WEC ENERGY GROUP, INC.
Form 10-K
February 26, 2019

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

FORM 10-K

(Mark One)
[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2018

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	Name of Each Exchange on Which Registered
Common Stock, $.01 Par Value	New York Stock Exchange

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

None

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes [X] No [ ]

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes [ ] No [X]

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 [X]   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 [X]   No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

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 [X]	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 [X]

The aggregate market value of the common stock of WEC Energy Group, Inc. held by non-affiliates was $20.4 billion based upon the reported closing price of such securities as of June 30, 2018.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date (January 31, 2019):

Common Stock, $.01 par value, 315,455,323 shares outstanding

Documents incorporated by reference:

Portions of WEC Energy Group, Inc.'s Definitive Proxy Statement on Schedule 14A for its Annual Meeting of Shareholders, to be held on May 2, 2019, are incorporated by reference into Part III hereof.

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For the Year Ended December 31, 2018
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GLOSSARY OF TERMS AND ABBREVIATIONS

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

Subsidiaries and Affiliates

ATC	American Transmission Company LLC
ATC Holdco	ATC Holdco, LLC
ATC Holding	ATC Holding LLC
Bishop Hill III	Bishop Hill Energy III LLC
Bluewater	Bluewater Natural Gas Holding, LLC
Bluewater Gas Storage	Bluewater Gas Storage, LLC
Bostco	Bostco LLC
Coyote Ridge	Coyote Ridge Wind, LLC
Integrys	Integrys Holding, Inc.
ITF	Integrys Transportation Fuels, LLC
MERC	Minnesota Energy Resources Corporation
MGU	Michigan Gas Utilities Corporation
NSG	North Shore Gas Company
PDL	WPS Power Development, LLC
PELLC	Peoples Energy, LLC
PGL	The Peoples Gas Light and Coke Company
UMERC	Upper Michigan Energy Resources Corporation
Upstream	Upstream Wind Energy LLC
WBS	WEC Business Services LLC
WE	Wisconsin Electric Power Company
We Power	W.E. Power, LLC
WEC Energy Group	WEC Energy Group, Inc.
WECC	Wisconsin Energy Capital Corporation
WG	Wisconsin Gas LLC
Wispark	Wispark LLC
Wisvest	Wisvest LLC
WPS	Wisconsin Public Service Corporation
WRPC	Wisconsin River Power Company

Federal and State Regulatory Agencies

EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
ICC	Illinois Commerce Commission
IRS	United States Internal Revenue Service
MDEQ	Michigan Department of Environmental Quality
MPSC	Michigan Public Service Commission
MPUC	Minnesota Public Utilities Commission
PSCW	Public Service Commission of Wisconsin
SEC	Securities and Exchange Commission
WDNR	Wisconsin Department of Natural Resources

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Accounting Terms

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

Environmental Terms

ACE	Affordable Clean Energy
Act 141	2005 Wisconsin Act 141
CAA	Clean Air Act
CO_2	Carbon Dioxide
CPP	Clean Power Plan
GHG	Greenhouse Gas
NAAQS	National Ambient Air Quality Standards
NOV	Notice of Violation
NOx	Nitrogen Oxide
SO_2	Sulfur Dioxide
WPDES	Wisconsin Pollutant Discharge Elimination System

Measurements

Dth	Dekatherm
MDth	One thousand Dekatherms
MW	Megawatt
MWh	Megawatt-hour

Other Terms and Abbreviations

2006 Junior Notes	Integrys's 2006 Junior Subordinated Notes Due 2066
2007 Junior Notes	WEC Energy Group, Inc.'s 2007 Junior Subordinated Notes Due 2067
ALJ	Administrative Law Judge
ARR	Auction Revenue Right
CNG	Compressed Natural Gas
Compensation Committee	Compensation Committee of the Board of Directors
DATC	Duke-American Transmission Company
D.C. Circuit Court of Appeals	United States Court of Appeals for the District of Columbia Circuit
ERGS	Elm Road Generating Station
ER 1	Elm Road Generating Station Unit 1
ER 2	Elm Road Generating Station Unit 2
Exchange Act	Securities Exchange Act of 1934, as amended
FTR	Financial Transmission Right
GCRM	Gas Cost Recovery Mechanism
LMP	Locational Marginal Price
MCPP	Milwaukee County Power Plant
MISO	Midcontinent Independent System Operator, Inc.
MISO Energy Markets	MISO Energy and Operating Reserves Market

NYMEX	New York Mercantile Exchange
OCPP	Oak Creek Power Plant
OC 5	Oak Creek Power Plant Unit 5

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OC 6	Oak Creek Power Plant Unit 6
OC 7	Oak Creek Power Plant Unit 7
OC 8	Oak Creek Power Plant Unit 8
Omnibus Stock Incentive Plan	WEC Energy Group 1993 Omnibus Stock Incentive Plan, Amended and Restated Effective as of January 1, 2016
PIPP	Presque Isle Power Plant
Point Beach	Point Beach Nuclear Power Plant
PWGS	Port Washington Generating Station
PWGS 1	Port Washington Generating Station Unit 1
PWGS 2	Port Washington Generating Station Unit 2
QIP	Qualifying Infrastructure Plant
ROE	Return on Equity
RTO	Regional Transmission Organization
SMP	Natural Gas System Modernization Program
SMRP	System Modernization and Reliability Project
SSR	System Support Resource
Supreme Court	United States Supreme Court
Tax Legislation	Tax Cuts and Jobs Act of 2017
Tilden	Tilden Mining Company
VAPP	Valley Power Plant
VITA	Variable Income Tax Adjustment Rider

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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 and 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, environmental matters, liquidity and capital resources, and other matters.

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

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

- Factors affecting the demand for electricity and natural gas, including political developments, unusual weather, changes in economic conditions, customer growth and declines, commodity prices, energy conservation efforts, and continued adoption of distributed generation by customers;

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

- The 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, as well as the recovery of the related costs through rates;

- The impact of federal, state, and local legislative and/or regulatory changes, including changes in rate-setting policies or procedures, 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, and tax laws that affect our ability to use production tax credits and investment tax credits;

- The remaining uncertainty surrounding the Tax Legislation enacted in December 2017, including implementing regulations and IRS interpretations, the amount to be returned to our ratepayers, and any further impact on our and our subsidiaries' credit ratings;

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

- Factors affecting the implementation of our generation reshaping plan, including related regulatory decisions, the cost of materials, supplies, and labor, and the feasibility of competing projects;

- Increased pressure on us by investors and other stakeholder groups to take more aggressive action to reduce future GHG emissions in order to limit future global temperature increases;

- The risks associated with changing commodity prices, particularly natural gas and electricity, and the availability of sources of fossil fuel, natural gas, purchased power, materials needed to operate environmental controls at our electric generating facilities,

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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;

- 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;
- 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 direct or indirect effect on our business resulting from terrorist attacks and cyber security 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;
- The financial performance of ATC and its corresponding contribution to our earnings, as well as the ability of ATC and DATC to obtain the required approvals for their transmission projects;
- 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;
- The risk associated with the values of goodwill and other intangible assets and their possible impairment;
- Potential business strategies to acquire and dispose of assets or businesses, 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 ability to maintain effective internal controls in accordance with Section 404 of the Sarbanes-Oxley Act, while both integrating and continuing to consolidate our enterprise systems;
- 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.

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.

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PART I

ITEM 1. BUSINESS

A. INTRODUCTION

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

For more information about our business operations, see Note 20, Segment Information, and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations.

WEC Energy Group, Inc.

We were incorporated in the state of Wisconsin in 1981 and became a diversified holding company in 1986. We maintain our principal executive offices in Milwaukee, Wisconsin. On June 29, 2015, we acquired 100% of the outstanding common shares of Integrys and changed our name to WEC Energy Group, Inc. Our wholly owned subsidiaries provide regulated natural gas and electricity, as well as nonregulated renewable energy. Another subsidiary, ITF, provided CNG products and services prior to its sale in the first quarter of 2016. See Note 3, Dispositions, for more information on this sale. We have an approximately 60% equity interest in ATC (an electric transmission company operating in Illinois, Michigan, Minnesota, and Wisconsin). At December 31, 2018, we had six reportable segments, which are discussed below. For additional information about our reportable segments, see Note 20, Segment Information.

Available Information

Our annual and periodic filings with the SEC are available, free of charge, on our website, www.wecenergygroup.com, as soon as reasonably practicable after they are filed with or furnished to the SEC. You may also obtain materials we filed with or furnished to the SEC on their website at www.sec.gov.

B. UTILITY ENERGY OPERATIONS

Wisconsin Segment

The Wisconsin segment includes the electric and natural gas utility operations of WE, WG, WPS, and UMERC, which includes WE's former electric operations and WPS's former electric and natural gas operations in the state of Michigan that were transferred to UMERC effective January 1, 2017.

In December 2016, both the MPSC and the PSCW approved the operation of UMERC as a stand-alone utility in the Upper Peninsula of Michigan. See Note 24, Regulatory Environment, for more information. UMERC became operational effective January 1, 2017, and WE and WPS transferred customers and property, plant, and equipment as of that date. WE transferred approximately 27,500 retail electric customers and 50 electric distribution-only customers to UMERC, along with approximately 2,500 miles of electric distribution lines. WPS transferred approximately 9,000 retail electric customers and 5,300 natural gas customers to UMERC, along with approximately 600 miles of electric distribution lines and approximately 100 miles of natural gas distribution mains. WE and WPS also transferred related electric distribution substations in the Upper Peninsula of Michigan and all property rights for the distribution assets to UMERC. The book value of net assets, including the related deferred income tax liabilities, transferred to UMERC from WE and WPS as of January 1, 2017, was $61.1 million and $20.6 million, respectively. This transaction was a non-cash equity transfer recorded to additional paid in capital between entities under common control, and therefore, did not result in the recognition of a gain or loss.

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Electric Utility Operations

For the periods presented in this Annual Report on Form 10-K, our electric utility operations included operations of WE and WPS for all periods, and operations for UMERC beginning January 1, 2017, due to the transfer of customers and assets located in the Upper Peninsula of Michigan from WE and WPS.

- WE, which is the largest electric utility in the state of Wisconsin, generates and distributes electric energy to customers located in southeastern Wisconsin (including the metropolitan Milwaukee area), east central Wisconsin, and northern Wisconsin, and serves an iron ore mine customer, Tilden, in the Upper Peninsula of Michigan. This customer will become a customer of UMERC once the new generation solution in the Upper Peninsula of Michigan begins commercial operation, which is expected to occur during the second quarter of 2019.

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

- UMERC distributes electric energy to customers located in the Upper Peninsula of Michigan. UMERC currently meets its market obligations through power purchase agreements with WE and WPS. UMERC will begin to generate electricity when its new generation solution in the Upper Peninsula of Michigan begins commercial operation. For more information on UMERC's new generation solution, see the discussion below under the heading "Natural Gas-Fired Generation."

Operating Revenues

The following table shows electric utility operating revenues, including steam operations. For information about our operating revenues disaggregated by customer class for the year ended December 31, 2018, see Note 4, Operating Revenues. For more information about our significant accounting policies related to the recognition of revenues, see Note 1(d), Operating Revenues.

	Year Ended December 31	
(in millions)	2017	2016
Operating revenues		
Residential	$1,581.5	$1,620.7
Small commercial and industrial (1)	1,400.9	1,418.1
Large commercial and industrial (1)	913.7	949.5
Other	30.5	29.8
Retail (1)	3,926.6	4,018.1
Wholesale	233.4	231.2
Resale	270.6	247.1
Steam	23.3	27.2
Other operating revenues (2)	105.1	104.5
Total operating revenues (1)	$4,559.0	$4,628.1

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

(2) Includes SSR revenues, amounts collected from (refunded to) customers for certain fuel and purchased power costs that exceed a 2% price variance from costs included in rates, and other revenues, partially offset by revenues from Tilden that are being deferred until a future rate proceeding. For more information, see the discussion below under the heading "Large Electric Retail Customers."

Electric Sales

Our electric energy deliveries included supply and distribution sales to retail and wholesale customers and distribution sales to those customers who switched to an alternative electric supplier. In 2018, retail electric revenues accounted for 90.0% of total electric operating revenues, while wholesale and resale electric revenues accounted for 9.1% of total electric operating revenues. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Wisconsin Segment Contribution to Operating Income for information on MWh sales by customer class.

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

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

Steam Sales

WE has a steam utility that generates, distributes, and sells steam supplied by VAPP to customers in metropolitan Milwaukee, Wisconsin. Steam is used by customers for processing, space heating, domestic hot water, and humidification. Annual sales of steam fluctuate from year to year based on system growth and variations in weather conditions. In April 2016, we sold the MCPP steam generation and distribution assets, located in Wauwatosa, Wisconsin. MCPP primarily provided steam to the Milwaukee Regional Medical Center hospitals and other campus buildings. See Note 3, Dispositions, for more information.

Electric Sales Forecast

Our service territories experienced growth in weather-normalized retail electric sales in 2018 due to customer growth. We currently forecast retail electric sales volumes and the associated peak demand, excluding the Tilden mine located in the Upper Peninsula of Michigan, to grow between flat and 0.5% over the next five years, assuming normal weather.

Customers

	Year Ended December 31		
(in thousands)	2018	2017	2016
Electric customers – end of year			
Residential	1,441.3	1,431.4	1,421.7
Small commercial and industrial	173.2	172.2	171.1
Large commercial and industrial	0.9	0.9	0.9
Other	2.7	2.6	2.6
Total electric customers – end of year	1,618.1	1,607.1	1,596.3
Steam customers – end of year	0.4	0.4	0.4

Large Electric Retail Customers

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

In February 2015, Tilden, along with another affiliated iron ore mine located in the Upper Peninsula of Michigan, returned as customers after choosing an alternative electric supplier in September 2013. For more information on alternative electric suppliers, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity, and Capital Resources – Competitive Markets. WE entered into a contract with each of the mines to provide full requirements electric service through December 31, 2019. Since 2015, we have been deferring, and expect to continue to defer, the revenues less costs of sales from the mine sales and will apply these amounts for the benefit of Wisconsin retail electric customers in a future rate proceeding, as ordered by the PSCW.

In 2016, one of the iron ore mines closed, and the related contract for full requirements electric service was terminated. In August 2016, we entered into a new agreement with Tilden under which it will purchase electric power from UMERC for 20 years for the remaining mine, contingent upon UMERC's construction of natural gas-fired generation in the Upper Peninsula of Michigan. Tilden will continue to receive full requirements electric service from WE under the existing contract until UMERC's generation solution in the Upper Peninsula of Michigan begins commercial operation, which is expected to occur during the second quarter of 2019. See Note 24, Regulatory Environment, for more information, as well as the discussion under the heading "Natural Gas-Fired Generation" below.

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Wholesale Customers

We provide wholesale electric service to various customers, including electric cooperatives, municipal joint action agencies, other investor-owned utilities, municipal utilities, and energy marketers. Wholesale sales accounted for 7.7%, 7.6%, and 7.4% of total electric energy sales volumes during 2018, 2017, and 2016, respectively. Wholesale revenues accounted for 4.8%, 5.1%, and 5.0% of total electric operating revenues during 2018, 2017, and 2016, respectively.

Resale

The majority of our sales for resale are sold into an energy market operated by MISO at market rates based on availability of our generation and market demand. Resale sales accounted for 12.8%, 18.2%, and 17.5% of total electric energy sales volumes during 2018, 2017, and 2016, respectively. Resale revenues accounted for 4.3%, 5.9%, and 5.3% of total electric operating revenues during 2018, 2017, and 2016, respectively. Retail fuel costs are reduced by the amount that revenue exceeds the costs of sales derived from these opportunity sales.

Electric Generation and Supply Mix

Our electric supply strategy is to provide our customers with energy from plants using a diverse fuel mix that is expected to maintain a stable, reliable, and affordable supply of electricity. Through our participation in the MISO Energy Markets, we supply a significant amount of electricity to our customers from power plants that we own. We supplement our internally generated power supply with long-term power purchase agreements, including the Point Beach power purchase agreement discussed under the heading "Power Purchase Commitments," and through spot purchases in the MISO Energy Markets. We also sell excess capacity into the MISO Energy Markets when it is economical, which reduces net fuel costs by offsetting costs of purchased power.

Our rated capacity by fuel type as of December 31 is shown below. For more information on our electric generation facilities, see Item 2. Properties.

	Rated Capacity in MW (1)		
	2018	2017	2016
Coal	3,518	4,935	4,933
Natural gas:			
Combined cycle	1,799	1,753	1,697
Steam turbine (2)	347	314	320
Natural gas/oil peaking units (3)	1,444	1,458	1,413
Renewables (4)	220	273	273
Total rated capacity	7,328	8,733	8,636

(1) Rated capacity is the net power output under average operating conditions with equipment in an average state of repair as of a given month in a given year. We have summer peaking electric utilities, and amounts are primarily based on expected capacity ratings for the following summer. The values were established by tests and may change slightly from year to year.

(2) The natural gas steam turbine represents the rated capacity associated with VAPP as well as Weston Unit 2.

(3) Certain dual-fueled facilities generally burn oil only if natural gas is not available due to constraints on the natural gas pipeline and/or at the local natural gas distribution company that delivers natural gas to the plants.

(4) Includes hydroelectric, biomass, and wind generation.

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The table below indicates our sources of electric energy supply as a percentage of sales for the three years ended December 31, as well as estimates for 2019:

	Estimate 2019	Actual 2018	2017	2016
Company-owned generation units:				
Coal *	35.9 %	44.7 %	48.5 %	45.7 %
Natural gas:				
Combined cycle	23.9 %	19.7 %	16.5 %	18.2 %
Steam turbine	0.8 %	0.6 %	0.8 %	0.9 %
Natural gas/oil peaking units	1.1 %	1.7 %	1.1 %	1.1 %
Renewables	4.2 %	4.1 %	4.1 %	3.9 %
Total company-owned generation units	65.9 %	70.8 %	71.0 %	69.8 %
Power purchase contracts:				
Nuclear	19.0 %	18.6 %	17.7 %	17.5 %
Natural gas	3.0 %	1.5 %	1.3 %	1.7 %
Renewables	3.1 %	2.4 %	2.9 %	2.8 %
Other	1.8 %	1.7 %	1.6 %	2.1 %
Total power purchase contracts	26.9 %	24.2 %	23.5 %	24.1 %
Purchased power from MISO	7.2 %	5.0 %	5.5 %	6.1 %
Total purchased power	34.1 %	29.2 %	29.0 %	30.2 %
Total electric utility supply	100.0 %	100.0 %	100.0 %	100.0 %

* Although the generation of PIPP has been included as a source of our electric energy supply for the three years ended December 31, we have only included this generation facility as a source of our estimated 2019 electric energy supply through its expected retirement date on or before May 31, 2019. See Note 6, Property, Plant, and Equipment, for more information.

