, for more information.

Investing Activities

Net cash used in investing activities increased $722.0 million during the six months ended June 30, 2025, compared with the same period in 2024, driven by:

- The acquisition of a 90% ownership interest in Hardin III in February 2025 for $406.1 million, net of cash acquired of $0.2 million. See Note 2, Acquisitions, for more information.

- A $392.1 million increase in cash paid for capital expenditures during the six months ended June 30, 2025, which is discussed in more detail below.

- A $57.5 million increase in capital contributions paid to transmission affiliates during the six months ended June 30, 2025, compared with the same period in 2024. See Note 18, Investment in Transmission Affiliates, for more information.

These increases in net cash used in investing activities were partially offset by:

- The acquisition of an additional 13.7% ownership interest in West Riverside in May 2024 for $98.2 million. See Note 2, Acquisitions, for more information.

- A $33.5 million increase in cash received from ATC during the six months ended June 30, 2025, compared with the same period in 2024, for the reimbursement of transmission infrastructure upgrades. See Note 18, Investment in Transmission Affiliates, for more information.

Capital Expenditures

Capital expenditures by segment for the six months ended June 30 were as follows:

Reportable Segment *(in millions)*	2025	2024	Change in 2025 Over 2024
Wisconsin	**$ 1,316.4**	$ 886.8	$ 429.6
Illinois	**125.4**	169.6	(44.2)
Other states	**55.0**	49.6	5.4
Non-utility energy infrastructure	**26.0**	24.7	1.3
Corporate and other	**7.7**	7.7	—
Total capital expenditures	**$ 1,530.5**	$ 1,138.4	$ 392.1

The increase in cash paid for capital expenditures at the Wisconsin segment during the six months ended June 30, 2025, compared with the same period in 2024, was driven by an increase in capital expenditures for the following: renewable energy projects at WE, WPS, and UMERC; combustion turbines at OCPP; WE's natural gas and electric distribution systems; software to enhance productivity, collaboration, and overall efficiency across the company; and a project to consolidate our electric utility operations technology. These increases in capital expenditures were partially offset by decreased payments for construction of WG's LNG facility which was completed in February 2024.

The decrease in cash paid for capital expenditures at the Illinois segment during the six months ended June 30, 2025, compared with the same period in 2024, was driven by lower payments related to PGL's upgrade of its natural gas delivery system. For more information on the factors contributing to this decrease, see Factors Affecting Results, Liquidity, and Capital Resources – Regulatory, Legislative, and Legal Matters – Illinois Proceedings.

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

Financing Activities

Net cash used in financing activities decreased $496.4 million during the six months ended June 30, 2025, compared with the same period in 2024, driven by:

- A $952.4 million increase in cash due to lower net repayments of commercial paper during the six months ended June 30, 2025, compared with the same period in 2024.
- A $360.6 million increase in cash due to higher issuances of common stock during the six months ended June 30, 2025, compared with the same period in 2024. See Note 7, Common Equity, for more information.
- A $217.8 million increase in cash due to lower retirements of long-term debt during the six months ended June 30, 2025, compared with the same period in 2024.
- The purchase of an additional 10% ownership interest in Samson I in January 2024 for $28.1 million.
- A $20.0 million increase in cash related to a higher number of stock options exercised during the six months ended June 30, 2025, compared with the same period in 2024.

These decreases in cash used in financing were partially offset by:

- A $1,049.2 million decrease in cash due to lower issuance of long-term debt during the six months ended June 30, 2025, compared with the same period in 2024.
- A $41.5 million decrease in cash due to higher dividends paid on our common stock during the six months ended June 30, 2025, compared with the same period in 2024. In January 2025, our Board of Directors increased our quarterly dividend by $0.0575 per share (6.9%) effective with the March 2025 dividend payment.

Other Significant Financing Activities

For more information on our other significant financing activities, see Note 7, Common Equity, Note 8, Short-Term Debt and Lines of Credit, and Note 9, 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. See the discussion below and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Cash Requirements in our 2024 Annual Report on Form 10-K for additional information regarding our significant cash requirements.

Significant Capital Projects

We have several capital projects and acquisitions 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 21, Commitments and Contingencies.