Reshaping our Generation Fleet

The following discussion summarizes information about our generation facilities, including the planned reshaping of our generation fleet to balance reliability and customer cost with environmental stewardship. Generation reshaping includes retiring older fossil fuel generation units, building state-of-the-art natural gas generation, and investing in cost-effective zero-carbon generation with a goal of reducing CO_2 emissions by approximately 40% and 80% below 2005 levels by 2030 and 2050, respectively.

Coal-Fired Generation

As of December 31, 2018, our coal-fired generation consists of five operating plants with a rated capacity of 3,518 MW. For more information about our operating plants, see Item 2. Properties.

We plan to retire approximately 1,800 MW of coal-fired generation by 2020 as a result of WEC Energy Group's generation reshaping plan. As part of this effort during 2018, we retired approximately 1,500 MW of coal-fired generation, including the Pleasant Prairie power plant, Pulliam power plant, and the jointly-owned Edgewater Unit 4. We are required to retire PIPP by May 31, 2019. For more information about the retirement of these plants, see Note 6, Property, Plant, and Equipment.

Natural Gas-Fired Generation

Our natural gas-fired generation currently consists of nine operating plants, including peaking units, with a rated capacity of 3,400 MW as of December 31, 2018. For more information about our operating plants, see Item 2. Properties.

In October 2017, the MPSC approved UMERC's application for a certificate of necessity to begin construction of a long-term generation solution for electric reliability in the region. UMERC is constructing and will operate approximately 180 MW of natural gas-fired generation in the Upper Peninsula of Michigan. The new generation is expected to begin commercial operation during the second quarter of 2019. See Note 24, Regulatory Environment, for more information.

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Oil-Fired Generation

Our oil-fired generation had a rated capacity of 190 MW as of December 31, 2018. We also have natural gas-fired peaking units with a rated capacity of 1,239 MW, which have the ability to burn oil if natural gas is not available due to delivery constraints. For more information about our operating plants, see Item 2. Properties.

Renewable Generation

Our electric utilities meet a portion of their electric generation supply with various renewable energy resources. This helps our electric utilities maintain compliance with renewable energy legislation in Wisconsin and Michigan. These renewable energy resources also help us maintain diversity in our generation portfolio, which effectively serves as a price hedge against future fuel costs, and will help mitigate the risk of potential unknown costs associated with any future carbon restrictions for electric generators. For more information about our renewable generation, see Item 2. Properties.

In December 2018, WE received approval from the PSCW for the Dedicated Renewable Energy Resource pilot program, a program for customers who wish to access a large-scale renewable project located in Wisconsin that WE would operate. The project will contribute toward meeting WE's peak demand, adding up to 150 MW of renewables to WE's portfolio.

Solar

As part of our commitment to invest in zero-carbon generation, we plan to invest in utility scale solar of up to 350 MW within our Wisconsin segment. In May 2018, WPS, along with an unaffiliated utility, filed an application with the PSCW for approval to acquire ownership interests in two proposed solar projects in Wisconsin. Badger Hollow Solar Farm will be located in Iowa County, Wisconsin, and Two Creeks Solar Project will be located in Manitowoc County, Wisconsin. If approved, WPS will own 100 MW of the output of each project for a total of 200 MW.

In December 2018, WE received approval from the PSCW for the Solar Now pilot program, which is expected to add 35 MW of renewables to WE's portfolio and will allow commercial and industrial customers to site solar arrays on their property.

Hydroelectric

Our hydroelectric generating system consists of 30 operating plants with a total installed capacity of 173 MW and a rated capacity of 102 MW as of December 31, 2018. All of our hydroelectric facilities follow FERC guidelines and/or regulations.

Wind

We have six wind sites, consisting of 352 turbines, with an installed capacity of 576 MW and a rated capacity of 72 MW as of December 31, 2018. In April 2018, WPS, along with two other non-affiliated utilities, completed the purchase of Forward Wind Energy Center, which consists of 86 wind turbines located in Wisconsin with a total capacity of 138 MW. WPS’s proportionate share of Forward Wind Energy Center is 44.6%. See Note 2, Acquisitions, for more information.

Biomass

We have a biomass-fueled power plant at a Rothschild, Wisconsin paper mill site. Wood waste and wood shavings are used to produce a rated capacity of approximately 46 MW of electric power as well as steam to support the paper mill's operations. Fuel for the power plant is supplied by both the paper mill and through contracts with biomass suppliers. The plant also has the ability to burn natural gas if wood waste and wood shavings are not available.

Electric System Reliability

The PSCW requires us to maintain a planning reserve margin above our projected annual peak demand forecast to help ensure reliability of electric service to our customers. These planning reserve requirements are consistent with the MISO calculated planning reserve margin. In 2008, the PSCW established a 14.5% reserve margin requirement for long-term planning (planning years two through ten). For short-term planning (planning year one), the PSCW requires Wisconsin utilities to follow the planning reserve margin established by MISO. MISO has a 17.1% installed capacity reserve margin requirement for the planning year from June 1, 2018, through May 31, 2019, and a 16.8% installed capacity reserve margin requirement for the planning year from June 1, 2019,

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through May 31, 2020. MISO's short-term reserve margin requirements experience year-to-year fluctuations, primarily due to changes in the average forced outage rate of generation within the MISO footprint.

Michigan legislation requires all electric providers to demonstrate to the MPSC that they have enough resources to serve the anticipated needs of their customers for a minimum of four consecutive planning years beginning in the upcoming planning year June 1, 2019, through May 31, 2020. The MPSC has established future planning reserve margin requirements based on the same study conducted by MISO that determines the short-term reserve margin requirements.

In both of our Wisconsin and Michigan jurisdictions, we have adequate capacity through company-owned generation units and power purchase contracts to meet the MISO calculated planning reserve margin during the current planning year. We also fully anticipate that we will have adequate capacity to meet the planning reserve margin requirements for the upcoming planning year in both jurisdictions. However, extremely hot weather, unexpected equipment failure, or unavailability across the 15-state MISO footprint could require us to call upon load management procedures. Load management procedures allow for the reduction of energy use through agreements with customers to directly shut off their equipment or through interruptible service, where customers agree to reduce their load in the case of an emergency interruption.

Fuel and Purchased Power Costs

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

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

	2018	2017	2016
Coal	$23.54	$23.05	$23.09
Natural gas combined cycle	21.69	22.65	18.79
Natural gas/oil peaking units	49.06	53.91	45.08
Biomass	97.33	118.76	103.24
Purchased power	42.85	42.12	40.11

WE and WPS purchase coal under long-term contracts, which helps with price stability. In the past, coal and associated transportation services were exposed to volatility in pricing due to changing domestic and world-wide demand for coal and diesel fuel. To moderate the volatility, WE and WPS were both given PSCW approval for a hedging program, which allowed them to hedge up to 75% of their potential risks related to rail transportation fuel surcharge exposure. However, due to decreased volatility over the last few years, we suspended the fuel surcharge hedging program in 2017.

We purchase natural gas for our plants on the spot market from natural gas marketers, utilities, and producers, and we arrange for transportation of the natural gas to our plants. We have firm and interruptible transportation, as well as balancing and storage agreements, intended to support our plants' variable usage. WE and WPS also have PSCW-approved programs that allow them to hedge up to 75% of their estimated natural gas use for electric generation in order to help manage their natural gas price risk.

Our hedging programs are generally implemented on a 36-month forward-looking basis. The results of these programs are reflected in the average costs of natural gas and purchased power.

Coal Supply

We diversify the coal supply for our electric generating facilities and jointly-owned plants by purchasing coal from several mines in Wyoming, as well as from various other states. For 2019, approximately 85% of our total projected coal requirements of 8.9 million tons are contracted under fixed-price contracts. See Note 22, Commitments and Contingencies, for more information on amounts of coal purchases and coal deliveries under contract.

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The annual tonnage amounts contracted for the next two years are as follows. We have not entered into any coal contracts for years after 2020.

(in thousands)	Annual Tonnage
2019	7,545
2020	2,317

Coal Deliveries

All of our 2019 coal requirements are expected to be shipped by our owned or leased unit trains under existing transportation agreements. The unit trains transport the coal for electric generating facilities from mines in Wyoming, Pennsylvania, and Montana. The coal is transported by train to our rail-served electric-generating facilities and to dock storage in Superior, Wisconsin, until needed by our lake vessel-served facility, PIPP. See Note 6, Property, Plant, and Equipment, for more information about the planned retirement of PIPP. Additional small volume agreements may also be used to supplement the normal coal supply for our facilities.

Midcontinent Independent System Operator Costs

In connection with its status as a FERC approved RTO, MISO developed and operates the MISO Energy Markets, which include its bid-based energy and ancillary services markets. We are participants in the MISO Energy Markets. For more information on MISO, see D. Regulation.

Power Purchase Commitments

We enter into short and long-term power purchase commitments to meet a portion of our anticipated electric energy supply needs. Our power purchase commitments with unaffiliated parties are 1,387 MW per year for 2019 and 2020, 1,379 MW for 2021, and 1,133 MW per year for 2022 and 2023, which exclude planning capacity purchases. These amounts include 1,033 MW per year related to a long-term power purchase agreement for electricity generated by Point Beach. Due to the actual and planned retirement of generation resources, we have entered into purchase agreements to procure additional planning capacity in order to maintain our compliance with planning reserve requirements as established by the PSCW, MPSC, and MISO.

Other Matters

Seasonality

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

Competition

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

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

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Environmental Matters

For information regarding environmental matters, especially as they relate to coal-fired generating facilities, see Note 22, Commitments and Contingencies.

Natural Gas Utility Operations

We are authorized to provide retail natural gas distribution service in designated territories in the state of Wisconsin, as established by indeterminate permits and boundary agreements with other utilities. We also transport customer-owned natural gas. Together our natural gas distribution utilities are the largest in Wisconsin, and we operate throughout the state, including the City of Milwaukee and surrounding areas, northeastern Wisconsin, and in large areas of both central and western Wisconsin.

Effective January 1, 2017, WPS transferred its natural gas customers and natural gas distribution assets located in the Upper Peninsula of Michigan to UMERC, which is included in our Wisconsin segment. More information about UMERC is included at the beginning of the Wisconsin segment section.

We provide natural gas utility service to a diversified base of industrial customers who are largely within our electric service territory. Major industries served include governmental, food products, paper, education, and metals manufacturing. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Wisconsin Segment Contribution to Operating Income for information on natural gas sales volumes by customer class in Wisconsin and the Upper Peninsula of Michigan.

Operating Revenues

The following table shows natural gas utility operating revenues for our Wisconsin segment. For information about our operating revenues disaggregated by customer class for the year ended December 31, 2018, see Note 4, Operating Revenues. For more information about our significant accounting policies related to the recognition of revenues, see Note 1(d), Operating Revenues.

	Year Ended December 31	
(in millions)	2017	2016
Operating revenues		
Residential	$809.3	$763.2
Commercial and industrial	395.5	355.3
Total retail revenues	1,204.8	1,118.5
Transport	72.6	69.7
Other operating revenues *	(7.2)	(10.6)
Total operating revenues	$1,270.2	$1,177.6

*Includes amounts refunded to customers for purchased gas adjustment costs.

Natural Gas Sales Forecast

Our combined Wisconsin service territories experienced growth in weather-normalized retail natural gas deliveries (excluding natural gas deliveries for electric generation) in 2018 due to customer growth. We currently forecast retail natural gas delivery volumes to grow at a rate between 0.5% and 1.0% over the next five years, assuming normal weather.

Customers

	Year Ended December 31		
(in thousands)	2018	2017	2016
Customers – end of year			
Residential	1,329.6	1,318.3	1,306.3
Commercial and industrial	130.6	129.7	129.0
Transport	3.0	2.8	2.6
Total customers	1,463.2	1,450.8	1,437.9

Natural Gas Supply, Pipeline Capacity and Storage

We have been able to meet our contractual obligations with both our suppliers and our customers. For more information on our natural gas utility supply and transportation contracts, see Note 22, Commitments and Contingencies.

Pipeline and Storage Capacity

The interstate pipelines serving Wisconsin originate in major natural gas producing areas of North America: the Oklahoma and Texas basins, western Canada, and the Rocky Mountains. We have contracted for long-term firm capacity from a number of these sources. This strategy reflects management's belief that overall supply security is enhanced by geographic diversification of the supply portfolio.

Due to variations in natural gas usage in Wisconsin, we have also contracted for substantial underground storage capacity, primarily in Michigan. We target storage inventory levels at approximately 40% of forecasted demand for November through March. Diversity of natural gas supply enables us to manage significant changes in demand and to optimize our overall natural gas supply and capacity costs. We generally inject natural gas into storage during the spring and summer months and withdraw it in the winter months.

In June 2017, we completed the acquisition of Bluewater. Bluewater owns natural gas storage facilities in Michigan that provide approximately one-third of the current storage needs for our Wisconsin natural gas utilities. See Note 2, Acquisitions, for more information on this transaction.

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

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

To ensure a reliable supply of natural gas during peak winter conditions, we have liquefied natural gas and propane facilities located within our distribution system. These facilities are typically utilized during extreme demand conditions to ensure reliable supply to our customers.

Combined with our storage capability, management believes that the volume of natural gas under contract is sufficient to meet our forecasted firm peak-day and seasonal demand. Our Wisconsin natural gas utilities' forecasted design peak-day throughput is 32.5 million therms for the 2018 through 2019 heating season. Our peak daily send-out during 2018 was 24.2 million therms on January 4, 2018.

Natural Gas Supply

We have contracts for firm supplies with terms of 3–5 months with suppliers for natural gas acquired in the Chicago, Illinois market hub and in the producing areas discussed above. The pricing of the term contracts is based upon first of the month indices.

We expect to continue to make natural gas purchases in the spot market as price and other circumstances dictate. We have supply relationships with a number of sellers from whom we purchase natural gas in the spot market.

Hedging Natural Gas Supply Prices

WE, WPS, and WG have PSCW approval to hedge up to 60% of planned winter demand and up to 15% of planned summer demand using a mix of NYMEX-based natural gas options and futures contracts. These approvals allow these companies to pass 100% of the hedging costs (premiums and brokerage fees) and proceeds (gains and losses) to customers through their respective GCRMs.

To the extent that opportunities develop and physical supply operating plans are supportive, WE, WG, and WPS also have PSCW approval to utilize NYMEX-based natural gas derivatives to capture favorable forward-market price differentials. These approvals provide for 100% of the related proceeds to accrue to these companies' respective GCRMs.

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Seasonality

Since the majority of our customers use natural gas for heating, customer use is sensitive to weather and is generally higher during the winter months. Accordingly, we are subject to some variations in earnings and working capital throughout the year as a result of changes in weather.

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

Competition

We face varying degrees of competition from other entities and other forms of energy available to consumers. Many large commercial and industrial customers have the ability to switch between natural gas and alternative fuels. Commercial and industrial customers have the opportunity to choose a natural gas supplier other than us. We offer both natural gas transportation service and interruptible natural gas sales to enable customers to better manage their energy costs. Transportation customers purchase natural gas directly from third-party natural gas suppliers and use our distribution systems to transport the natural gas to their facilities. We earn a distribution charge for transporting the natural gas for these customers. As such, the loss of revenue associated with the cost of natural gas that our transportation customers purchase from third-party suppliers has little impact on our net income, as it is offset by an equal reduction to natural gas costs. Customers continue to switch between firm system supply, interruptible system supply, and transportation service each year as the economics and service options change.

Illinois Segment

Our Illinois segment includes the natural gas utility operations of PGL and NSG. PGL and NSG, both Illinois corporations, began operations in 1855 and 1900, respectively. Our customers are located in Chicago and the northern suburbs of Chicago. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Illinois Segment Contribution to Operating Income for information on natural gas sales volumes by customer class.

Illinois Utilities Operating Statistics

Operating Revenues

The following table shows natural gas operating revenues for our Illinois utilities. For information about our operating revenues disaggregated by customer class for the year ended December 31, 2018, see Note 4, Operating Revenues. For more information about our significant accounting policies related to the recognition of revenues, see Note 1(d), Operating Revenues.

	Year Ended December 31	
(in millions)	2017	2016
Operating revenues		
Residential	$934.8	$839.2
Commercial and industrial	156.7	136.5
Total retail revenues	1,091.5	975.7

Transport	246.9	239.4
Other operating revenues	17.1	27.1
Total operating revenues	$1,355.5	$1,242.2

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Customers

	Year Ended December 31		
(in thousands)	2018	2017	2016
Customers – end of year			
Residential	863.2	849.8	822.6
Commercial and industrial	72.1	72.9	71.3
Transport	97.5	107.5	109.5
Total customers	1,032.8	1,030.2	1,003.4

Natural Gas Supply, Pipeline Capacity, and Storage

We manage portfolios of natural gas supply contracts, storage services, and pipeline transportation services designed to meet varying customer use patterns with safe, reliable natural gas supplies at the best value. For more information on our natural gas utility supply and transportation contracts, see Note 22, Commitments and Contingencies.

Pipeline Capacity and Storage

We contract with local distribution companies and interstate pipelines to purchase firm transportation services. We believe that having multiple pipelines that serve our natural gas service territory benefits our customers by improving reliability, providing access to a diverse supply of natural gas, and fostering competition among these service providers. These benefits can lead to favorable conditions for our Illinois utilities when negotiating new agreements for transportation and storage services.

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

We had adequate capacity to meet all firm natural gas demand obligations during 2018 and expect to have adequate capacity to meet all firm demand obligations during 2019. Our Illinois utilities' forecasted design peak-day throughput is 24.8 million therms for the 2018 through 2019 heating season.

Natural Gas Supply

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

Hedging Natural Gas Supply Prices

Our Illinois utilities further reduce their supply cost volatility through the use of financial instruments, such as commodity futures, swaps, and options as part of their hedging programs. Their hedging programs are approved by the ICC. They hedge between 25% and 50% of natural gas purchases, with a target of 37.5%.