(in millions)	**2025 [1]**	**2026**	**2027**
Wisconsin	**$ 4,202.4**	$ 4,410.7	$ 4,873.2
Illinois	**373.7**	404.8	369.7
Other states	**106.5**	121.4	123.4
Non-utility energy infrastructure	**437.6**	23.1	33.8
Corporate and other	**17.9**	10.2	2.4
Total	**$ 5,138.1**	$ 4,970.2	$ 5,402.5

(1) This includes actual capital expenditures incurred through June 30, 2025, as well as estimated capital expenditures for the remainder of the year.

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 natural gas-fired generation. Below are examples of projects that are proposed, currently underway, or recently completed.

- 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 located in Kenosha County, Wisconsin. In December 2024, the construction of the solar portion of Paris was completed, with WE and WPS collectively owning 180 MWs of solar generation. In June 2025, the construction of the battery portion of Paris was completed, with WE and WPS collectively owning 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.

- WE and WPS, along with an unaffiliated utility, received PSCW approval to acquire and construct Darien, a utility-scale solar-powered electric generating facility with a battery energy storage system located in Rock and Walworth counties, Wisconsin. In March 2025, the construction of the solar portion of Darien was completed, with WE and WPS collectively owning 225 MWs of solar generation. WE and WPS will collectively own 68 MWs of battery storage of this project, with construction expected to be completed in 2026. WE's and WPS's combined share of the cost of this project is estimated to be approximately $567 million.

- WE and WPS, along with an unaffiliated utility, received PSCW approval to acquire Koshkonong Solar Park, a utility-scale solar-powered electric generating facility with a battery energy storage system. The project will be located in Dane County, Wisconsin and once fully constructed, WE and WPS will collectively own 270 MWs of solar generation and 149 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 $930 million, with construction of the solar portion and battery storage expected to be completed in 2026 and 2027, respectively.

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

- WE and WPS, along with an unaffiliated utility, received PSCW approval to acquire and construct High Noon, a utility-scale solar-powered electric generating facility with a battery energy storage system. The project will be located in Columbia County, Wisconsin and once fully constructed, WE and WPS will collectively own 270 MWs of solar generation and 149 MWs of battery storage of this project. WE and WPS's combined share of the cost of this project is estimated to be approximately $883 million, with construction expected to be completed in 2027.

- UMERC received MPSC approval to acquire and construct Renegade, a utility-scale solar-powered electric generating facility. The project will be located in Delta and Marquette counties, 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 in 2026.

- WE received PSCW approval to build five natural gas-fired combustion turbines capable of producing approximately 1,100 MWs, which would be located at the existing OCPP site. The cost of this project is estimated to be approximately $1.2 billion, with construction expected to be completed in 2027-2028.

- WE received PSCW approval to add seven natural gas-fired RICE units near the Paris Generating Station. The new RICE units would be fueled with natural gas and capable of producing approximately 128 MWs. The cost of this project is estimated to be approximately $300 million, with construction expected to be completed in 2027.

- In April 2024, WE filed a request with the PSCW to construct the Rochester Lateral, which would supply additional natural gas service to the OCPP site. The natural gas lateral would be built in Kenosha, Racine, and Milwaukee counties. If approved, the cost of this project is estimated to be approximately $200 million.

- WE received PSCW approval to construct an LNG facility with storage capacity of two Bcf on the OCPP site. The cost of this project is estimated to be approximately $456 million, with construction expected to be completed in 2027.

- In September 2024, WE and WPS, along with an unaffiliated utility, filed a request with the PSCW to acquire Dawn Harvest Solar Energy Center, a utility-scale solar-powered electric generating facility with a battery energy storage system. If approved, the project will be located in Rock County, Wisconsin and once fully constructed, WE and WPS will collectively own 135 MWs of solar generation and WE will own 50 MWs of battery storage of this project. If approved, WE and WPS's combined share of the cost of this project is estimated to be approximately $409 million, with construction expected to be completed in 2028.