Natural Gas System Modernization Program

PGL is continuing work on the SMP, a project to replace approximately 2,000 miles of Chicago's aging natural gas pipeline infrastructure that began in 2011. PGL currently recovers these costs through a surcharge on customer bills pursuant to an ICC approved QIP rider, which is in effect through 2023. For information on regulatory proceedings related to the SMP, see Note 24, Regulatory Environment.

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Seasonality

Since the majority of our customers use natural gas for heating, customer use is sensitive to weather and is generally higher during the winter months. Accordingly, we are subject to variations in earnings and working capital throughout the year as a result of changes in weather.

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

Competition

Although our Illinois utilities' rates are regulated by the ICC, we still face varying degrees of competition from other entities and other forms of energy available to consumers. Absent extraordinary circumstances, potential competitors are not allowed to construct competing natural gas distribution systems in our service territory due to a judicial doctrine known as the "first in the field." In addition, we believe it would be impractical to construct competing duplicate distribution facilities due to the high cost of installation.

Since 2002, all our Illinois utilities' natural gas customers have had the opportunity to choose a natural gas supplier other than us. As a result, we offer natural gas transportation service to enable customers to directly manage their energy costs. Transportation customers purchase natural gas directly from third-party natural gas suppliers and use our distribution system to transport the natural gas to their facilities. We still earn a distribution charge for transporting the natural gas for these customers. As such, the loss of revenue associated with the cost of natural gas that our transportation customers purchase from third-party suppliers has little impact on our net income, as it is offset by an equal reduction to natural gas costs.

An interstate pipeline may seek to provide transportation service directly to end users, which would bypass our natural gas transportation service. However, we have a bypass rate approved by the ICC, which allows us to negotiate rates with customers that are potential bypass candidates to help ensure that such customers use our transportation service.

Other States Segment

Our other states segment includes the natural gas utility operations of MERC and MGU. MERC serves customers in various cities and communities throughout Minnesota, and MGU serves customers in southern and western Michigan. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Other States Segment Contribution to Operating Income for information on natural gas sales volumes by customer class for this segment.

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Other States Utilities Operating Statistics

Operating Revenues

The following table shows natural gas operating revenues for our other states utilities. For information about our operating revenues disaggregated by customer class for the year ended December 31, 2018, see Note 4, Operating Revenues. For more information about our significant accounting policies related to the recognition of revenues, see Note 1(d), Operating Revenues.

	Year Ended December 31	
(in millions)	2017	2016
Operating revenues		
Residential	$220.2	$209.3
Commercial and industrial	123.9	110.7
Total retail revenues	344.1	320.0
Transport	31.4	31.7
Other operating revenues	35.7	24.8
Total operating revenues	$411.2	$376.5

Customers

	Year Ended December 31		
(in thousands)	2018	2017	2016
Customers – end of year			
Residential	356.5	353.0	348.1
Commercial and industrial	34.9	34.5	34.1
Transport	24.7	24.2	24.8
Total customers	416.1	411.7	407.0

Natural Gas Supply, Pipeline Capacity and Storage

We manage portfolios of natural gas supply contracts, storage services, and pipeline transportation services designed to meet varying customer use patterns with safe, reliable natural gas supplies at the best value. For more information on our natural gas utility supply and transportation contracts, see Note 22, Commitments and Contingencies.

Pipeline Capacity and Storage

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

Combined with our storage capability, management believes that the volume of gas under contract is sufficient to meet our forecasted firm peak-day and seasonal demand. Forecasted design peak-day throughput for our other states utilities is 8.7 million therms for the 2018 through 2019 heating season.

Natural Gas Supply

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

Hedging Natural Gas Supply Prices

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

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demand using NYMEX financial instruments. MGU has MPSC approval to hedge up to 20% of its planned annual purchases using NYMEX financial instruments.

Seasonality

Since the majority of our customers use natural gas for heating, customer use is sensitive to weather and is generally higher during the winter months. Accordingly, we are subject to variations in earnings and working capital throughout the year as a result of changes in weather.

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

Competition

Although our other states utilities' rates are regulated by the MPUC and MPSC, we still face varying degrees of competition from other entities and other forms of energy available to consumers. Natural gas utilities in the state of Minnesota do not have exclusive franchise service territories and, as a matter of law and policy, natural gas utilities may compete for new customers. However, natural gas utilities have customarily avoided competing for existing customers of other utilities, as there would be duplicative utility facilities and/or increased costs to customers. If this approach were to change, it could lead to a greater level of utility to utility competition for customers.

Many large commercial and industrial customers have the ability to switch between natural gas and alternative fuels. In addition, MERC commercial and industrial customers and all MGU customers have the opportunity to choose a natural gas supplier other than us. We offer natural gas transportation service and also offer interruptible natural gas sales to enable customers to better manage their energy costs. Transportation customers purchase natural gas directly from third-party natural gas suppliers and use our distribution systems to transport the natural gas to their facilities. We still earn a distribution charge for transporting the natural gas for these customers. As such, the loss of revenue associated with the cost of natural gas that our transportation customers purchase from third-party suppliers has little impact on our net income, as it is offset by an equal reduction to natural gas costs. Customers continue to switch between firm system supply, interruptible system supply, and transportation service each year as the economics and service options change.

Electric Transmission Segment

ATC is a regional transmission company that owns, maintains, monitors, and operates electric transmission systems in Wisconsin, Michigan, Illinois, and Minnesota. ATC is expected to provide comparable service to all customers, including WE, WPS, and UMERC, and to support effective competition in energy markets without favoring any market participant. ATC is regulated by the FERC for all rate terms and conditions of service and is a transmission-owning member of MISO. MISO maintains operational control of ATC's transmission system, and WE, WPS, and UMERC are non-transmission owning members and customers of MISO. As of December 31, 2018, our ownership interest in ATC was approximately 60%. In addition, we 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.

In April 2011, ATC and Duke Energy announced the creation of a joint venture, DATC, that seeks opportunities to acquire, build, own, and operate new electric transmission infrastructure in North America to address increasing demand for affordable, reliable transmission capacity. In April 2013, DATC acquired a 72% interest in California's Path 15 transmission rights. DATC continues to evaluate new projects and opportunities, along with participating in the competitive bidding process on projects it considers viable. These projects are located in the service territories of several different RTOs around the country. See Note 19, Investment in Transmission Affiliates, for more information.

ATC is currently named as one of several parties to a complaint filed with the FERC requesting a reduction in the base ROE used by MISO transmission owners. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity, and Capital Resources – Other Matters – American Transmission Company Allowed Return on Equity Complaints, for more information.

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C. NON-UTILITY OPERATIONS

Non-Utility Energy Infrastructure Segment

The non-utility energy infrastructure segment includes We Power, which owns and leases generating facilities to WE; Bluewater, which owns underground natural gas storage facilities in Michigan; our 90% membership interest in Bishop Hill III, a wind generating facility; our 80% membership interest in Coyote Ridge, a wind generating facility under construction; and our 80% membership interest in Upstream, a wind generating facility acquired in January 2019. See Note 2, Acquisitions, for more information.

We Power, through wholly owned subsidiaries, designed and built approximately 2,450 MW of generation in Wisconsin. This generation is made up of capacity from the ERGS units, ER 1 and ER 2, which were placed in service in February 2010 and January 2011, respectively, and the PWGS units, PWGS 1 and PWGS 2, which were placed in service in July 2005 and May 2008, respectively. Two unaffiliated entities collectively own approximately 17%, or approximately 211 MW, of ER 1 and ER 2. We Power's share of the ERGS units and both PWGS units are being leased to WE under long-term leases (the ERGS units have 30-year leases and the PWGS units have 25-year leases), and are positioned to provide a significant portion of our future generation needs.

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

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

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

Bishop Hill III is a 132 MW wind generating facility consisting of 53 wind turbines located in Henry County, Illinois. Bishop Hill III has a 22-year offtake agreement with an unaffiliated company for the sale of all energy produced by the facility. We have a 90% membership interest in Bishop Hill III. Under the Tax Legislation, our investment in Bishop Hill III qualifies for production tax credits and 100% bonus depreciation.

Coyote Ridge is a wind generating facility under construction in Brookings County, South Dakota. The wind generating facility is expected to be in service by the end of 2019. The Coyote Ridge site will consist of 39 wind turbines with a combined capacity of 97.5 MW. The project has a 12-year offtake agreement with an unaffiliated third party for all energy produced by the facility. We have an 80% membership interest in Coyote Ridge. Under the Tax Legislation, our investment in Coyote Ridge is expected to qualify for production tax credits and 100% bonus depreciation. We are entitled to 99% of the tax benefits related to this facility.

In January 2019, we purchased an 80% membership interest in Upstream, a commercially operational 202.5 MW wind generating facility consisting of 81 wind turbines located in Antelope County, Nebraska, which supplies energy to the Southwest Power Pool. Upstream's revenue will be substantially fixed over a 10-year period through an agreement with an unaffiliated third party. Under the Tax Legislation, our investment in Upstream qualifies for production tax credits and 100% bonus depreciation.

Corporate and Other Segment

The corporate and other segment includes the operations of the WEC Energy Group holding company, the Integrys holding company, and the PELLC holding company, as well as the operations of Wispark, Bostco (prior to the sale of substantially all of its remaining assets in the first quarter of 2017 and its dissolution in October 2018), Wisvest (prior to the sale of its assets in the second quarter of

2016), WECC, WBS, PDL, and ITF (prior to the sale of this business in the first quarter of 2016). See Note 3, Dispositions, for more information on the sale of Wisvest's and Bostco's assets and ITF.

Wispark develops and invests in real estate, primarily in southeastern Wisconsin. Wispark had $40.7 million in real estate holdings at December 31, 2018.

Bostco was originally formed to develop and invest in real estate. In March 2017, we sold the remaining real estate holdings of Bostco located in downtown Milwaukee, Wisconsin. See Note 3, Dispositions, for more information. In October 2018, Bostco was dissolved.

Wisvest was originally formed to develop, own, and operate electric generating facilities and to invest in other energy-related entities. However, Wisvest discontinued its development activity several years ago. In April 2016, we sold the chilled water generation and distribution assets of Wisvest, which provided chilled water services to the Milwaukee Regional Medical Center. Wisvest no longer has significant operations. See Note 3, Dispositions, for more information.

WECC was originally formed to invest in non-utility projects, such as low income housing developments. However, due to a focus on our regulated utility business, WECC sold many of its non-utility investments and no longer has significant operations.

WBS is a wholly owned centralized service company that provides administrative and general support services to our regulated entities. WBS also provides certain administrative and support services to our nonregulated entities.

PDL owns distributed renewable solar projects. As part of our asset management strategy, in 2016, PDL sold its natural gas-fired cogeneration facility and its landfill gas facility, and in 2018, PDL sold three of its distributed commercial and industrial solar projects. These facilities were not considered core to our operations. PDL's solar facilities rely on solar irradiance, a renewable energy resource. There is no market price risk associated with the fuel supply of these solar projects. However, production at these facilities can be intermittent due to the variability of solar irradiance.

D. REGULATION

We are a holding company and are subject to the requirements of the Public Utility Holding Company Act of 2005 (PUHCA 2005). We also have various subsidiaries that meet the definition of a holding company under PUHCA 2005 and are also subject to its requirements.

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

Regulated Utility Operations

In addition to the specific regulations noted above and below, our utilities are also subject to regulations, where applicable, of the EPA, the WDNR, the MDEQ, the Michigan Department of Natural Resources, the Illinois Environmental Protection Agency, the United States Army Corps of Engineers, the Minnesota Department of Natural

Resources, and the Minnesota Pollution Control Agency.

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Rates

Our utilities' rates were regulated by the various commissions shown in the table below during 2018. These commissions have general supervisory and regulatory powers over public utilities in their respective jurisdictions.

Regulated Rates	Regulatory Commission
WE	
Retail electric, natural gas, and steam	PSCW
Retail electric	MPSC
Wholesale power	FERC
WPS	
Retail electric and natural gas	PSCW
Wholesale power	FERC
WG	
Retail natural gas	PSCW
UMERC	
Retail electric and natural gas	MPSC
Wholesale power	FERC
PGL	
Retail natural gas	ICC
NSG	
Retail natural gas	ICC
MERC	
Retail natural gas	MPUC
MGU	
Retail natural gas	MPSC

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

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

See Note 1(d), Operating Revenues, for additional information on the significant mechanisms our utilities had in place in 2018 that allowed them to recover or refund changes in prudently incurred costs from rate case-approved amounts.

WE, WG, and WPS are each subject to an earnings sharing mechanism through 2019. WE and WG have been subject to the earnings sharing mechanism since January 2016, and WPS adopted it in January 2018 pursuant to its settlement agreement with the PSCW. See Note 24, Regulatory Environment, for more information.

For information on how rates are set for our regulated entities, see Note 24, Regulatory Environment. Orders from our respective regulators can be viewed at the following websites:

Regulatory Commission	Website

PSCW	https://psc.wi.gov/
ICC	https://www.icc.illinois.gov/
MPSC	http://www.michigan.gov/mpsc/
MPUC	http://mn.gov/puc/
FERC	http://www.ferc.gov/

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

The following table compares our utility operating revenues by regulatory jurisdiction for each of the three years ended December 31:

	2018		2017		2016	
(in millions)	Amount	Percent	Amount	Percent	Amount	Percent
Electric						
Wisconsin	$3,890.4	87.7 %	$3,909.1	85.7 %	$3,974.8	85.9 %
Michigan	152.4	3.4 %	145.9	3.2 %	175.0	3.8 %
FERC – Wholesale	396.1	8.9 %	504.0	11.1 %	478.3	10.3 %
Total	4,438.9	100.0%	4,559.0	100.0%	4,628.1	100.0%
Natural Gas						
Wisconsin	1,351.8	42.3 %	1,266.4	41.7 %	1,174.2	42.0 %
Illinois	1,400.0	43.8 %	1,355.5	44.6 %	1,242.2	44.4 %
Minnesota	289.8	9.1 %	272.6	9.0 %	249.4	8.9 %
Michigan	152.4	4.8 %	142.4	4.7 %	130.5	4.7 %
Total	3,194.0	100.0%	3,036.9	100.0%	2,796.3	100.0%
Total utility operating revenues	$7,632.9		$7,595.9		$7,424.4	

Electric Transmission, Capacity, and Energy Markets

In connection with its status as a FERC approved RTO, MISO operates bid-based energy markets. MISO has been able to assume significant balancing area responsibilities such as frequency control and disturbance control.

In MISO, base transmission costs are currently being paid by load-serving entities located in the service territories of each MISO transmission owner. The FERC has previously confirmed the use of the current transmission cost allocation methodology. Certain additional costs for new transmission projects are allocated throughout the MISO footprint.

As part of MISO, a market-based platform is used for valuing transmission congestion premised upon the LMP system that is used in certain northeastern and mid-Atlantic states. The LMP system includes the ability to hedge transmission congestion costs through ARRs and FTRs. ARRs are allocated to market participants by MISO, and FTRs are purchased through auctions. A new allocation and auction were completed for the period of June 1, 2018, through May 31, 2019. The resulting ARR valuation and the secured FTRs are expected to mitigate our transmission congestion risk for that period.

MISO has an annual zonal resource adequacy requirement to ensure there is sufficient generation capacity to serve the MISO market. To meet this requirement, capacity resources can be acquired through MISO's annual capacity auction, bilateral contracts for capacity, or provided from generating or demand response resources. All of our capacity requirements during the planning year from June 1, 2018, through May 31, 2019 were met.

Other Electric Regulations

Our electric utilities are subject to the Federal Power Act and the corresponding regulations developed by certain federal agencies. The Energy Policy Act amended the Federal Power Act in 2005 to, among other things, make electric utility industry consolidation more feasible, authorize the FERC to review proposed mergers and the acquisition of generation facilities, change the FERC regulatory scheme applicable to qualifying cogeneration facilities, and modify certain other aspects of energy regulations and Federal tax policies applicable to us. Additionally, the Energy Policy Act created an Electric Reliability Organization to be overseen by the FERC, which established mandatory electric reliability standards and has the authority to levy monetary sanctions for failure to comply with these standards.

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

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

Other Natural Gas Regulations

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

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

Non-Utility Energy Infrastructure Operations

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

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

Bishop Hill III and Upstream, which was acquired in January 2019, are both subject to the FERC’s regulation of wholesale energy under the Federal Power Act.

E. ENVIRONMENTAL COMPLIANCE

Our operations are subject to extensive environmental regulation by state and federal environmental agencies governing air and water quality, hazardous and solid waste management, environmental remediation, and management of natural resources. Costs associated with complying with these requirements are significant. Additional future environmental regulations or revisions to existing laws, including for example, additional regulation of GHG emissions, coal combustion products, air emissions, or wastewater discharges, could significantly increase these environmental compliance costs.

Anticipated expenditures for environmental compliance and remediation issues for the next three years are included in the estimated capital expenditures described in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Capital Requirements. For a discussion of matters related to manufactured gas plant sites and air and water quality, see Note 22, Commitments and Contingencies.

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F. EMPLOYEES

As of December 31, 2018, we had the following number of employees:

	Total Employees
WE	2,739
WPS	1,189
WG	411
PGL	1,566
NSG	166
MERC	221
MGU	149
WBS	1,437
Total employees	7,878

As of December 31, 2018, we had employees represented under labor agreements with the following bargaining units:

	Number of Employees	Expiration Date of Current Labor Agreement
WE		
Local 2150 of International Brotherhood of Electrical Workers	1,611	August 15, 2020
Local 420 of International Union of Operating Engineers	360	September 30, 2021
Local 2006 Unit 1 of United Steel Workers of America	114	October 31, 2021
Local 510 of International Brotherhood of Electrical Workers	75	October 31, 2020
Total WE	2,160	
WPS		
Local 420 of International Union of Operating Engineers	850	April 16, 2021
WG		
Local 2150 of International Brotherhood of Electrical Workers	81	August 15, 2020
Local 2006 Unit 1 of United Steel Workers of America	209	October 31, 2021
Total WG	290	
PGL		
Local 18007 of Utility Workers Union of America	990	April 30, 2023
Local 18007(C) of Utility Workers Union of America	92	July 31, 2021
Total PGL	1,082	
NSG		
Local 2285 of International Brotherhood of Electrical Workers (1)	121	June 30, 2019
MERC		
Local 31 of International Brotherhood of Electrical Workers	43	May 31, 2020
Local 49 of International Union of Operating Engineers(2)	3	January 1, 2022
Total MERC	46	

MGU		
Local 12295 of United Steelworkers of America	70	January 15, 2020
Local 417 of Utility Workers Union of America	25	February 15, 2022
Total MGU	95	
Total represented employees	4,644	

(1) We anticipate that Local 2285 negotiations will begin in spring 2019 and will conclude before the expiration of the current agreement.