- In September 2024, WE and WPS, along with an unaffiliated utility, filed a request with the PSCW to acquire Saratoga, a utility-scale solar-powered electric generating facility with a battery energy storage system and Ursa, a utility-scale solar-powered electric generating facility. If approved, Saratoga will be located in Wood County, Wisconsin and Ursa will be located in Columbia County, Wisconsin. Once fully constructed, WE and WPS will collectively own 135 MWs of solar generation and 45 MWs of battery storage of Saratoga and 180 MWs of solar generation of Ursa. If approved, WE and WPS's combined share of the cost of Ursa is estimated to be approximately $406 million, with construction expected to be completed in 2027. If approved, WE and WPS's combined share of the cost of Saratoga is estimated to be approximately $406 million, with construction expected to be completed in 2028.

- In September 2024, WE and WPS, along with an unaffiliated utility, filed a request with the PSCW to acquire and construct Badger Hollow Wind and to acquire Whitetail, two utility-scale wind-powered electric generating facilities. If approved, Badger Hollow Wind will be located in Iowa and Grant counties, Wisconsin and Whitetail will be located in Grant County, Wisconsin. Once fully constructed, WE and WPS will collectively own 100 MWs of wind generation of Badger Hollow Wind and 60 MWs of wind generation of Whitetail. If approved, WE and WPS's combined share of the cost of Badger Hollow Wind is estimated to be $320 million and the cost of Whitetail is estimated to be approximately $200 million, with construction for both projects expected to be completed in 2027.

- In October 2024, WE and WPS, along with an unaffiliated utility, filed a request with the PSCW to acquire and construct Good Oak and Gristmill, two utility-scale solar electric generating facilities. If approved, both Good Oak and Gristmill will be located in Columbia County, Wisconsin. Once fully constructed, WE and WPS will collectively own 88 MWs of solar generation of Good Oak and 60 MWs of solar generation of Gristmill. If approved, WE and WPS's combined share of the cost of Good Oak is estimated to be $194 million and the cost of Gristmill is estimated to be approximately $130 million, with construction for both projects expected to be completed in 2028.

The construction of additional LNG facilities in Wisconsin has been proposed as part of our capital plan and would provide another approximately four Bcf of natural gas supply at an estimated cost of $940 million. The facilities are expected to reduce the likelihood of constraints on our natural gas distribution system during the highest demand days of winter.

As part of our capital plan, we plan to build additional natural gas-fired combustion turbines capable of producing approximately 675 MWs at an estimated cost of $960 million. In addition, we plan to add natural gas-fired RICE units that would be capable of producing approximately 114 MWs at an estimated cost of $250 million.

In connection with several investigations it conducted, the DOC set duties on solar panels and cells imported from four southeast Asian countries. See Factors Affecting Results, Liquidity, and Capital Resources – Regulatory, Legislative, and Legal Matters – United States Department of Commerce Complaints and Factors Affecting Results, Liquidity, and Capital Resources – Regulatory, Legislative, and Legal Matters – Uyghur Forced Labor Prevention Act for information on the duties set by the DOC and CBP actions, respectively. The expected in-service dates and costs identified above already reflect some of these impacts.

See Factors Affecting Results, Liquidity, and Capital Resources – Regulatory, Legislative, and Legal Matters – Renewable Energy Legislation for potential impacts to our capital projects as a result of the OBBBA.

In accordance with the November 2023 rate order, the ICC initiated a proceeding in January 2024 to determine the optimal method and a prudent investment level for replacing aging natural gas infrastructure. On February 20, 2025, the ICC issued an order setting expectations for PGL's prospective operations. For more information on regulatory proceedings related to this matter, see Note 23, Regulatory Environment, and Factors Affecting Results, Liquidity, and Capital Resources – Regulatory, Legislative, and Legal Matters – Illinois Proceedings.

The non-utility energy infrastructure line item in the table above includes WECI's investment in Hardin III, which closed in February 2025. See Note 2, Acquisitions, for more information on this project.

We expect to provide total capital contributions to ATC (not included in the above table) of approximately $445 million from 2025 through 2027. We do not expect to make any contributions to ATC Holdco during that period. WEC's portion of the investment in MISO Tranche 1 is estimated to be approximately $580 million between 2025 and 2029, a portion of which will be funded by ATC's cash from operations. 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

See Note 9, Long-Term Debt, for information regarding the changes in our outstanding long-term debt during the six months ended June 30, 2025.