(2) A three year contract was ratified between MERC and the International Union of Operating Engineers, Local 49, on January 10, 2019.

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ITEM 1A. RISK FACTORS

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

Risks Related to Legislation and Regulation

Our business is significantly impacted by governmental regulation and oversight.

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

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

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

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

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

Our operations are subject to numerous federal and state environmental laws and regulations. These laws and regulations govern, among other things, air emissions (including, but not limited to: CO_2, methane, mercury, SO_2, and NOx), water quality, wastewater discharges, and management of hazardous, toxic, and solid wastes and substances. We incur significant costs to comply with these environmental requirements, including costs associated with the installation of pollution control equipment, environmental monitoring, emissions fees, and permits at our facilities. In addition, if we fail to comply with environmental laws and regulations, even if caused by factors beyond our control, that failure may result in the assessment of civil or criminal penalties and fines.

The EPA adopted and implemented (or is in the process of implementing) regulations governing the emission of NOx, SO_2, fine particulate matter, mercury, and other air pollutants under the CAA through the NAAQS, the Mercury and Air Toxics Standards rule, the CPP, the Cross-State Air Pollution Rule, and other air quality regulations. In addition, the EPA finalized regulations under the Clean Water Act that govern cooling water intake structures at our power plants and revised the effluent guidelines for steam electric generating plants. The EPA and the United States Army Corps of Engineers (Army Corps) have also adopted a final rule that would expand traditional federal jurisdiction over navigable waters and related wetlands for permitting and other regulatory matters. However, this rule has been stayed, and the EPA and the Army Corps have proposed revisions to it. We continue to assess the potential cost of complying, and to explore different alternatives in order to comply, with these and other environmental regulations. In addition, as a result of the actions taken by the sitting President and Federal Executive Branch since taking office in January 2017, as well as its announced future plans and other factors, there is uncertainty as to what capital expenditures or additional costs may ultimately be required to comply with existing and future environmental laws and regulations.

Existing environmental laws and regulations may be revised or new laws or regulations may be adopted at the federal or state level that could result in significant additional expenditures for our generation units or distribution systems, including, without limitation, costs to further limit GHG emissions from our operations; operating restrictions on our facilities; and increased compliance costs. In addition, the operation of emission control equipment and compliance with rules regulating our intake and discharge of water could increase our operating costs and reduce the generating capacity of our power plants. Any such regulation may also create substantial additional costs in the form of taxes or emission allowances and could affect the availability and/or cost of fossil fuels.

As a result, certain of our coal-fired electric generating facilities have become uneconomical to maintain and operate, which has resulted in some of these units being retired or converted to an alternative type of fuel. For example, as part of our goal to retire approximately 1,800 MW of coal-fired generation by 2020, we retired the Pleasant Prairie power plant, Pulliam power plant, and the jointly-owned Edgewater Unit 4 generating unit during 2018, representing approximately 1,500 MW, and are required to retire PIPP by May 31, 2019. Certain of our remaining coal-fired electric generating facilities may also be retired or converted in the future. If other generation facility owners in the Midwest retire a significant number of older coal-fired generation facilities, a potential reduction in the region's capacity reserve margin below acceptable risk levels may result. This could impair the reliability of the grid in the Midwest, particularly during peak demand periods. A reduction in available future capacity could also adversely affect our ability to serve our customers' needs.

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

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

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

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We may face significant costs to comply with the regulation of greenhouse gas emissions.

Management believes it is reasonably likely that the scientific and political attention to issues concerning the existence and extent of climate change, and the role of human activity in it, will continue, with the potential for further regulation that affects our operations. In 2015, the EPA issued a final rule regulating GHG emissions from existing generating units, referred to as the CPP, and final performance standards for modified and reconstructed generating units and new fossil-fueled power plants. In February 2016, the Supreme Court stayed the effectiveness of the CPP until disposition of certain litigation in the D.C. Circuit Court of Appeals challenging the rule and, to the extent that further appellate review is sought, at the Supreme Court.

In April 2017, pursuant to motions made by the EPA, the D.C. Circuit Court of Appeals ordered the challenges to the CPP, as well as related performance standards for new, reconstructed, and modified fossil-fueled power plants, be held in abeyance, which remains the case. In August 2018, the EPA issued a proposed replacement rule for the CPP, the ACE rule. The proposed ACE rule would require the EPA to develop emission guidelines for states to use to develop their individual state plans. The state plans would focus on reducing GHG emissions by improving the efficiency of fossil-fueled power plants. In December 2018, the EPA proposed to revise the regulations related to new, modified, and reconstructed fossil-fueled power plants. We are continuing to analyze the GHG emission profile of our electric generation resources and to work with other stakeholders to determine the potential impacts to our operations of the CPP, the proposed ACE rule, and federal GHG regulations in general.

There is no guarantee that we will be allowed to fully recover costs incurred to comply with these and other federal regulations or that cost recovery will not be delayed or otherwise conditioned. GHG regulations that may be adopted in the future, at either the federal or state level, may cause our environmental compliance spending to differ materially from the amounts currently estimated. In December 2016, Michigan enacted Act 342, which retains the 10% renewable energy portfolio requirement through 2018, increases the requirement to 12.5% for years 2019 through 2020, and increases the requirement to 15.0% for 2021. These regulations, as well as changes in the fuel markets and advances in technology, could make additional electric generating units uneconomic to maintain or operate, may impact how we operate our existing fossil-fueled power plants and biomass facility, and could affect unit retirement and replacement decisions in the future. These regulations could also adversely affect our future results of operations, cash flows, and financial condition.

In addition, our natural gas delivery systems and natural gas storage fields may generate fugitive gas as a result of normal operations and as a result of excavation, construction, and repair. Fugitive gas typically vents to the atmosphere and consists primarily of methane. CO_2 is also a byproduct of natural gas consumption. As a result, future regulation of GHG emissions could increase the price of natural gas, restrict the use of natural gas, and adversely affect our ability to operate our natural gas facilities. A significant increase in the price of natural gas may increase rates for our natural gas customers, which could reduce natural gas demand.

We also continue to monitor efforts by investors and other stakeholders to increase pressure on us and others to take more aggressive action to reduce future GHG emissions in order to limit future global temperature increases to less than two degrees Celsius. These efforts could impact how we operate our electric generating units and natural gas facilities and lead to increased competition and regulation, all of which could have a material adverse effect on our operations and financial condition.

Changes in federal income tax policy may adversely affect our financial condition, results of operations, and cash flows, as well as our or our subsidiaries' credit ratings.

We and our subsidiaries have invested or will be investing in renewable energy generating facilities, several of which generate production tax credits and investment tax credits that we use to reduce our federal tax obligations. The amount of tax credits we earn depends on the level of electricity generated, the applicable tax credit rate, and the amount of the investment in qualifying property. If our tax credits were disallowed in whole or in part as a results of an IRS audit or changes in tax law, we could owe tax liabilities for previously recognized tax credits that could significantly impact our earnings and cash flows.

In addition, if corporate tax rate or policies are changed with future federal or state legislation, we may be required to take material charges against earnings. For example, the United States federal income tax legislation enacted in December 2017 significantly changed the United States Internal Revenue Code, including taxation of United States corporations, by, among other things, reducing the federal corporate income tax rate, limiting interest deductions, and altering the expensing of capital expenditures. Parts of the Tax Legislation still remain unclear and will require interpretations and implementing regulations by the Treasury Department and the IRS, as well as state income tax authorities, and the Tax Legislation could be subject to potential amendments and technical corrections, any of which could lessen or increase certain adverse impacts of the Tax Legislation. In addition, the regulatory treatment of the impacts of the Tax Legislation will be subject to the discretion of the FERC and state public utility commissions. State and local taxing authorities continue to evaluate the impact of federal income tax reform, and any changes on the state or local level could lessen or increase the impacts of the Tax Legislation.

There is still uncertainty as to when or how credit rating agencies, capital markets, the FERC, or state public utility commissions will treat any additional impacts of the Tax Legislation. These impacts could subject us or any of our subsidiaries to further credit rating downgrades. It is unclear whether additional opportunities may evolve for us to manage the adverse impacts of the Tax Legislation. In addition, certain financial metrics used by credit rating agencies, such as our funds from operations-to-debt percentage, could be negatively impacted by future rulings related to the Tax Legislation.

In addition, the FERC and state public utility commissions continue to engage with our utility subsidiaries to determine how certain tax savings will be returned to ratepayers. In December 2017, our regulated utilities deferred the estimated tax benefits for return to ratepayers through bill credits or reductions in regulatory assets. We have received written orders from the MPSC, the MPUC, and the PSCW addressing the refunding of certain of these tax benefits to ratepayers in Michigan, Minnesota, and Wisconsin, respectively, and the ICC has approved the VITA in Illinois. Despite receiving these written orders, the amount of tax benefits we must return to ratepayers could change if state commissions take additional action. Furthermore, if the amounts our regulators order our regulated utility subsidiaries to return to ratepayers exceeds the actual amount of tax savings realized, or our regulators require the tax savings to be applied in a manner other than we had expected, it could have a material adverse effect on our financial condition, results of operations, and cash flow.

While our analysis and interpretation of the Tax Legislation is ongoing, based on our current evaluation, we do not expect the limitations on interest deductions to materially adversely affect our earnings per share. Any amendments to the Tax Legislation or interpretations or implementing regulations by the Treasury Department and/or the IRS contrary to our interpretation of the Tax Legislation could limit our ability to deduct the interest on some of our outstanding debt.

There may be other material adverse effects resulting from the Tax Legislation that we have not yet identified. If we are unable to successfully take actions to manage any adverse impacts of the Tax Legislation, or if additional interpretations, regulations, amendments, or technical corrections exacerbate the adverse impacts of the Tax Legislation, the Tax Legislation could have an adverse effect on our financial condition, results of operations, cash flows, and on the value of investments in our debt securities and common stock, and could result in credit rating agencies placing our or our subsidiaries’ credit ratings on negative outlook or further downgrading our or our subsidiaries' credit ratings.

Failure to maintain effective internal controls in accordance with Section 404 of the Sarbanes-Oxley Act could have a material effect on our results of operations and stock price.

We are subject to reporting, disclosure control, and other obligations under Section 404 of the Sarbanes-Oxley Act (SOX). SOX contains provisions requiring our management to report on the effectiveness of our internal control over financial reporting and requires our independent registered public accounting firm to attest to the effectiveness of our internal controls. We have undertaken, or will undertake, a variety of initiatives to integrate, standardize, centralize, and streamline our operations with technology, including, but not limited to, an enterprise resource planning system and a customer information and billing system. There is a risk that we will not be able to conclude that our internal control over financial reporting is effective because of the discovery of material weaknesses, with either our current controls and processes or with the implementation of new controls and processes around these new technologies. Any failure to maintain effective internal controls or a determination by our independent registered public accounting firm that we have a material weakness in our internal controls could cause investors to lose confidence in the accuracy or completeness of our financial reports, cause a decline in the market price of our common stock, restrict our access to the capital markets, or subject us to investigations by the SEC or other regulatory authorities.

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

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

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

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

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

Risks Related to the Operation of Our Business

Our operations are subject to risks arising from the reliability of our electric generation, transmission, and distribution facilities, natural gas infrastructure facilities, and other facilities, as well as the reliability of third-party transmission providers.

Our financial performance depends on the successful operation of our electric generation and natural gas and electric distribution facilities. The operation of these facilities involves many risks, including operator error and the breakdown or failure of equipment or processes. Potential breakdown or failure may occur due to severe weather; catastrophic events (i.e., fires, earthquakes, explosions, tornadoes, floods, droughts, pandemic health events, etc.); significant changes in water levels in waterways; fuel supply or transportation disruptions; accidents; employee labor disputes; construction delays or cost overruns; shortages of or delays in obtaining equipment, material, and/or labor; performance below expected levels; operating limitations that may be imposed by environmental or other regulatory requirements; terrorist attacks; or cyber security intrusions. Any of these events could lead to substantial financial losses.

Because our electric generation facilities are interconnected with third-party transmission facilities, the operation of our facilities could also be adversely affected by events impacting their systems. Unplanned outages at our power plants may reduce our revenues, cause us to incur significant costs if we are required to operate our higher cost electric generators or purchase replacement power to satisfy our obligations, and could result in additional maintenance expenses.

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

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

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

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Fluctuations in customer growth and general economic conditions in our service areas. Customer growth and energy use can be negatively impacted by population declines as well as economic factors in our service territories, including workforce reductions, stagnant wage growth, changing levels of support from state and local government for economic development, business closings, and reductions in the level of business investment. Our electric and natural gas utilities are impacted by economic cycles and the competitiveness of the commercial and industrial customers we serve. Any economic downturn, disruption of financial markets, or reduced incentives by state government for economic development could adversely affect the financial condition of our customers and demand for their products or services. These risks could directly influence the demand for electricity and natural gas as well as the need for additional power generation and generating facilities. We could also be exposed to greater risks of accounts receivable write-offs if customers are unable to pay their bills.

- Weather conditions. Demand for electricity is greater in the summer and winter months when cooling and heating is necessary. In addition, demand for natural gas peaks in the winter heating season. As a result, our overall results may fluctuate substantially on a seasonal basis. In addition, milder temperatures during the summer cooling season and during the winter heating season may result in lower revenues and net income.
- Our customers' continued focus on energy conservation and ability to meet their own energy needs. Our customers' use of electricity and natural gas has decreased as a result of continued individual conservation efforts, including the use of more energy

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efficient technologies. Customers could also voluntarily reduce their consumption of energy in response to decreases in their disposable income and increases in energy prices. Conservation of energy can be influenced by certain federal and state programs that are intended to influence how consumers use energy. For example, several states, including Wisconsin and Michigan, have adopted energy efficiency targets to reduce energy consumption by certain dates.

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

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

Our business requires substantial capital expenditures for investments in, among other things, capital improvements to our electric generating facilities, electric and natural gas distribution infrastructure, natural gas storage, and other projects, including projects for environmental compliance. We also expect to invest in renewable energy generating facilities as part of our generation reshaping plan and as part of our non-utility energy infrastructure segment. In addition, WBS continues to invest in technology and the development of software applications to support our utilities.

Achieving the intended benefits of any large construction project is subject to many uncertainties, some of which we will have limited or no control over, that could adversely affect project costs and completion time. These risks include, but are not limited to, the ability to adhere to established budgets and time frames; the availability of labor or materials at estimated costs; the ability of contractors to perform under their contracts; strikes; adverse weather conditions; potential legal challenges; changes in applicable laws or regulations; other governmental actions; continued public and policymaker support for such projects; and events in the global economy. In addition, certain of these projects require the approval of our regulators. If construction of commission-approved projects should materially and adversely deviate from the schedules, estimates, and projections on which the approval was based, our regulators may deem the additional capital costs as imprudent and disallow recovery of them through rates, and otherwise available production tax credits and investment tax credits for renewable energy projects could be lost.

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

Advances in technology could make our electric generating facilities less competitive.

Advances in new technologies that produce power or reduce power consumption are ongoing and include renewable energy technologies, customer-oriented generation, energy storage devices, and energy efficiency technologies. We generate power at central station power plants to achieve economies of scale and produce power at a competitive cost. There are distributed generation technologies that produce power, including fuel cells, microturbines, wind turbines, and solar cells, which have become more cost competitive than they were in the past. It is possible that legislation or regulations could be adopted supporting the use of these technologies. There is also a risk that advances in technology will continue to reduce the costs of these alternative methods of producing power to a level that is competitive with that of central station power production. If these technologies become cost competitive and achieve economies of scale, our market share could be eroded, and the value of our generating facilities could be reduced. Advances in technology could also change the channels through which our electric customers purchase or use power, which could reduce our sales and revenues or increase our expenses.

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

We have been subject to attempted cyber attacks from time to time, but these attacks have not had a material impact on our system or business operations. Despite the implementation of security measures, all assets and systems are potentially vulnerable to disability, failures, or unauthorized access due to physical or cyber security intrusions caused by human error, vendor bugs, terrorist attacks, or other malicious acts. These threats against our generation facilities, electric and natural gas distribution infrastructure, our information and technology systems, and network infrastructure, including that of third parties on which we rely, could result in a full or partial disruption of our ability to generate, transmit, purchase, or distribute electricity or natural gas or cause environmental repercussions. If our assets or systems were to fail, be physically damaged, or be breached, and were not recovered in a timely manner, we may be unable to perform critical business functions, and data, including sensitive information, could be compromised.

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

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

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

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

Transporting, distributing, and storing natural gas involves numerous risks that may result in accidents and other operating risks and costs.

Inherent in natural gas distribution activities are a variety of hazards and operational risks, such as leaks, accidental explosions, and mechanical problems, which could materially and adversely affect our results of operations, financial condition, and cash flows. In addition, these risks could result in serious injury to employees and non-employees, loss of human life, significant damage to property, environmental pollution, impairment of operations, and substantial losses to us. The location of natural gas pipelines and storage facilities near populated areas, including residential areas, commercial business centers, and industrial sites, could increase the level of damages resulting from these risks.

These activities may subject us to litigation and/or administrative proceedings from time to time, which could result in substantial monetary judgments, fines, or penalties against us, or be resolved on unfavorable terms.

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

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

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

We operate in an industry that requires many of our employees to possess unique technical skill sets. Events such as an aging workforce without appropriate replacements, the mismatch of skill sets to future needs, or the unavailability of contract resources may lead to operating challenges or increased costs. These operating challenges include lack of resources, loss of knowledge, and a lengthy time period associated with skill development. In addition, current and prospective employees may determine that they do not wish to work for us. Failure to hire and obtain replacement employees, including the ability to transfer significant internal historical knowledge and expertise to the new employees, may adversely affect our ability to manage and operate our business. If we are unable to successfully attract and retain an appropriately qualified workforce, our results of operations could be adversely affected.

Failure of our counterparties to meet their obligations, including obligations under power purchase, natural gas supply, and transportation agreements, could have an adverse impact on our results of operations.

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

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

We may not be able to fully use tax credits, net operating losses, and/or charitable contribution carryforwards.

We have significantly reduced our consolidated federal and state income tax liability in the past through tax credits, net operating losses, and charitable contribution deductions available under the applicable tax codes. We have not fully used the allowed tax credits, net operating losses, and charitable contribution deductions in our previous tax filings. We may not be able to fully use the tax credits, net operating losses, and charitable contribution deductions available as carryforwards if our future federal and state taxable income and related income tax liability is insufficient to permit their use. In addition, any future disallowance of some or all of those tax credits, net operating losses, or charitable contribution carryforwards as a result of legislation or an adverse determination by one of the applicable taxing jurisdictions could materially affect our tax obligations and financial results.

We have recorded goodwill that could become impaired and adversely affect financial results.

We assess goodwill for impairment on an annual basis or whenever events or circumstances occur that indicate a potential for impairment. If goodwill is deemed to be impaired, we may be required to incur non-cash charges that could materially adversely affect our results of operations. At December 31, 2018, our goodwill was $3,052.8 million.

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Risks Related to Economic and Market Volatility

Our business is dependent on our ability to successfully access capital markets.

We rely on access to credit and capital markets to support our capital requirements, including expenditures for our utility infrastructure and to comply with future regulatory requirements, to the extent not satisfied by the cash flow generated by our operations. We have historically secured funds from a variety of sources, including the issuance of short-term and long-term debt securities. Successful implementation of our long-term business strategies, including capital investment, is dependent upon our ability to access the capital markets, including the banking and commercial paper markets, on competitive terms and rates. In addition, we rely on committed bank credit agreements as back-up liquidity, which allows us to access the low cost commercial paper markets.

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

- A rating downgrade;
- An economic downturn or uncertainty;
- Prevailing market conditions and rules;
- Concerns over foreign economic conditions;
- Changes in tax policy;
- Changes in investment criteria of institutional investors;
- War or the threat of war; and
- The overall health and view of the utility and financial institution industries.

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

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

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

Any downgrade by the rating agencies could:

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

See the risk factor titled "Changes in federal income tax policy may adversely affect our financial condition, results of operations, and cash flows, as well as our or our subsidiaries' credit ratings" above for information about how the Tax Legislation could impact our or our subsidiaries' credits ratings.

Fluctuating commodity prices could negatively impact our electric and natural gas utility operations.

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

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

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

Changes in commodity prices could result in:

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

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

We own and operate several coal-fired electric generating units. Although we generally carry sufficient coal inventory at our generating facilities to protect against an interruption or decline in supply, there can be no assurance that the inventory levels will be adequate. While we have coal supply and transportation contracts in place, we cannot assure that the counterparties to these agreements will be able to fulfill their obligations to supply coal to us or that we will be able to take delivery of all the coal volume contracted for. If we are unable to obtain our coal requirements under our coal supply and transportation contracts, we may be required to purchase coal at higher prices or we may be forced to reduce generation at our coal-fired units, which could lead to increased fuel costs. The increase in fuel costs could result in either reduced margins on net sales into the MISO Energy Markets, a reduction in the volume of net sales into the MISO Energy Markets, and/or an increase in net power purchases in the MISO Energy Markets. There is no guarantee that we would be able to fully recover any increased costs in rates or that recovery would not otherwise be delayed, either of which could adversely affect our cash flows.

The use of derivative contracts could result in financial losses.

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

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

The regulated energy industry continues to experience significant structural changes. Increased competition in the retail and wholesale markets, which may result from restructuring efforts, could have a significant adverse financial impact on us.

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

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

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

We may experience poor investment performance of benefit plan holdings due to changes in assumptions and market conditions.

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

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

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

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

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ITEM 2. PROPERTIES

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

A. REGULATED

Electric Facilities

The following table summarizes information on our electric generation facilities, including owned and jointly owned facilities, as of December 31, 2018:

Name	Location	Fuel	Number of Generating Units	Rated Capacity In MW (1)	
Coal-fired plants					
Columbia	Portage, WI	Coal	2	315	(2)
ERGS	Oak Creek, WI	Coal	2	1,057	(3) (4)
PIPP	Marquette, MI	Coal	5	353	(5)
OCPP	Oak Creek, WI	Coal	4	1,079	
Weston	Rothschild, WI	Coal	2	714	(2)
Total coal-fired plants			15	3,518	
Natural gas-fired plants					
Concord Combustion Turbines	Watertown, WI	Natural Gas/Oil	4	359	
De Pere Energy Center	De Pere, WI	Natural Gas/Oil	1	165	
Fox Energy Center	Wrightstown, WI	Natural Gas	3	567	
Germantown Combustion Turbines	Germantown, WI	Natural Gas/Oil	5	270	
Paris Combustion Turbines	Union Grove, WI	Natural Gas/Oil	4	360	
PWGS	Port Washington, WI	Natural Gas	2	1,232	(4)
Pulliam	Green Bay, WI	Natural Gas/Oil	1	80	
VAPP	Milwaukee, WI	Natural Gas	2	269	
West Marinette	Marinette, WI	Natural Gas/Oil	3	150	
Weston	Rothschild, WI	Natural Gas/Oil	3	138	
Total natural gas-fired plants			28	3,590	
Renewables					
Hydro Plants (30 in number)	WI and MI	Hydro	81	102	(6)
Rothschild Biomass Plant	Rothschild, WI	Biomass	1	46	
Blue Sky Green Field	Fond du Lac, WI	Wind	88	17	
Byron Wind Turbines	Fond du Lac, WI	Wind	2	—	
Crane Creek	Howard County, IA	Wind	66	17	
Glacier Hills	Cambria, WI	Wind	90	26	
Forward Wind Energy Center	Fond du Lac County, WI	Wind	86	9	(7)
Montfort Wind Energy Center	Montfort, WI	Wind	20	3	
Total renewables			434	220	
Total system			477	7,328	

(1)

Values are primarily based on the net dependable capacity ratings for summer 2019 using historical generation. The summer period is the most relevant for capacity planning purposes. This is a result of continually reaching demand peaks in the summer months, primarily due to air conditioning demand.

(2) These facilities are jointly owned by WPS and various other utilities. The capacity indicated for each of these units is equal to WPS's portion of total plant capacity based on its percent of ownership.

- Wisconsin Power and Light Company, an unaffiliated utility, operates the Columbia units. WPS holds a 28.1% ownership interest in Columbia. See Note 7, Jointly Owned Utility Facilities, for more information on the decrease in WPS's ownership interest in the Columbia unit.

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- WPS operates the Weston 4 facility and holds a 70.0% ownership interest in this facility. Dairyland Power Cooperative holds the remaining 30.0% interest.

(3) This facility is jointly owned by We Power and two other unaffiliated entities. The capacity indicated for the facility is equal to We Power's portion of total plant capacity based on its 83.34% ownership.

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

(5) We are required to retire the PIPP units during the second quarter of 2019. See Note 6, Property, Plant, and Equipment, for more information on the plant retirement.

(6) WRPC owns and operates the Castle Rock and Petenwell units. WPS holds a 50.0% ownership interest in WRPC and is entitled to 50.0% of the total capacity at Castle Rock and Petenwell. WPS's share of capacity for Castle Rock is 8.4 MW, and WPS's share of capacity for Petenwell is 10.2 MW.

(7) In April 2018, WPS, along with two other unaffiliated utilities, purchased Forward Wind Energy Center, which consists of 86 wind turbines located in Wisconsin with a total capacity of 138 MW. The capacity indicated for the facility is equal to WPS's portion of total plant capacity based on its 44.6% ownership. See Note 2, Acquisitions, for more information on the acquisition.

As of December 31, 2018, we operated approximately 36,800 miles of overhead distribution lines and 33,300 miles of underground distribution cable, as well as approximately 500 electric distribution substations and 500,450 line transformers.

Natural Gas Facilities

At December 31, 2018, our natural gas properties were located in Illinois, Wisconsin, Minnesota, and Michigan, and consisted of the following:

- Approximately 48,900 miles of natural gas distribution mains,
- Approximately 1,100 miles of natural gas transmission mains,
- Approximately 2.3 million natural gas lateral services,
- Approximately 520 natural gas distribution and transmission gate stations,
- Approximately 68.2 billion cubic feet of working gas capacities in underground natural gas storage fields:
  Bluewater, 26.5 billion cubic feet of fields located in southeastern Michigan,
  Manlove, a 38.8 billion-cubic-foot field located in central Illinois,
  Partello, a 2.9 billion-cubic-foot field located in southern Michigan,
- A 2.0 billion-cubic-foot liquefied natural gas plant located in central Illinois,
- A peak-shaving facility that can store the equivalent of approximately 80 MDth in liquefied petroleum gas located in Illinois,
- Peak propane air systems providing approximately 2,960 Dth per day, and
- Liquefied natural gas storage plants with a total send-out capability of 73,600 Dth per day.

Our natural gas distribution and gas storage systems included distribution mains and transmission mains connected to the pipeline transmission systems of ANR Pipeline Company, Centra Pipelines, Consumers Energy, Great Lakes Transmission Company, Guardian Pipeline L.L.C., Michigan Consolidated Gas Company, Natural Gas Pipeline Company of America, Northern Natural Pipeline Company, Union Gas, Vector Pipeline Company, and Viking Gas Transmission. Our liquefied natural gas storage plants convert and store, in liquefied form, natural gas received during periods of low consumption.

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

Steam Facilities

As of December 31, 2018, the steam system supplied by the VAPP consisted of approximately 40 miles of both high pressure and low pressure steam piping, approximately four miles of walkable tunnels, and other pressure regulating equipment.

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General

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

B. NON-UTILITY ENERGY INFRASTRUCTURE SEGMENT

Bluewater and We Power are considered non-utility energy infrastructure operations, however, their facilities are shown in the regulated section. We Power owns and leases generating facilities to WE. We Power's share of the ERGS units and both PWGS units are being leased to WE under long-term leases. Bluewater provides natural gas storage and hub services to WE, WG, and WPS.
In January 2019, we completed the acquisition of an 80% ownership interest in Upstream, a wind generation facility located in Antelope County, Nebraska. The Upstream site consists of 81 wind turbines with a combined capacity of 202.5 MW. See Note 2, Acquisitions, for more information.
In December 2018, we completed the acquisition of an 80% ownership interest in Coyote Ridge, a wind generation facility under construction in Brookings County, South Dakota. Coyote Ridge is expected to be in service by the end of 2019. The Coyote Ridge site will consist of 39 wind turbines with a combined capacity of 97.5 MW. See Note 2, Acquisitions, for more information.
In August 2018, we completed the acquisition of an 80% ownership interest in Bishop Hill III, which consists of 53 wind turbines located in Henry County, Illinois with a total capacity of 132 MW. In December 2018, we acquired an additional 10% membership interest in this wind farm. See Note 2, Acquisitions, for more information.

C. CORPORATE AND OTHER

As of December 31, 2018, the corporate and other segment facilities consisted of energy asset facilities owned by PDL.

The energy asset facilities owned by PDL include a portfolio of residential solar facilities and a portfolio of commercial and industrial solar facilities. The solar facilities consist of distributed solar projects ranging from small residential roof top systems up to commercial and industrial solar systems of 4.5 MW in size. The total capacity of these solar projects is 22.2 MW, a decrease from December 31, 2017 resulting from the sale of three PDL distributed commercial and industrial solar projects in 2018, including one that was jointly owned by PDL and Duke Energy Generation Services. These facilities were not significant to our operations.

ITEM 3. LEGAL PROCEEDINGS

The following should be read in conjunction with Note 22, Commitments and Contingencies, and Note 24, 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 22, Commitments and Contingencies, Note 24, Regulatory Environment, and below, we are currently, and from time to time, subject to claims and suits arising in the ordinary course of business. Although the results of these additional legal proceedings cannot be predicted with certainty, management believes, after consultation with legal counsel, that the ultimate resolution of these proceedings will not have a material effect on our financial statements.

Environmental Matters

Manlove Field Matter

In September 2017, the Illinois Department of Natural Resources, Office of Oil and Gas Resource Management, issued an NOV to PGL related to a leak of natural gas that PGL identified at its Manlove Gas Storage Field in December 2016. PGL quickly contained the leak after it was discovered. The leak resulted in the migration of natural gas from a well located at the facility to the Mahomet Aquifer located in central Illinois, which impacted residential freshwater wells. PGL has been working with residents potentially impacted by the natural gas leak, and the Illinois state agencies to investigate and remediate the impacts of the natural gas leak to the Mahomet Aquifer. In October 2017, the Illinois Attorney General (AG) filed a complaint against PGL alleging certain violations of the Illinois Environmental Protection Act and the Oil and Gas Act. PGL entered into an interim agreed order with the State of Illinois in October 2017 whereby PGL agreed, among other things, to continue actions it was already undertaking proactively. In addition, in December 2017, the Illinois Environmental Protection Agency served an NOV to PGL alleging the same violations as the AG, and in January

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2018, served an NOV alleging certain violations of Illinois air emission rules arising from the construction and operation of flaring equipment at the leak site. Both matters have been referred to the AG for enforcement.

In the complaint, as is customary in these types of actions, the AG cited to the statutory penalties allowed by law. Ultimately, the pursuit of any civil penalties is at the AG’s discretion. In the event the AG wishes to consider such penalties, we believe that PGL's high level of cooperation and quick action to remedy the situation and to work with the potentially impacted homeowners would be taken into account. At this time, we believe that civil penalties, if any, will not have a material impact on our financial statements.

Presque Isle Power Plant Matter

In March 2018, the EPA issued a Finding of Violation to WE regarding alleged violations of mercury emission limits for PIPP Units 5, 6, 8, and 9, as well as failure to conduct mercury tests on its low-emitting electric generating units once every 12 months. WE is cooperating with the EPA, and we do not expect this matter to have a material impact on our financial statements.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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EXECUTIVE OFFICERS OF THE REGISTRANT

The names, ages, and positions of our executive officers at December 31, 2018 are listed below along with their business experience during the past five years. All officers are appointed until they resign, die, or are removed pursuant to our Bylaws. There are no family relationships among these officers, nor is there any agreement or understanding between any officer and any other person pursuant to which the officer was selected.

Gale E. Klappa.[(1)] Age 68.
- WEC Energy Group — Chairman of the Board and Chief Executive Officer since October 2017, and from May 2004 to May 2016. Non-Executive Chairman of the Board from May 2016 to October 2017. Director since December 2003. President from April 2003 to August 2013.
- WE — Chairman of the Board since January 2018, and from May 2004 to May 2016. Chief Executive Officer since January 2018, and from August 2003 to May 2016. Director since January 2018, and from December 2003 to May 2016. President from August 2003 to June 2015.

J. Kevin Fletcher.[(2)] Age 60.
- WEC Energy Group — President since October 2018.
- WE — President from May 2016 to November 2018. Director since June 2015. Executive Vice President - Customer Service and Operations from June 2015 to April 2016. Senior Vice President - Customer Operations from October 2011 to June 2015.

Robert M. Garvin. Age 52.
- WEC Energy Group — Executive Vice President - External Affairs since June 2015. Senior Vice President - External Affairs from April 2011 to June 2015.
- WE — Executive Vice President - External Affairs since June 2015. Senior Vice President - External Affairs from April 2011 to June 2015.

William J. Guc. Age 49.
- WEC Energy Group — Controller since October 2015. Vice President since June 2015.
- WE — Vice President and Controller since October 2015.
- Integrys Energy Group — Vice President and Treasurer from December 2010 to June 2015.

Margaret C. Kelsey. Age 54.
- WEC Energy Group — Executive Vice President, Corporate Secretary and General Counsel since January 2018. Executive Vice President from September 2017 to January 2018.
- WE — Executive Vice President, Corporate Secretary and General Counsel since January 2018. Director since January 2018.
- Modine Manufacturing Company - General Counsel, Corporate Secretary, and Vice President - Legal from April 2008 to August 2017. Vice President - Corporate Communications from April 2014 to August 2017.

Frederick D. Kuester. Age 68.
- WEC Energy Group — Senior Executive Vice President since March 2018. Executive Vice President from May 2004 to January 2013.
- WE — Executive Vice President from May 2004 to January 2013.

Scott J. Lauber.[(3)] Age 53.
- WEC Energy Group — Executive Vice President, Chief Financial Officer and Treasurer since October 2018. Executive Vice President and Chief Financial Officer from April 2016 to October 2018. Vice President and Treasurer from

February 2013 to March 2016.

- WE — Executive Vice President, Chief Financial Officer and Treasurer since October 2018. Director since April 2016. Executive Vice President and Chief Financial Officer from April 2016 to October 2018. Vice President and Treasurer from February 2013 to March 2016.

Charles R. Matthews. Age 62.

- PELLC — President since June 2015.
- PGL — Director, President, and Chief Executive Officer since June 2015.
- NSG — Director, President, and Chief Executive Officer since June 2015.
- WE — Senior Vice President - Wholesale Energy and Fuels from January 2012 to June 2015.

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Tom Metcalfe. Age 51.

- WE — President since November 2018. Director since January 2018. Executive Vice President - Generation from April 2016 to November 2018. Senior Vice President - Power Generation from January 2014 to March 2016.

Mary Beth Straka. Age 54.

- WEC Energy Group — Senior Vice President - Corporate Communications and Investor Relations since June 2015.
- WE — Senior Vice President - Corporate Communications and Investor Relations from June 1 to June 28, 2015.
- Barclays — Vice President of Equity Research Power and Utilities Group from September 2008 to May 2015.

Certain executive officers also hold officer and/or director positions at our other significant subsidiaries.

(1) Effective February 1, 2019, Mr. Klappa was appointed Executive Chairman of WEC Energy Group. Also, effective February 1, 2019, Mr. Fletcher succeeded Mr. Klappa as Chairman and Chief Executive Officer of WE. Mr Klappa remains a Director of WE.

(2) Effective February 1, 2019, Mr. Fletcher was appointed President and Chief Executive Officer and a Director of WEC Energy Group. Also effective February 1, 2019, Mr. Fletcher was appointed Chief Executive Officer and Chairman of WE.

(3) Effective February 1, 2019, Mr. Lauber was named Senior Executive Vice President, Chief Financial Officer and Treasurer of WEC Energy Group.

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PART II

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

Number of Common Shareholders

As of January 31, 2019, based upon the number of WEC Energy Group shareholder accounts (including accounts in our dividend reinvestment and stock purchase plan), we had approximately 50,000 registered shareholders.