Common Stock Dividends

Our current quarterly dividend rate is $0.8925 per share, which equates to an annual dividend of $3.57 per share. For information related to our most recent common stock dividend declared, see Note 7, Common Equity.

Other Significant Cash Requirements

See Note 21, Commitments and Contingencies, for information regarding our minimum future commitments related to purchase obligations for the procurement of fuel, power, and natural gas supply, as well as the related storage and transportation. There were no material changes to our other significant commitments outside the ordinary course of business during the six months ended June 30, 2025.

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. For additional information, see Note 8, Short-Term Debt and Lines of Credit, Note 15, Guarantees, and Note 20, Variable Interest Entities.

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, and common equity. Accessing the capital markets allows us to obtain external short-term borrowings, including commercial paper and term loans, and issue intermediate or long-term debt securities, as well as other types of securities. In 2024, we started issuing common equity through a combination of our employee benefit plans and stock purchase and dividend reinvestment plan, as well as through an at-the-market program. 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 financing 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.

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 for the remainder of 2025, 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 in our 2024 Annual Report on Form 10-K.

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, WEC Energy Group, 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 June 30, 2025, our current liabilities exceeded our current assets by $2,098.5 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 our 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 7, Common Equity, Note 8, Short-Term Debt and Lines of Credit, and Note 9, Long-Term Debt, for more information about our common stock activity, credit facilities, commercial paper, 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. These trusts have investments consisting of fixed income and equity securities that are subject to the volatility of the stock market and interest rates. For more information, see Investments in Outside Trusts in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Sources of Cash in our 2024 Annual Report on Form 10-K.

Capitalization Structure

The following table shows our capitalization structure as of June 30, 2025, as well as an adjusted capitalization structure that we believe is consistent with how a majority of the rating agencies currently view our 2024 Junior Notes:

(in millions)	Actual	Adjusted
Common shareholders' equity	$ 13,223.1	$ 13,598.1
Preferred stock of subsidiary	30.4	30.4
Long-term debt (including current portion)	19,360.8	18,985.8
Short-term debt	810.3	810.3
Total capitalization	$ 33,424.6	$ 33,424.6
Total debt	$ 20,171.1	$ 19,796.1
Ratio of debt to total capitalization	60.3 %	59.2 %

Included in long-term debt on our balance sheet as of June 30, 2025, was $750.0 million principal amount of WEC Energy Group's 2024 Junior Notes (2024A Junior Notes and 2024B Junior Notes, collectively) due 2055. The adjusted presentation attributes $375.0 million of the 2024 Junior Notes to common shareholders' equity and $375.0 million to long-term debt.

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 2024 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 June 30, 2025, 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 11, Common Equity, Note 13, Short-Term Debt and Lines of Credit, and Note 14, Long-Term Debt, in our 2024 Annual Report on Form 10-K, for more information regarding our debt covenants.

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 June 30, 2025. 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 June 30, 2025, it could have been required to post $106 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.

In March 2025, Moody's changed the rating outlook for PGL to stable from negative as a result of the ICC's order in February 2025 setting expectations for PGL's replacement of aging natural gas infrastructure. Moody's affirmed PGL's ratings, including its Aa3 senior secured rating and its P-1 short term rating for commercial paper. See Note 23, Regulatory Environment, for more information.

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

The following is a discussion of certain factors that may affect our results of operations, liquidity, and capital resources. This discussion should be read together with the information in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity, and Capital Resources in our 2024 Annual Report on Form 10-K, which provides a more complete discussion of factors affecting us, including market risks and other significant risks, competitive markets, environmental matters, critical accounting policies and estimates, and other matters.

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. 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 5, Regulatory Assets and Liabilities, for more information on our regulatory assets and liabilities. See Note 23, Regulatory Environment, in this report, and Note 26, Regulatory Environment, in our 2024 Annual Report on Form 10-K for more information regarding recent and pending rate proceedings, orders, and investigations involving our utilities.