Common Stock Listing and Trading

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

Common Stock Dividends of WEC Energy Group

We review our dividend policy on a regular basis. Subject to any regulatory restrictions or other limitations on the payment of dividends, future dividends will be at the discretion of the Board of Directors and will depend upon, among other factors, earnings, financial condition, and other requirements. For more information on our dividends, including restrictions on the ability of our subsidiaries to pay us dividends, see Note 10, Common Equity.

ITEM 6. SELECTED FINANCIAL DATA

WEC ENERGY GROUP, INC.
COMPARATIVE FINANCIAL DATA AND OTHER STATISTICS

As of or for Year Ended December 31 (in millions, except per share information)	2018	2017 (1)	2016	2015 (2)	2014
Operating revenues	$7,679.5	$7,648.5	$7,472.3	$5,926.1	$4,997.1
Net income attributed to common shareholders	1,059.3	1,203.7	939.0	638.5	588.3
Total assets	33,475.8	31,590.5	30,123.2	29,355.2	14,905.0
Preferred stock of subsidiary	30.4	30.4	30.4	30.4	30.4
Long-term debt (excluding current portion)	9,994.0	8,746.6	9,158.2	9,124.1	4,170.7
Weighted average common shares outstanding					
Basic	315.5	315.6	315.6	271.1	225.6
Diluted	316.9	317.2	316.9	272.7	227.5
Earnings per share					
Basic	$3.36	$3.81	$2.98	$2.36	$2.61
Diluted	$3.34	$3.79	$2.96	$2.34	$2.59
Dividends per share of common stock	$2.21	$2.08	$1.98	$1.74	$1.56

(1) Includes a $206.7 million increase in net income attributed to common shareholders related to a re-measurement of our deferred taxes as a result of the Tax Legislation. See Note 14, Income Taxes, for more information.

(2) Includes the impact of the Integrys acquisition for the last two quarters of 2015.

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

CORPORATE DEVELOPMENTS

Introduction

We are a diversified holding company with natural gas and electric utility operations (serving customers in Wisconsin, Illinois, Michigan, and Minnesota), an approximately 60% equity ownership interest in American Transmission Company LLC (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), Bluewater (which owns underground natural gas storage facilities in Michigan), and a 90% ownership interest in Bishop Hill III (a wind generating facility in Illinois).

In December 2018, WEC Energy Group acquired an 80% ownership interest in Coyote Ridge, a 97.5 MW wind farm under construction in Brookings County, South Dakota. This wind farm is expected to be in service by the end of 2019, and is included in the non-utility energy infrastructure segment. See Note 2, Acquisitions, for more information.

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: reliability; operating efficiency; financial discipline; customer care; and safety.

Reshaping Our Generation Fleet

The planned reshaping of our generation fleet will balance reliability and customer cost with environmental stewardship. Taken as a whole, this plan should reduce costs to customers, preserve fuel diversity, and lower carbon emissions. Generation reshaping includes retiring older fossil fuel generation units, building state-of-the-art natural gas generation, and investing in cost-effective zero-carbon generation with a goal of reducing CO_2 emissions by approximately 40% below 2005 levels by 2030. In addition, we set a new long-term goal of reducing CO_2 emissions by approximately 80% below 2005 levels by 2050. We expect to retire a total of approximately 1,800 MW of coal-fired generation by 2020, and add additional natural gas-fired generating units and renewable generation, including utility-scale solar projects. Our 1,190 MW Pleasant Prairie power plant was retired in April 2018. The physical dismantlement of the Pleasant Prairie power plant will not occur immediately. It may take several years to finalize long-term plans for the site. The jointly owned Edgewater 4 generating unit was retired in September 2018 (our share of the capacity from this plant was 100 MW), and our 200 MW Pulliam power plant was retired in October 2018. See Note 6, Property, Plant, and Equipment, for more information related to these power plant retirements and the planned retirement of the Presque Isle power plant (PIPP).

As part of our commitment to invest in zero-carbon generation, we plan to invest in utility scale solar of up to 350 MW within our Wisconsin segment. Wisconsin Public Service Corporation (WPS) has partnered with an unaffiliated utility to acquire ownership interests in two proposed solar projects in Wisconsin. Badger Hollow Solar Farm will be located in Iowa County, Wisconsin, and Two Creeks Solar Project will be located in Manitowoc County, Wisconsin. Subject to Public Service Commission of Wisconsin (PSCW) approval, WPS will own 100 MW of the output of each project for a total of 200 MW. Commercial operation for both projects is targeted for the end of 2020.

In December 2018, Wisconsin Electric Power Company (WE) received approval from the PSCW for two renewable energy pilot programs. The Solar Now pilot is expected to add 35 MW of solar to WE's portfolio, allowing commercial and industrial customers to site solar arrays on their property. The second program, the Dedicated

Renewable Energy Resource pilot, would allow large commercial and industrial customers to access renewable resources that WE would operate, adding up to 150 MW of renewables to WE's portfolio, and allowing these larger customers to meet their sustainability and renewable energy goals.

As the cost of renewable energy generation installations continues to decline, both the WPS solar projects and the WE pilots have become cost effective opportunities for WEC Energy Group and our customers to participate in renewable energy.

Reliability

We have made significant reliability-related investments in recent years, and plan to continue strengthening and modernizing our generation fleet and distribution networks to further improve reliability. Our investments, coupled with our commitment to operating efficiency and customer care, resulted in We Energies being recognized by PA Consulting Group, an independent consulting firm, as the most reliable utility in the Midwest for the eighth year in a row.

Below are a few examples of reliability projects that are currently underway.

- Upper Michigan Energy Resources Corporation (UMERC), our Michigan electric and natural gas utility, is moving forward with its long-term generation solution for electric reliability in the Upper Peninsula of Michigan. The plan calls for UMERC to construct and operate approximately 180 MW of natural gas-fueled generation located in the Upper Peninsula. The new generation is expected to achieve commercial operation during the second quarter of 2019 and provide the region with affordable, reliable electricity that generates less emissions than the PIPP. Pursuant to a written approval letter received from the Midcontinent Independent System Operator, we must retire PIPP by May 31, 2019.

- The Peoples Gas Light and Coke Company continues to work on its Natural Gas System Modernization Program, which primarily involves replacing old cast and ductile 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.

- WPS continues work on its System Modernization and Reliability Project, which involves modernizing parts of its electric distribution system, including burying or upgrading lines. The project focuses on constructing facilities to improve the reliability of electric service WPS provides to its customers. WPS, WE, and Wisconsin Gas LLC also continue to upgrade their electric and natural gas distribution systems to enhance reliability.

Operating Efficiency

We continually look for ways to optimize the operating efficiency of our company. For example, we are making progress on our Advanced Metering Infrastructure 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 and improving business processes and consolidating our IT infrastructure across all of our companies. We expect these efforts to continue to drive operational efficiency and to put us in 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.

- See Note 2, Acquisitions, for information about our acquisitions of natural gas storage facilities in Michigan and portions of wind energy generation facilities in Wisconsin, Illinois, Nebraska, and South Dakota.

- See Note 3, Dispositions, for information on recent dispositions. In the first quarter of 2017, we sold substantially all of the remaining assets of Bostco LLC, and, in October 2018, Bostco was dissolved. In the second quarter of 2016, we sold certain assets of Wisvest LLC. The sale of Integrys Transportation Fuels, LLC was completed in the first quarter of 2016.

Our investment focus remains in our regulated utility and non-utility energy infrastructure businesses, as well as our investment in ATC. We expect total capital expenditures for our regulated utility and non-utility energy infrastructure businesses to be almost $12.7 billion from 2019 to 2023. Specific projects are discussed in more detail below under Liquidity and Capital Resources.

From 2019 to 2023, we expect capital contributions to ATC and ATC Holdco, LLC to be approximately $250 million. ATC Holdco is a separate entity formed in December 2016 to invest in transmission-related projects outside of ATC's traditional footprint. Capital investments at ATC and ATC Holdco will be funded utilizing these capital contributions, in addition to cash generated from operations

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and debt. We currently forecast that our share of ATC's and ATC Holdco's projected capital expenditures over the next five years will be $1.2 billion inside the traditional ATC footprint and $250 million outside of the traditional ATC footprint.

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 embracing constructive change, demonstrating personal responsibility for results, leveraging our capabilities and expertise, and using creative solutions to meet or exceed our customers’ expectations.

One example of how we obtain feedback from our customers is through our "We Care" calls, through which employees of our utility subsidiaries contact customers after a completed service call. Customer satisfaction is a priority, and making "We Care" calls is one of the main methods we use to gauge our performance to improve customer satisfaction.

Safety

We have a long-standing commitment to both workplace and public safety, and under our "Target Zero" mission, we have an ultimate goal of zero incidents, accidents, and injuries. We also set goals around injury-prevention activities that raise awareness and facilitate conversations about employee safety. 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

Consolidated Earnings

The following table compares our consolidated results:

	Year Ended December 31		
(in millions, except per share data)	2018	2017	2016
Wisconsin	$800.2	$1,055.2	$1,017.8
Illinois	255.8	279.9	261.1
Other states	68.8	54.4	51.2
Non-utility energy infrastructure	365.8	400.5	375.6
Corporate and other	(22.2)	(13.9)	(9.4)
Total operating income	1,468.4	1,776.1	1,696.3
Equity in earnings of transmission affiliates	136.7	154.3	146.5
Other income, net	70.3	73.7	66.6
Interest expense	445.1	415.7	402.7
Income before income taxes	1,230.3	1,588.4	1,506.7
Income tax expense	169.8	383.5	566.5
Preferred stock dividends of subsidiary	1.2	1.2	1.2
Net income attributed to common shareholders	$1,059.3	$1,203.7	$939.0
Diluted earnings per share	$3.34	$3.79	$2.96

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2018 Compared with 2017

Earnings decreased $144.4 million during 2018, compared with 2017. The table below shows the year-over-year income statement impacts associated with the flow through of tax repairs beginning January 1, 2018 and the Tax Legislation signed into law in December 2017. As shown in the table below, the changes related to these items resulted in a decrease in net income attributed to common shareholders of $223.2 million during 2018, compared with 2017. This decrease was driven by the $206.7 million one-time net reduction in income tax expense recorded in 2017 related to the revaluation of our deferred taxes, primarily on our non-utility energy infrastructure and corporate and other segments, as a result of the enactment of the Tax Legislation. See Note 14, Income Taxes, and Note 24, Regulatory Environment, for more information.

(in millions)	2018 Compared with 2017 B (W)	Change Related to Flow Through of Tax Repairs	Change Related to Tax Legislation	Remaining Change B (W)
Wisconsin	$ (255.0)	$ (165.9)	$ (142.2)	$ 53.1
Illinois	(24.1)	—	(29.5)	5.4
Other states	14.4	—	(8.0)	22.4
Non-utility energy infrastructure	(34.7)	—	(50.4)	15.7
Corporate and other	(8.3)	—	—	(8.3)
Total operating income	(307.7)	(165.9)	(230.1)	88.3
Equity in earnings of transmission affiliates	(17.6)	—	(34.3)	16.7
Other income, net	(3.4)	—	—	(3.4)
Interest expense	(29.4)	—	—	(29.4)
Income before income taxes	(358.1)	(165.9)	(264.4)	72.2
Income tax expense	213.7	165.9	41.2	6.6
Preferred stock dividends of subsidiary	—	—	—	—
Net income attributed to common shareholders	$ (144.4)	$ —	$ (223.2)	$ 78.8

Absent the effect of the Tax Legislation, earnings increased by $78.8 million. The significant factors impacting this $78.8 million increase in earnings were:

- A $53.1 million remaining increase in operating income at the Wisconsin segment, driven by an increase in electric and natural gas margins related to higher retail sales volumes as a result of favorable weather and higher weather-normalized use per customer. This increase in margins was partially offset by higher operating expenses during 2018, which were driven by the earnings sharing mechanisms in place at our Wisconsin utilities. See Note 24, Regulatory Environment, for more information on our earnings sharing mechanisms.

- A $22.4 million remaining increase in operating income at the other states segment. The increase was driven by higher natural gas margins, which were primarily a result of the colder winter weather in 2018 as well as customer growth and an interim rate increase at MERC. See Note 24, Regulatory Environment, for more information on the interim rate increase.

- A $16.7 million remaining increase in earnings from our ownership interests in transmission affiliates. The increase was driven by expenses recorded in 2017 by ATC related to the refund ATC was required to provide customers as a result of its FERC financial audit. Continued capital investment by our transmission affiliates also contributed to the increase.

- A $15.7 million remaining increase in operating income at the non-utility energy infrastructure segment, primarily driven by the inclusion of a full year of operations of Bluewater following its acquisition on June 30, 2017.

These increases in earnings were partially offset by a $29.4 million increase in interest expense, driven by higher debt balances, primarily used to fund capital investments, and higher interest rates on both short-term and long-term debt.

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2017 Compared with 2016

Earnings increased $264.7 million during 2017, compared with 2016. The significant factors impacting the increase in earnings were:

- A $206.7 million one-time net reduction in income tax expense related to the revaluation of our deferred taxes primarily on our non-utility energy infrastructure and corporate and other segments at December 31, 2017, as a result of the enactment of the Tax Legislation.

- A $37.4 million pre-tax increase in operating income at the Wisconsin segment, driven by lower operating expenses. A decrease in electric margins, driven by lower sales volumes, partially offset the decrease in operating expenses.

- A $24.9 million pre-tax increase in operating income at the non-utility energy infrastructure segment. The increase was driven by higher revenues in connection with capital additions to the plants We Power owns and leases to WE and the inclusion of the operations of Bluewater following its acquisition on June 30, 2017.

- An $18.8 million pre-tax increase in operating income at the Illinois segment. The increase was driven by higher natural gas margins at PGL due to continued capital investment in the SMP project under its QIP rider and lower operating expenses.

Non-GAAP Financial Measures

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

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

Our electric margins and natural gas margins may not be comparable to similar measures presented by other companies. Furthermore, these measures are not intended to replace operating income as determined in accordance with GAAP as an indicator of our segment operating performance. Operating income for each of the last three fiscal years for each of our segments is presented in the “Consolidated Earnings” table above.

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

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Wisconsin Segment Contribution to Operating Income

For the periods presented in this Annual Report on Form 10-K, our Wisconsin operations included operations of WE, WG, and WPS for all periods, and operations for UMERC beginning January 1, 2017, due to the transfer of customers and assets in the Upper Peninsula of Michigan from WE and WPS.

	Year Ended December 31		
(in millions)	2018	2017	2016
Electric revenues	$4,438.9	$4,559.0	$4,628.1
Fuel and purchased power	1,418.1	1,467.0	1,473.1
Total electric margins	3,020.8	3,092.0	3,155.0
Natural gas revenues	1,355.8	1,270.2	1,177.6
Cost of natural gas sold	792.1	701.8	621.2
Total natural gas margins	563.7	568.4	556.4
Total electric and natural gas margins	3,584.5	3,660.4	3,711.4
Other operation and maintenance	2,076.1	1,923.2	2,034.6
Depreciation and amortization	546.6	523.9	496.6
Property and revenue taxes	161.6	158.1	162.4
Operating income	$800.2	$1,055.2	$1,017.8

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

	Year Ended December 31		
(in millions)	2018	2017	2016
Operation and maintenance not included in line items below	$769.5	$833.3	$891.1
We Power (1)	506.9	513.0	513.2
Transmission (2)	420.7	407.4	423.2
Transmission expense related to the flow through of tax repairs (3)	77.8	—	—
Transmission expense related to Tax Legislation (4)	67.7	—	—
Regulatory amortizations and other pass through expenses (5)	159.1	158.1	157.4
Earnings sharing mechanisms (6)	67.5	2.9	24.4
Other	6.9	8.5	25.3
Total other operation and maintenance	$2,076.1	$1,923.2	$2,034.6

(1) Represents costs associated with the We Power generation units, including operating and maintenance costs incurred by WE, as well as the lease payments that are billed from We Power to WE and then recovered in WE's rates. During 2018, 2017, and 2016, $485.3 million, $535.1 million, and $528.4 million, respectively, of both lease and operating and maintenance costs were billed to or incurred by WE, with the difference in costs billed or incurred and expenses recognized, either deferred or deducted from the regulatory asset.

(2) The PSCW has approved escrow accounting for ATC and MISO network transmission expenses for our Wisconsin electric utilities. As a result, WE and WPS defer as a regulatory asset or liability the differences between actual transmission costs and those included in rates until recovery or refund is authorized in a future rate proceeding. During 2018, 2017, and 2016, $438.2 million, $451.4 million, and $486.0 million, respectively, of costs were billed to our electric utilities by transmission providers.

(3) Represents additional transmission expense associated with WE's flow through of tax benefits of its repair-related deferred tax liabilities starting in 2018, in accordance with a settlement agreement with the PSCW, to maintain

certain regulatory asset balances at their December 31, 2017 levels. See Note 24, Regulatory Environment, for more information.

(4) Represents additional transmission expense associated with the May 2018 PSCW order requiring WE to use 80% of its current 2018 tax benefit, including the amortization associated with the revaluation of deferred taxes, to reduce its transmission regulatory asset balance. See Note 24, Regulatory Environment, for more information.

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

(6) See Note 24, Regulatory Environment, for more information about our earnings sharing mechanisms.

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

	Year Ended December 31 MWh (in thousands)		
Electric Sales Volumes	2018	2017	2016
Customer class			
Residential	11,195.0	10,636.3	10,998.9
Small commercial and industrial *	13,186.7	12,932.1	13,113.1
Large commercial and industrial *	12,946.5	12,822.0	13,418.6
Other	169.0	175.6	172.2
Total retail *	37,497.2	36,566.0	37,702.8
Wholesale	3,612.7	3,768.0	3,704.6
Resale	6,019.3	9,000.3	8,761.6
Total sales in MWh *	47,129.2	49,334.3	50,169.0

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

	Year Ended December 31 Therms (in millions)		
Natural Gas Sales Volumes	2018	2017	2016
Customer class			
Residential	1,131.1	1,028.3	1,004.0
Commercial and industrial	733.1	654.7	621.4
Total retail	1,864.2	1,683.0	1,625.4
Transport	1,411.5	1,316.4	1,270.6
Total sales in therms	3,275.7	2,999.4	2,896.0

	Year Ended December 31 Degree Days		
Weather	2018	2017	2016
WE and WG (1)			
Heating (6,515 normal)	6,685	5,908	6,068
Cooling (731 normal)	929	772	991
WPS (2)			
Heating (7,324 normal)	7,554	6,942	6,715
Cooling (507 normal)	678	450	572
UMERC (3)			
Heating (8,326 normal)	8,611	8,145	N/A
Cooling (325 normal)	478	235	N/A

(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.