Uncollectible Expense Adjustment Rider

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 required a $15.4 million and $0.7 million refund to ratepayers at PGL and NSG, respectively. These amounts were refunded over a period of nine months, which began on September 1, 2023. In July 2023, PGL and NSG petitioned the Illinois Appellate Court for review of the ICC order. In November 2024, the Illinois Appellate Court issued an opinion affirming the ICC order and the related disallowance. PGL and NSG subsequently petitioned the Illinois Supreme Court seeking review and reversal of the May 2023 order; however, their petition was denied in March 2025.

As of June 30, 2025, there can be no assurance that all costs incurred under the UEA rider during the open reconciliation years, which include 2019 through 2024, will be deemed recoverable by the ICC. The combined annual costs of PGL and NSG included in the rider, which reflect uncollectible write-offs in excess of what is recovered in base rates, have ranged from $10 million to $40 million during these open reconciliation years. Disallowances by the ICC, if any, could be material and have a material adverse impact on our results of operations.

Qualifying Infrastructure Plant Rider

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 August 2024, the ICC issued a final order on PGL's 2016 annual reconciliation, which included a disallowance of $14.8 million of certain capital costs. PGL recorded a pre-tax charge to income of $25.3 million during the third quarter of 2024 related to the disallowance and the previously recognized return on and of these investments. The charge was recorded on the income statement as a $12.9 million reduction in revenues for the amounts previously collected from customers, a $12.1 million increase to operating expenses for the impairment of PGL's property, plant, and equipment, and a $0.3 million increase to interest expense related to the amounts due to customers. In October 2024, PGL filed a petition with the Illinois Appellate Court for review of the ICC's August order.

PGL's QIP reconciliations from 2017 through 2023 are still pending. In July 2025, ICC staff and certain intervenors filed testimony with the ICC recommending significant disallowances in the 2017 QIP reconciliation proceeding. We believe that all costs were prudently incurred, but cannot predict the ultimate outcome of this matter. There is no statutory deadline by which the ICC is required to issue an order in this proceeding. The aggregate capital costs included in the rider during the open reconciliation years, along with any previously recognized return on these investments, totaled approximately $2.9 billion as of June 30, 2025. There can be no assurance that all of these costs and the previously recognized returns 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.

Illinois Proceedings

In the PGL rate order issued by the ICC in November 2023, the ICC ordered PGL to pause spending on its projects to upgrade its natural gas delivery system until the ICC completed 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 in January 2024. In February 2025, the ICC issued an order setting expectations for PGL's prospective operations. The ICC directed us to focus on replacing all cast and ductile iron pipe that has a diameter under 36 inches by January 1, 2035. The ICC also indicated that failure to comply with this directive could subject us to civil penalties under Illinois statute. PGL will replace this cast and ductile iron pipe through its PRP. Costs incurred under the PRP will be evaluated for prudency by the ICC in future rate cases. In addition, the program will be overseen by a safety monitor hired by the ICC. We are evaluating the impact of this order on our operations and capital plan.

In March 2024, the ICC initiated a statewide "Future of Gas" proceeding. The goal of this proceeding is 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 includes 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 includes a broad range of stakeholders, including Illinois utilities and other interested parties. The "Future of Gas" proceeding is expected to be completed in 2026. At this time, we cannot predict the ultimate outcome of this proceeding 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 outcome.

See Note 23, 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 in January 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.

Uyghur Forced Labor Prevention Act

In June 2022, the CBP implemented the UFLPA, which establishes a rebuttable presumption that certain silica-based products wholly or partially manufactured in the Xinjiang Uyghur Autonomous Region of China, such as polysilicon included in the manufacturing of solar panels, are prohibited from entering the United States. While our suppliers have been able to provide the CBP sufficient documentation to meet the UFLPA compliance requirements, and we expect the same will be true for subsequent projects, 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.

In January 2025, the Department of Homeland Security announced the addition of several more Chinese businesses to the UFLPA, including five solar supply chain providers. We are working to avoid doing business with these companies and remain in compliance with the UFLPA.