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2018 Compared with 2017

Electric Utility Margins

Electric utility margins at the Wisconsin segment decreased $71.2 million during 2018, compared with 2017. The significant factors impacting the lower electric utility margins were:

- An $88.1 million decrease in margins associated with WE's flow through of tax benefits of its repair-related deferred tax liabilities starting in 2018, in accordance with a settlement agreement with the PSCW to maintain certain regulatory assets at their December 31, 2017 levels. See Note 24, Regulatory Environment, for more information.

- A $30.0 million decrease in margins related to savings from the Tax Legislation that we are required to return to customers through bill credits or reductions in other regulatory assets. See Note 14, Income Taxes, and Note 24, Regulatory Environment, for more information.

- A $29.7 million decrease in wholesale margins driven both by lower sales volumes and reduced capacity rates due in part to the Tax Legislation.

- A $9.1 million year-over-year negative impact from collections of fuel and purchased power costs compared with costs approved in rates. 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 less than a 2% price variance from the costs included in rates, and the remaining variance that exceeds the 2% variance is deferred.

These decreases in electric utility margins were partially offset by:

- A $67.5 million increase related to higher retail sales volumes during 2018, primarily driven by favorable weather and higher overall use per retail customer due in part to a stronger economy. Colder winter weather and a warmer summer in 2018 contributed to the increase. As measured by heating degree days, 2018 was 13.2% and 8.8% colder than 2017 in the Milwaukee and Green Bay areas, respectively. As measured by cooling degree days, 2018 was 20.3% and 50.7% warmer than 2017 in the Milwaukee area and Green Bay area, respectively.

- A $25.9 million increase related to SSR payments WE refunded to MISO in 2017 as directed by a FERC order received in October 2017. The FERC order reduced the costs eligible for reimbursement to WE for the operation and maintenance of its PIPP units under an SSR agreement between MISO and WE. A portion of these payments was returned to WE through the MISO allocation process and reduced transmission expense in 2017 as discussed below.

Natural Gas Utility Margins

Natural gas utility margins at the Wisconsin segment decreased $4.7 million during 2018, compared with 2017. The most significant factor impacting the lower natural gas utility margins was $39.0 million of savings from the Tax Legislation that we are required to return to customers through bill credits. See Note 14, Income Taxes, and Note 24, Regulatory Environment, for more information. This decrease in natural gas utility margins was partially offset by a $34.5 million increase related to higher sales volumes, primarily driven by colder winter weather, customer growth, and higher use per retail customer due in part to a stronger economy.

Operating Income

Operating income at the Wisconsin segment decreased $255.0 million during 2018, compared with 2017. This decrease was driven by $179.1 million of higher operating expenses (which include other operation and maintenance, depreciation and amortization, and property and revenue taxes), and the $75.9 million decrease in margins discussed above.

The significant factors impacting the increase in operating expenses during 2018, compared with 2017, were:

- A $77.8 million increase in transmission expense related to the flow through of tax repairs, as discussed in the other operation and maintenance table above.

- A $67.7 million increase in transmission expense associated with the May 2018 order from the PSCW related to our required treatment of the benefits associated with the Tax Legislation, as discussed in the other operation and maintenance table above.

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- A $64.6 million increase in expense related to the earnings sharing mechanisms in place at our Wisconsin utilities. See Note 24, Regulatory Environment, for more information.

- A $22.7 million increase in depreciation and amortization, driven by an increase in capital expenditures as we continue to execute on our capital plan. This increase in depreciation and amortization was partially offset by a decrease related to the reduction of certain WPS regulatory deferrals as a result of the PSCW's May 2018 order addressing the Tax Legislation.

- A $13.3 million increase in transmission expense in 2018, driven by lower expense in 2017 related to a FERC order received in October 2017 to reduce SSR costs related to PIPP. A portion of the payments we initially refunded to MISO were returned to us, as discussed under electric utility margins.

These increases in operating expenses were partially offset by a $69.9 million decrease in expenses across all of our plants, in part due to the retirements of the Pleasant Prairie power plant in April 2018, Edgewater Unit 4 in September 2018, and Pulliam Units 7 and 8 in October 2018. This resulted in lower maintenance and labor costs during 2018. See Note 6, Property, Plant, and Equipment, for more information on the plant retirements.

2017 Compared with 2016

Electric Utility Margins

Electric utility margins at the Wisconsin segment decreased $63.0 million during 2017, compared with 2016. The significant factors impacting the lower electric utility margins were:

- A $72.6 million decrease related to lower sales volumes during 2017, primarily driven by unfavorable weather as well as lower overall retail use per customer. Cooler summer and warmer winter weather in 2017, and an additional day of sales during 2016 due to leap year, contributed to the decrease. As measured by cooling degree days, 2017 was 22.1% and 21.3% cooler than 2016 in the Milwaukee and Green Bay areas, respectively. As measured by heating degree days, 2017 was 2.6% warmer than 2016 in the Milwaukee area.

- A $25.9 million decrease related to SSR payments WE refunded to MISO as directed by a FERC order received in October 2017. The FERC order reduced the costs eligible for reimbursement to WE for the operation and maintenance of its PIPP units under an SSR agreement between MISO and WE. A portion of these payments was returned to WE through the MISO allocation process and reduced transmission expense as discussed below. See Note 24, Regulatory Environment, for more information.

- A $3.5 million decrease in steam margins driven by the sale of the MCPP in April 2016. See Note 3, Dispositions, for more information.

- A $3.3 million period-over-period negative impact from collections of fuel and purchased power costs compared with costs approved in rates. 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 less than a 2% price variance from the costs included in rates, and the remaining variance that exceeds the 2% variance is deferred.

These decreases in electric utility margins were partially offset by $36.5 million of lower capacity payments to a counterparty during 2017, related to improved contract terms.

Natural Gas Utility Margins

Natural gas utility margins at the Wisconsin segment increased $12.0 million during 2017, compared with 2016. The most significant factor impacting the higher natural gas utility margins was higher retail sales volumes, primarily driven by higher overall retail use per customer and customer growth. The higher retail sales volumes in 2017 were partially offset by an additional day of sales during 2016 due to leap year.

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Operating Income

Operating income at the Wisconsin segment increased $37.4 million during 2017, compared with 2016. This increase was driven by $88.4 million of lower operating expenses (which include other operation and maintenance, depreciation and amortization, and property and revenue taxes), partially offset by the $51.0 million net decrease in margins discussed above.

The Wisconsin segment experienced lower overall operating expenses related to synergy savings resulting from the Integrys acquisition. The significant factors impacting the decrease in operating expenses during 2017, compared with 2016, which were due in part to synergy savings, were:

- A $29.1 million decrease in electric and natural gas distribution expenses, primarily related to lower metering costs and other cost savings.

- A $21.5 million decrease in expenses related to the earnings sharing mechanisms in place at WE and WG. See Note 24, Regulatory Environment, for more information.

- A $16.8 million decrease in expenses related to charitable projects supporting our customers and the communities within our service territories.

- A $15.8 million decrease in transmission expenses, driven by a FERC order received in October 2017 to reduce SSR costs related to PIPP. A portion of the payments we initially refunded to MISO were returned to us, as discussed under electric utility margins.

- An $11.5 million decrease in expenses related to an information technology project completed in 2016 to improve the billing, call center, and credit collection functions of certain WEC Energy Group subsidiaries. Lower expenses were due in part to a decrease in asset usage charges from WBS, driven by the transfer of this project from WBS to certain WEC Energy Group subsidiaries, including WPS, during 2017. The portion of these lower expenses related to the transfer was offset through higher depreciation and amortization, discussed below.

- A $10.5 million decrease in operation and maintenance expenses at our plants, primarily related to the seasonal operation of the Pleasant Prairie power plant during 2017, lower operating costs at the plants, the timing of planned outages and maintenance, and the sale of the MCPP in April 2016. See Note 3, Dispositions, for more information on the sale of the MCPP. These decreases were partially offset by severance costs related to planned plant retirements. See Note 6, Property, Plant, and Equipment, for more information.

- A $5.7 million decrease in customer service expenses, partially related to lower contracted meter reading rates and cost savings.

These decreases in operating expenses were partially offset by:

- A $27.3 million increase in depreciation and amortization, driven by an overall increase in utility plant in service, the completion of the ReACT™ multi-pollutant control system at Weston Unit 3 during the fourth quarter of 2016, and WBS's transfer of the information technology project to WPS during 2017.

- A $10.9 million gain recorded in April 2016 related to the sale of the MCPP.

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Illinois Segment Contribution to Operating Income

Since the majority of PGL and NSG customers use natural gas for heating, operating income is sensitive to weather and is generally higher during the winter months.

	Year Ended December 31		
(in millions)	2018	2017	2016
Natural gas revenues	$1,400.0	$1,355.5	$1,242.2
Cost of natural gas sold	480.5	438.9	365.2
Total natural gas margins	919.5	916.6	877.0
Other operation and maintenance	472.3	464.2	463.6
Depreciation and amortization	170.3	152.6	134.0
Property and revenue taxes	21.1	19.9	18.3
Operating income	$255.8	$279.9	$261.1

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

	Year Ended December 31		
(in millions)	2018	2017	2016
Operation and maintenance not included in the line items below	$372.9	$361.5	$363.8
Riders *	95.3	98.1	82.3
Regulatory amortizations *	(1.4)	1.0	2.7
Other	5.5	3.6	14.8
Total other operation and maintenance	$472.3	$464.2	$463.6

* These riders and regulatory amortizations are substantially offset in margins and therefore do not have a significant impact on operating income.

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

	Therms (in millions)		
Natural Gas Sales Volumes	2018	2017	2016
Customer Class			
Residential	896.2	759.6	771.8
Commercial and industrial	358.3	313.9	321.4
Total retail	1,254.5	1,073.5	1,093.2
Transport	905.1	853.4	855.3
Total sales in therms	2,159.6	1,926.9	1,948.5

	Degree Days		
Weather *	2018	2017	2016
Heating (6,059 normal)	6,327	5,470	5,713

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

2018 Compared with 2017

Natural Gas Utility Margins

Natural gas utility margins at the Illinois segment, net of the $2.8 million impact of the riders referenced in the table above, increased $5.7 million during 2018, compared with 2017. The increase was primarily driven by an increase in revenue at PGL due to continued capital investment in the SMP project under its QIP rider. PGL currently recovers the costs related to the SMP through a surcharge on customer bills pursuant to an ICC approved QIP rider, which is in effect through 2023. This increase was substantially offset by a decrease in margins related to savings from the Tax Legislation that we are required to return to customers through the VITA. See Note 14, Income Taxes, and Note 24, Regulatory Environment, for more information.

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Operating Income

Operating income at the Illinois segment decreased $24.1 million during 2018, compared with 2017. This decrease was driven by $29.8 million of higher operating expenses (which include other operation and maintenance, depreciation and amortization, and property and revenues taxes), net of the impact of the riders referenced in the table above, partially offset by the $5.7 million increase in margins discussed above.

The significant factors impacting the increase in operating expenses during 2018, compared with 2017, were:

- A $17.7 million increase in depreciation expense primarily driven by PGL's continued capital investment in the SMP project.

- An $11.4 million increase in natural gas maintenance costs related to our Illinois utilities' distribution systems.

2017 Compared with 2016

Natural Gas Utility Margins

Natural gas utility margins at the Illinois segment, net of the $15.8 million impact of the riders referenced in the table above, increased $23.8 million during 2017, compared with 2016. The increase was primarily driven by an increase in revenue at PGL due to continued capital investment in the SMP project under its QIP rider.

Operating Income

Operating income at the Illinois segment increased $18.8 million during 2017, compared with 2016. This increase was due to the $23.8 million increase in margins discussed above, partially offset by $5.0 million of higher operating expenses (which include other operation and maintenance, depreciation and amortization, and property and revenues taxes), net of the impact of the riders referenced in the table above.

The significant factors impacting the increase in operating expenses during 2017, compared with 2016, were:

- An $18.6 million increase in depreciation and amortization expense, driven by continued capital investment at PGL in the SMP project and the transfer of an information technology project to PGL and NSG in 2017. This information technology project was created to improve the billing, call center, and credit collection facilities of certain WEC subsidiaries.

- An increase in natural gas distribution expenses, driven by increased repair activity in 2017.

These increases were partially offset by:

- A $9.8 million decrease in expenses related to charitable projects supporting our customers and the communities within our service territories.

- A $6.5 million decrease in benefit related expenses driven by lower pension costs.

- A $6.0 million decrease in expenses related to the information technology project completed in 2016 to improve certain functions of some WEC Energy Group subsidiaries. Lower expenses were due in part to a decrease in asset usage charges from WBS, driven by the transfer of this project from WBS to certain WEC Energy Group subsidiaries, including PGL and NSG, during 2017. The portion of these lower expenses related to the transfer are offset through higher depreciation and amortization, discussed above.

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Other States Segment Contribution to Operating Income

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

	Year Ended December 31		
(in millions)	2018	2017	2016
Natural gas revenues	$438.2	$411.2	$376.5
Cost of natural gas sold	232.8	215.3	182.3
Total natural gas margins	205.4	195.9	194.2
Other operation and maintenance	101.0	101.1	108.8
Depreciation and amortization	24.1	24.8	21.1
Property and revenue taxes	11.5	15.6	13.1
Operating income	$68.8	$54.4	$51.2

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

	Year Ended December 31		
(in millions)	2018	2017	2016
Operation and maintenance not included in line items below	$76.1	$78.1	$85.1
Regulatory amortizations and other pass through expenses *	24.8	23.0	23.6
Other	0.1	—	0.1
Total other operation and maintenance	$101.0	$101.1	$108.8

* Regulatory amortizations and other pass through expenses are substantially offset in margins and therefore do not have a significant impact on operating income.

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

	Therms (in millions)		
Natural Gas Sales Volumes	2018	2017	2016
Customer Class			
Residential	336.1	285.6	278.5
Commercial and industrial	218.5	199.4	178.2
Total retail	554.6	485.0	456.7
Transport	738.7	693.3	696.2
Total sales in therms	1,293.3	1,178.3	1,152.9

	Degree Days		
Weather *	2018	2017	2016
MERC			
Heating (7,864 normal)	8,490	7,625	7,188
MGU			
Heating (6,240 normal)	6,368	5,707	5,712

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

2018 Compared with 2017

Natural Gas Utility Margins

Natural gas utility margins increased $9.5 million during 2018, compared with 2017. The increase was primarily driven by colder winter weather as well as customer growth and an interim rate increase at MERC, partially offset by an $8.0 million decrease in margins related to savings from the Tax Legislation that we are required to return to customers through bill credits or reductions in

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future rates, related to the Tax Legislation signed into law in December 2017. See Note 14, Income Taxes, and Note 24, Regulatory Environment, for more information.

Operating Income

Operating income at the other states segment increased $14.4 million during 2018, compared with 2017. The increase was due to the $9.5 million increase in margins discussed above and a $4.9 million decrease in operating expenses (which include other operation and maintenance, depreciation and amortization, and property and revenue taxes). The decrease in operating expenses was primarily driven by lower property and revenue taxes resulting from a favorable judgment that MERC received related to a property tax matter. Because property taxes were under-recovered from rate payers in prior years, MERC will receive $4.8 million of the judgment, with any remaining amount passed back to customers through the property tax tracker that is now in place. The property tax tracker will allow for any future over- or under-recovered property tax expense to be recorded as a regulatory asset or liability. The balance in the regulatory asset or liability account will be reflected in the revenue requirement calculation in MERC's next general rate case.

2017 Compared with 2016

Operating Income

Operating income at the other states segment increased $3.2 million during 2017, compared with 2016. The increase was primarily driven by lower operation and maintenance expense due to effective cost control measures, partially offset by higher depreciation and amortization due to an increase in capital investment.

Non-Utility Energy Infrastructure Segment Contribution to Operating Income

	Year Ended December 31		
(in millions)	2018	2017	2016
Operating income	$365.8	$400.5	$375.6

2018 Compared with 2017

Operating income at the non-utility energy infrastructure segment decreased $34.7 million during 2018, compared with 2017. The decrease was driven by a $50.3 million decrease in revenue related to the Tax Legislation signed into law in December 2017. As a result of the Tax Legislation, the lease payments charged by We Power to WE were reduced to account for the lower tax rate. The reduction in the lease payments was offset by a decrease in income tax expense, resulting in no impact on net income. See Note 14, Income Taxes for more information. Partially offsetting the impact of the Tax Legislation was a $22.0 million contribution to operating income from Bluewater in 2018, compared to an $8.4 million contribution in 2017. Bluewater was acquired on June 30, 2017. See Note 2, Acquisitions, for more information.

2017 Compared with 2016

Operating income at the non-utility energy infrastructure segment increased $24.9 million during 2017, compared with 2016. Bluewater, which was acquired on June 30, 2017, contributed $8.4 million to 2017 operating income. The remaining increase of $16.5 million was driven by higher revenues in connection with capital additions to the plants We Power owns and leases to WE.

Corporate and Other Segment Contribution to Operating Income

	Year Ended December 31		
(in millions)	2018	2017	2016
Operating loss	$(22.2)	$(13.9)	$(9.4)

2018 Compared with 2017

The operating loss at the corporate and other segment increased $8.3 million during 2018, compared with 2017, driven by a $4.0 million impairment loss recorded in 2018 on certain nonregulated assets that were acquired as a part of the acquisition of Integrys. Also contributing to the increase in operating loss was the transfer of assets from WBS, our centralized services company, to our regulated utilities in mid-2017 and early 2018. As a result of these transfers, the return on these assets is now recognized within our regulated utility operations.

2017 Compared with 2016

The operating loss at the corporate and other segment increased $4.5 million during 2017, compared with 2016, driven by the transfer of assets from WBS to our regulated utilities in mid-2017. As a result of these transfers, the return on these assets is now recognized within our regulated utility operations. Partially offsetting this increase in operating loss was the impact from $3.5 million of costs incurred in 2016 related to the acquisition of Integrys.