United States Department of Commerce Complaints

In August 2023, the DOC issued a final decision regarding an AD/CVD petition filed by a California-based company finding that Chinese manufacturers were shifting products to four Southeast Asian countries to avoid tariffs required on products imported from China. The DOC applied duties to certain imports of solar cells from Malaysia, Vietnam, Thailand and Cambodia, starting on June 6, 2024. In addition, in response to its findings, the DOC promulgated new regulations that imposed enhanced duties in certain circumstances, including when the USITC determines there is a reasonable indication the domestic solar industry is materially or potentially injured because of imported products that violate certain fair trade laws.

In April 2024, a coalition of several U.S. producers of solar panels filed a new petition with the DOC requesting tariffs on imports from the same four Southeast Asian countries. The group alleged that some Chinese companies had moved their solar operations to avoid penalties. In response to the petition, the DOC and USITC initiated new AD/CVD investigations of solar panels from the four Southeast Asian countries to determine whether there was a reasonable indication imports of such solar panels were causing injury to the U.S. solar industry. Based on the USITC's preliminary affirmative determination, the DOC began AD/CVD investigations and, in the fall of 2024, announced preliminary affirmative determinations and set preliminary duties on imports from the four Southeast Asian countries. In April 2025, the DOC announced its final affirmative determinations in its AD/CVD investigations, increasing the preliminary tariff rates, in some cases significantly. These increased rates became effective and enforceable in May 2025 upon the USITC's final affirmative determination. As a result of these duties, the cost and availability of solar panels in the U.S. has been impacted and the U.S. solar industry overall has experienced higher costs of materials as well as delays. Some of these impacts have already been reflected in the estimated cost and in-service dates for certain of our solar projects.

On July 17, 2025, a coalition of trade groups filed new AD/CVD petitions with the USITC and the DOC, asking for investigations into alleged illegal trade practices by largely Chinese-owned manufacturers operating in Laos and Indonesia, as well as companies headquartered in India. Affirmative findings could cause further strain on the solar panel industry. We are monitoring the status of these petitions.

Renewable Energy Legislation

Infrastructure Investment and Jobs Act and Inflation Reduction Act

In November 2021, the Infrastructure Investment and Jobs Act was signed into law and 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 believe that funding from this Act would support the work we are doing to reduce GHG emissions, increase EV charging, and strengthen and protect the energy grid. Funding in the Act could also help to expand emerging technologies, like hydrogen and carbon management, as we continue the transition to a clean energy future to the benefit of our customers, the communities we serve, and our company.

In August 2022, the IRA was signed into law and 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 the IRA transferability option, we entered into agreements in October 2024 and April 2025 to sell the majority of the PTCs we generated in 2025 and 2026, respectively, to third parties. In May 2025, we entered into an agreement to sell the majority of our remaining unsold PTCs we generated in 2024 to a third party. See Note 12, 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.

In January 2025, pursuant to an executive order issued by the current presidential administration, disbursement of funds under these two Acts was paused until agency heads can determine whether grants, loans, contracts, and other disbursements are consistent with the current administration's energy policy. Agency heads must consult with the Office of Management and Budget and the National Economic Council prior to any funding being disbursed. The new policy encourages use of domestic energy sources including oil, natural gas, coal, hydropower, biofuels, critical minerals, and nuclear, promotes consumer choice of goods and appliances, aims to boost American workers and businesses, eliminates the EV mandate, and limits regulations that apply to the energy industry. The pause could disrupt funding, temporarily or permanently, for infrastructure projects already in progress, may cause project delays and cancellations, may impact continuing payment obligations for downstream contractors and suppliers, and may cause legal and contractual claims. The executive order did not impact the IRA's provisions for tax credits and the transferability option.

One Big Beautiful Bill Act

On July 4, 2025, the OBBBA was signed into law, enacting significant modifications to clean-energy tax credits previously provided under the IRA. The OBBBA provides companies the ability to earn solar and wind tax credits at current credit rates if construction of projects begins by July 4, 2026, and the projects are placed in-service within four years after beginning construction. However, wind and solar projects that begin construction more than one year after enactment of the OBBBA must be placed in service by December 31, 2027 to qualify for PTCs and ITCs. In addition, wind and solar projects that begin construction after December 31, 2025 must also satisfy prohibited foreign entity material assistance requirements. The phase out of PTCs and ITCs does not apply to energy storage, hydroelectric facilities, nuclear, or any other zero emission technology. The OBBBA preserves the ability to transfer tax credits, with the exception of transfers to a prohibited foreign entity. On July 7, 2025, an executive order was issued by the presidential administration directing the Secretary of the Treasury to strictly enforce the termination of PTCs and ITCs for wind and solar facilities and to issue updated guidance within 45 days to clarify and tighten the beginning of construction rules for energy projects, as directed in the OBBBA. We continue to assess the potential impacts of the OBBBA and the related executive order.

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 $8 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 LLC Allowed Return on Equity Complaint

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 a complaint was 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 ROE complaint section 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.

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.

- September 2016 FERC 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 this complaint, November 12, 2013 through February 11, 2015 and September 28, 2016 going forward.

- November 2019 FERC 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 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 FERC 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 complaint. Various parties then filed requests to rehear certain parts of the May 2020 Order with the FERC.

- November 2020 FERC 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 for FERC Orders Issued Prior to October 2024 – Due to the base ROE changes resulting from the FERC orders issued prior to October 2024, 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 these periods. The refunds were applied to WE's and WPS's PSCW-approved escrow accounting for transmission expense.

- August 2022 D.C. Circuit Court of Appeals Opinion – 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 Opinion, 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 a result, ATC recorded a reserve for potential refunds based on a 9.88% base ROE.

- October 2024 FERC Order – In response to the August 2022 D.C. Circuit Court of Appeals Opinion, the FERC issued an order on October 17, 2024. The FERC’s October 2024 Order removed the risk premium model from the base ROE methodology and required MISO transmission owners, including ATC, to adopt a 9.98% base ROE for the period covered by the complaint.

- Refunds for FERC Order Issued in October 2024 – Prior to the October 2024 FERC order, the base ROE for MISO transmission owners was 10.02% based on the November 2020 FERC order. Since the October 2024 FERC order changed the base ROE to 9.98%, ATC is providing additional 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 October 17, 2024. As a result, WE, WPS, and UMERC are receiving refunds from ATC related to the transmission costs they paid during these two refund periods. The refunds are being applied to WE’s and WPS’s PSCW-approved escrow accounting for transmission expense.

  Due to the change between the 9.88% base ROE originally reflected in ATC's reserve and the 9.98% base ROE authorized in the October 2024 FERC Order, ATC reduced its refund liability, which increased our pre-tax equity earnings, by $20.1 million during the fourth quarter of 2024.

- March 2025 FERC Order – In response to rehearing requests filed concerning the October 2024 FERC Order, the FERC issued an order on March 25, 2025 that reaffirmed the October 2024 FERC Order in its entirety. Appeals related to the October 2024 FERC Order are still pending before the D.C. Circuit Court of Appeals.

Environmental Matters

See Note 21, Commitments and Contingencies, for a discussion of certain environmental matters affecting us, including rules and regulations relating to air quality, water quality, land quality, and climate change.

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 include, but are not limited to, the risks described below. In addition, there is continuing uncertainty over the impact that the ongoing regional conflicts, including those in Ukraine, Israel and in other parts of the Middle East, will ultimately have on the global economy, supply chains, and fuel prices. 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 in our 2024 Annual Report on Form 10-K for a discussion of market and other significant risks applicable to us.

Changes to United States Trade Policy (Tariff Activity)

The U.S. continues to implement changes to its international trade policy including changes to tariffs, port fees and other policies relating to exports from and imports into the United States. In response to these changes, foreign governments are also adjusting their trade policies, including the imposition of additional tariffs. There remains significant uncertainty as to the ultimate scope of the U.S. and foreign trade policies. Both the U.S. and foreign trade policy changes could increase the cost of materials or disrupt supply chains, which could impact our ability to repair or maintain our infrastructure; the timing, cost or completion of our infrastructure projects; and/or our ability to execute our capital plan. In addition, these changes, including any impact they may have to economic conditions, could lead to reduced energy demand by our customers. Consequently, these policy changes could have a material adverse effect on our business, results of operations and financial condition.

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 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 that are disclosed in Part I of our 2024 Annual Report on Form 10-K.

- 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 – The fluctuation in demand for certain commodities and their respective prices could negatively impact our operations.

For additional information concerning risk factors, including market risks, see the Cautionary Statement Regarding Forward-Looking Information at the beginning of this report.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

There have been no material changes related to market risk from the disclosures presented in our 2024 Annual Report on Form 10-K. In addition to the Form 10-K disclosures, see 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 in Item 2 of Part I of this report, as well as Note 13, Fair Value Measurements, Note 14, Derivative Instruments, and Note 15, Guarantees, in this report for information concerning our market risk exposures.

ITEM 4. 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.

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 second quarter of 2025 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

The following should be read in conjunction with Item 3. Legal Proceedings in Part I of our 2024 Annual Report on Form 10-K. See Note 21, Commitments and Contingencies, and Note 23, 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 21, Commitments and Contingencies, and Note 23, Regulatory Environment, 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.

ITEM 1A. RISK FACTORS

There were no material changes from the risk factors disclosed in Item 1A. Risk Factors in Part I of our 2024 Annual Report on Form 10-K.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table sets forth information regarding the purchases of our equity securities made by or on behalf of us or any affiliated purchaser (as defined in Exchange Act Rule 10b-18) during the three months ended June 30, 2025:

Issuer Purchases of Equity Securities

2025	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
April 1 – April 30	289	$ 108.64	—	$ —
May 1 – May 31	—	—	—	—
June 1 – June 30	—	—	—	—
Total [1]	**289**	**$ 108.64**	—	

[1] All shares were surrendered by employees to satisfy tax withholding obligations upon vesting of restricted stock.

ITEM 5. OTHER INFORMATION

During the three months ended June 30, 2025, 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).

Table of Contents

ITEM 6. EXHIBITS

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.

Number	Exhibit	
4	**Instruments Defining the Rights of Security Holders, Including Indentures**	
	4.1*	Indenture dated June 10, 2025, between WEC Energy Group (as Issuer) and The Bank of New York Mellon Trust Company, N.A. (as Trustee). (Exhibit 4.1 to WEC Energy Group's Form 8-K filed June 10, 2025.) (File No. 1-09057.)
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.
101	**Interactive Data Files**	
	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 Data File (formatted as Inline XBRL and contained in Exhibit 101)**	

SIGNATURE

Pursuant to the requirements 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.
(Registrant)

/s/ WILLIAM J. GUC

Date: August 1, 2025

William J. Guc
Vice President and Controller

(Duly Authorized Officer and Chief Accounting Officer)

Exhibit 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

I, Scott J. Lauber, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of WEC Energy Group, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an Annual Report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2025

/s/ SCOTT J. LAUBER
Scott J. Lauber
President and Chief Executive Officer
(Principal Executive Officer)

Certification Pursuant to
Rule 13a-14(a) or 15d-14(a),
as Adopted Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Xia Liu, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of WEC Energy Group, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an Annual Report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 1, 2025

/s/ XIA LIU

Xia Liu
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

**Certification Pursuant to
18 U.S.C. Section 1350,
As Adopted Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002**

In connection with the Quarterly Report of WEC Energy Group, Inc. (the "Company") on Form 10-Q for the quarter ended June 30, 2025, as filed with the Securities and Exchange Commission on August 1, 2025 (the "Report"), I, Scott J. Lauber, President and Chief Executive Officer of the Company, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ SCOTT J. LAUBER

Scott J. Lauber
President and Chief Executive Officer
August 1, 2025

Exhibit 32.2

Certification Pursuant to
18 U.S.C. Section 1350,
As Adopted Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Quarterly Report of WEC Energy Group, Inc. (the "Company") on Form 10-Q for the quarter ended June 30, 2025, as filed with the Securities and Exchange Commission on August 1, 2025 (the "Report"), I, Xia Liu, Executive Vice President and Chief Financial Officer of the Company, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ XIA LIU

Xia Liu
Executive Vice President and Chief Financial Officer
August 1, 2025