Electric Transmission Segment Operations

	Year Ended December 31		
(in millions)	2018	2017	2016
Equity in earnings of transmission affiliates	$136.7	$154.3	$146.5

2018 Compared with 2017

Earnings from our ownership interests in transmission affiliates decreased $17.6 million during 2018, compared with 2017, driven by the Tax Legislation signed into law in December 2017. The $34.3 million decrease in our equity earnings from ATC due to the Tax Legislation did not affect our net income as it was offset by an equal reduction in our income tax expense. See Note 14, Income Taxes, for more information. The negative impact of the Tax Legislation was partially offset by expenses recorded in 2017 by ATC related to the refund ATC was required to provide customers as a result of its FERC financial audit. Continued capital investment by our transmission affiliates also increased our equity earnings year over year.

2017 Compared with 2016

Earnings from our ownership interests in transmission affiliates increased $7.8 million during 2017, compared with 2016. The lower earnings during 2016 as compared to 2017 were primarily the result of an ALJ recommendation related to the FERC ROE complaints. See Factors Affecting Results, Liquidity, and Capital Resources – Other Matters – American Transmission Company Allowed Return on Equity Complaints for more information.

Consolidated Other Income, Net

	Year Ended December 31		
(in millions)	2018	2017	2016
AFUDC – Equity	$15.2	$11.4	$25.1
Non-service credit (cost) components of net periodic benefit costs	26.0	9.1	(14.2)
Gain on repurchase of notes	—	—	23.6
Other, net	29.1	53.2	32.1
Other income, net	$70.3	$73.7	$66.6

2018 Compared with 2017

Other income, net decreased $3.4 million during 2018, compared with 2017. A decrease of $23.3 million was due to $1.8 million of net losses from investments held in our rabbi trust during 2018, compared with net gains of $21.5 million during 2017. Partially offsetting this decrease was a $16.9 million increase in income due to higher net credits from the non-service components of our net periodic pension and OPEB costs. See Note 18, Employee Benefits, for more information on our benefit costs.

2017 Compared with 2016

Other income, net increased $7.1 million during 2017, compared with 2016, driven by the year-over-year increase in income from the non-service components of our net periodic pension and OPEB costs. Also contributing to the increase were higher gains on investments held in our rabbi trust during 2017, compared with 2016. These increases were partially offset by a $23.6 million gain recorded in February 2016 on the repurchase of a portion of Integrys's 2006 Junior Notes at a discount and lower AFUDC in 2017

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largely due to the ReACT™ emission control technology project at Weston Unit 3 going into service during the fourth quarter of 2016.

Consolidated Interest Expense

	Year Ended December 31		
(in millions)	2018	2017	2016
Interest expense	$445.1	$415.7	$402.7

2018 Compared with 2017

Interest expense increased $29.4 million during 2018, compared with 2017. The increase was primarily due to higher debt balances and higher interest rates on both short-term and long-term debt. This increase in debt balances was primarily related to continued capital investments.

2017 Compared with 2016

Interest expense increased $13.0 million during 2017, compared with 2016. The increase was primarily due to higher debt levels in 2017 to fund continued capital investments and lower capitalized interest during 2017, primarily as a result of the completion of the ReACT™ emission control project in 2016.

Consolidated Income Tax Expense

	Year Ended December 31		
	2018	2017	2016
Effective tax rate	13.8%	24.1%	37.6%

2018 Compared with 2017

Our effective tax rate was 13.8% in 2018, compared to 24.1% in 2017. This decrease was primarily due to the flow through of tax repairs in connection with the Wisconsin rate settlement. See Note 14, Income Taxes, and Note 24, Regulatory Environment, for more information.

We expect our 2019 annual effective tax rate to be between 10.5% and 11.5%, which includes an estimated 9.5% effective tax rate benefit due to the flow through of tax repairs in connection with the Wisconsin rate settlement. Excluding the impact of the tax repairs, the expected 2019 range would be between 20% and 21%.

2017 Compared with 2016

Our effective tax rate was 24.1% in 2017, compared to 37.6% in 2016. The 13.5% decrease in the effective tax rate was driven by a $206.7 million one-time net reduction in income tax expense related to the revaluation of our deferred taxes primarily on our non-utility energy infrastructure and corporate and other segments at December 31, 2017, as a result of the enactment of the Tax Legislation. Our effective tax rate in 2017 excluding the one-time net reduction in income tax expense due to revaluation of our deferred taxes was 37.2%.

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LIQUIDITY AND CAPITAL RESOURCES

Cash Flows

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

(in millions)	2018	2017	2016	Change in 2018 Over 2017	Change in 2017 Over 2016
Cash provided by (used in):					
Operating activities	$2,445.5	$2,078.6	$2,103.8	$366.9	$(25.2)
Investing activities	(2,384.4)	(2,254.1)	(1,354.2)	(130.3)	(899.9)
Financing activities	26.4	161.4	(845.7)	(135.0)	1,007.1

Operating Activities

2018 Compared with 2017

Net cash provided by operating activities increased $366.9 million during 2018, compared with 2017, driven by:

- A $396.1 million increase in cash related to higher overall collections from customers, primarily due to favorable weather during 2018, compared with 2017.

- A $97.5 million increase in cash from lower payments for other operation and maintenance expenses. During 2018, our payments related to plant maintenance and labor costs decreased, due in part to the retirements in 2018 of the Pleasant Prairie power plant, Edgewater Unit 4, and Pulliam Units 7 and 8. See Note 6, Property, Plant, and Equipment, for more information about the retirement of our plants. In addition, our payments for transmission costs decreased during 2018.

These increases in net cash provided by operating activities were partially offset by a $127.6 million decrease in cash resulting from higher payments during 2018, compared with 2017, for natural gas we purchased at the end of 2017 and during 2018 to meet the requirements of our customers during the colder winter weather.

2017 Compared with 2016

Net cash provided by operating activities decreased $25.2 million during 2017, compared with 2016, driven by:

- A $217.9 million decrease in cash resulting from higher payments for natural gas and fuel and purchased power in 2017, primarily due to higher commodity prices. The average per-unit cost of natural gas sold increased 13.6% during 2017, compared with 2016.

- A $91.8 million increase in contributions and payments to our pension and OPEB plans during 2017, compared with 2016.

- A $34.5 million net decrease in cash received from income taxes during 2017, compared with 2016. This decrease in cash was primarily due to the extension of bonus depreciation in December 2015, which resulted in the receipt of an income tax refund during 2016.

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A $26.5 million decrease in cash due to higher collateral requirements during 2017, compared with 2016, driven by a decrease in the fair value of our derivative instruments. See Note 16, Derivative Instruments, for more information.

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

- A $158.7 million increase in cash from lower payments for operating and maintenance expenses. During 2017, our payments related to transmission, electric and natural gas distribution, charitable projects, employee benefits, and electric generation decreased.

- A $129.2 million increase in cash related to higher overall collections from customers, primarily due to higher commodity prices during 2017, compared with 2016.

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- A $49.6 million increase in cash distributions provided by ATC during 2017, compared with 2016.

Investing Activities

2018 Compared with 2017

Net cash used in investing activities increased $130.3 million during 2018, compared with 2017, driven by:

- The acquisition of a 90% ownership interest in Bishop Hill III during 2018 for $162.9 million, which is net of restricted cash acquired of $4.5 million. See Note 2, Acquisitions, for more information.

- A $156.2 million increase in cash paid for capital expenditures during 2018, compared with 2017, which is discussed in more detail below.

- The acquisition of a portion of Forward Wind Energy Center during April 2018 for $77.1 million. See Note 2, Acquisitions, for more information.

- The acquisition of an 80% ownership interest in Coyote Ridge during December 2018 for $61.4 million. See Note 2, Acquisitions, for more information.

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

- The acquisition of Bluewater during June 2017 for $226.0 million. See Note 2, Acquisitions, for more information.

- A $56.1 million decrease in our capital contributions to ATC and ATC Holdco during 2018, compared with 2017, due to the restructuring of DATC's ownership. During the fourth quarter of 2017, ATC Holdco purchased ATC's ownership interest in DATC, which resulted in higher capital contributions during 2017. Our capital contributions also decreased due to the refunds ATC paid in 2017 as a result of the ATC ROE complaints filed with the FERC, which were partially funded by capital contributions. See Factors Affecting Results, Liquidity, and Capital Resources – Other Matters – American Transmission Company Allowed Return on Equity Complaints for more information on the ATC ROE complaints.

- A $48.6 million net increase in restricted cash during 2018, compared with 2017, due to a $109.9 million increase in the proceeds received from the sale of investments held in the Integrys rabbi trust, partially offset by a $61.3 million increase in the purchase of investments held in the rabbi trust.

2017 Compared with 2016

Net cash used in investing activities increased $899.9 million during 2017, compared with 2016, driven by:

- A $535.8 million increase in cash paid for capital expenditures during 2017, compared with 2016, which is discussed in more detail below.

- The acquisition of Bluewater during June 2017 for $226.0 million. See Note 2, Acquisitions, for more information.

- A $142.3 million decrease in the proceeds received from the sale of assets and businesses during 2017, compared with 2016. See Note 3, Dispositions, for more information.

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A $67.3 million increase in our capital contributions to ATC and ATC Holdco during 2017, compared with 2016, due to the continued investment in equipment and facilities by ATC to improve reliability and the restructuring of DATC's ownership. In addition, the refunds paid by ATC in 2017 and ATC's lower earnings in 2016, as a result of the ATC ROE complaints filed with the FERC, also contributed to the year-over-year increase in our capital contributions.

These increases in net cash used in investing activities were partially offset by a $62.5 million increase in restricted cash during 2017, compared with 2016, due to a $55.5 million decrease in the purchase of investments held in the Integrys rabbi trust and a $7.0 million increase in the proceeds received from the sale of investments held in the rabbi trust.

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Capital Expenditures

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

Reportable Segment (in millions)	2018	2017	2016	Change in 2018 Over 2017	Change in 2017 Over 2016
Wisconsin	$1,389.0	$1,152.3	$910.9	$236.7	$241.4
Illinois	547.1	545.2	293.2	1.9	252.0
Other states	103.6	74.5	59.5	29.1	15.0
Non-utility energy infrastructure	36.3	35.4	62.3	0.9	(26.9)
Corporate and other	39.7	152.1	97.8	(112.4)	54.3
Total capital expenditures	$2,115.7	$1,959.5	$1,423.7	$156.2	$535.8

2018 Compared with 2017

The increase in cash paid for capital expenditures at the Wisconsin segment during 2018, compared with 2017, was primarily driven by the construction of the new natural gas-fired generation facility in the Upper Peninsula of Michigan and an advanced metering infrastructure program. An information technology project created to improve WE's and WG's billing, call center, and credit collection functions, a natural gas lateral project at WPS's Fox Energy Center, and various other software projects also contributed to the increase in our capital expenditures.

The increase in cash paid for capital expenditures at the other states segment during 2018, compared with 2017, was primarily driven by upgrades to MERC's natural gas distribution systems.

The decrease in cash paid for capital expenditures at the corporate and other segment during 2018, compared with 2017, was primarily driven by the implementation of a new enterprise resource planning system during the first quarter of 2018. The 2017 completion of an information technology project created to improve the billing, call center, and credit collection functions of the Integrys subsidiaries reduced our capital expenditures as well. Various other software projects, the majority of which were completed during 2017, also contributed to the decrease in our capital expenditures.

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

2017 Compared with 2016

The increase in cash paid for capital expenditures at the Wisconsin segment during 2017, compared with 2016, was primarily driven by upgrades to our electric and natural gas distribution systems, including main replacement projects and an advanced metering infrastructure program, as well as WPS's SMRP and various projects at the OCPP. These increases in capital expenditures were partially offset by reduced construction activity at WPS related to the ReACT™ emission control technology project at Weston Unit 3, which was completed in 2016, and the combustion turbine project at the Fox Energy Center, which was completed in June 2017.

The increase in cash paid for capital expenditures at the Illinois segment during 2017, compared with 2016, was primarily driven by increased construction activity related to PGL's SMP, its natural gas storage field, and a project to relocate one of PGL's service facilities.

The increase in cash paid for capital expenditures at the other states segment during 2017, compared with 2016, was primarily driven by upgrades to MERC's natural gas distribution systems and mains as well as the construction of an office building due to the relocation of MERC's headquarters during 2017.

The decrease in cash paid for capital expenditures at the non-utility energy infrastructure segment during 2017, compared with 2016, was primarily driven by reduced construction activity for We Power's fuel flexibility project at the Oak Creek Expansion units, which was completed during December 2017.

The increase in cash paid for capital expenditures at the corporate and other segment during 2017, compared with 2016, was primarily driven by a project to implement a new enterprise resource planning system and various other software projects.

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Financing Activities

2018 Compared with 2017

Net cash provided by financing activities decreased $135.0 million during 2018, compared with 2017, driven by:

- A $798.8 million decrease in cash related to higher repayments of long-term debt during 2018, compared with 2017.
- A $588.9 million net decrease in cash due to $4.5 million of net repayments of commercial paper during 2018, compared with $584.4 million of net borrowings of commercial paper during 2017.
- A $40.8 million decrease in cash due to higher dividends paid on our common stock during 2018, compared with 2017. In January 2018, our Board of Directors increased our quarterly dividend by $0.0325 per share (6.25%) effective with the first quarter of 2018 dividend payment.

These decreases in net cash provided by financing activities were partially offset by a $1,305.0 million increase in cash due to the issuance of more long-term debt during 2018, compared with 2017.

2017 Compared with 2016

Net cash related to financing activities increased $1,007.1 million during 2017, compared with 2016, driven by:

- An $819.2 million net increase in cash due to $584.4 million of net borrowings of commercial paper during 2017, compared with $234.8 million of net repayments of commercial paper during 2016.
- A $151.5 million increase in cash related to lower repayments of long-term debt during 2017, compared with 2016. In February 2016, we repurchased a portion of Integrys's 2006 Junior Notes at a discount.
- A $36.7 million increase in cash due to fewer shares of our common stock purchased during 2017, compared with 2016, to satisfy requirements of our stock-based compensation plans.
- A $35.0 million increase in cash due to the issuance of more long-term debt during 2017, compared with 2016.

These increases in net cash related to financing activities were partially offset by a $31.6 million decrease in cash related to higher dividends paid on our common stock during 2017, compared with 2016. In January 2017, our Board of Directors increased our quarterly dividend by $0.025 per share effective with the first quarter of 2017 dividend payment.

Significant Financing Activities

For more information on our financing activities, see Note 12, Short-Term Debt and Lines of Credit, and Note 13, Long-Term Debt and Capital Lease Obligations.

Capital Resources and Requirements

Capital Resources

Liquidity

We anticipate meeting our capital requirements for our existing operations through internally generated funds and short-term borrowings, supplemented by the issuance of intermediate or long-term debt securities, depending on market conditions and other factors.

We currently have access to the capital markets and have been able to generate funds internally and externally to meet our capital requirements. Our ability to attract the necessary financial capital at reasonable terms is critical to our overall strategic plan. We currently believe that we have adequate capacity to fund our operations for the foreseeable future through our existing borrowing arrangements, access to capital markets, and internally generated cash.

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WEC Energy Group, WE, WG, WPS, 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. See Note 12, Short-Term Debt and Lines of Credit, for more information about these credit facilities.

The following table shows our capitalization structure as of December 31, 2018 and 2017, as well as an adjusted capitalization structure that we believe is consistent with how a majority of the rating agencies currently view our 2007 Junior Notes:

	2018		2017	
(in millions)	Actual	Adjusted	Actual	Adjusted
Common equity	$9,788.9	$10,038.9	$9,461.4	$9,711.4
Preferred stock of subsidiary	30.4	30.4	30.4	30.4
Long-term debt (including current portion)	10,359.0	10,109.0	9,588.7	9,338.7
Short-term debt	1,440.1	1,440.1	1,444.6	1,444.6
Total capitalization	$21,618.4	$21,618.4	$20,525.1	$20,525.1
Total debt	$11,799.1	$11,549.1	$11,033.3	$10,783.3
Ratio of debt to total capitalization	54.6 %	53.4 %	53.8 %	52.5 %

Included in long-term debt on our balance sheets as of December 31, 2018 and 2017, is $500.0 million principal amount of 2007 Junior Notes. The adjusted presentation attributes $250.0 million of the 2007 Junior Notes to common equity and $250.0 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 by certain rating agencies' treatment of the 2007 Junior Notes. 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.

For a summary of the interest rate, maturity, and amount outstanding of each series of our long-term debt on a consolidated basis, see our capitalization statements.

As described in Note 10, Common Equity, certain restrictions exist on the ability of our subsidiaries to transfer funds to us. We do not expect these restrictions to have any material effect on our operations or ability to meet our cash obligations.

At December 31, 2018, we were in compliance with all 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 12, Short-Term Debt and Lines of Credit, for more information about our credit facilities and other short-term credit agreements. See Note 13, Long-Term Debt and Capital Lease Obligations, for more information about our long-term debt.

Working Capital

As of December 31, 2018, our current liabilities exceeded our current assets by $1,084.1 million. We do not expect this to have any impact on our liquidity since we believe we have adequate back-up lines of credit in place for our ongoing operations. We also believe that we can access the capital markets to finance our construction programs and to refinance current maturities of long-term debt, if necessary.

Credit Rating Risk

We do not have any credit agreements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. However, we have certain agreements in the form of commodity contracts and employee benefit plans that could require collateral or a termination payment in the event of a credit rating change to below BBB- at S&P Global Ratings and/or Baa3 at Moody's Investors Service. 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.

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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 January 2018, Moody's downgraded the rating outlook for WG to negative from stable as a result of the new Tax Legislation. The change in rating outlook has not had, and we do not believe that it will have, a material impact on our ability to access capital markets.

In July 2018, Moody's downgraded the ratings of WEC Energy Group (senior unsecured), WECC (senior unsecured), and Integrys (senior unsecured) to Baa1 from A3. Moody's also downgraded the ratings of WEC Energy Group (junior subordinated) and Integrys (junior subordinated) to Baa2 from Baa1. Reduced cash flow due to Tax Legislation, which impacted the majority of companies in our industry, was a catalyst for the downgrade. Moody's affirmed the commercial paper ratings of WEC Energy Group (senior unsecured, P-2), and Integrys (senior unsecured, P-2) and changed the rating outlook for WEC Energy Group, WECC, and Integrys, to stable from rating under review.

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.

If we are unable to successfully take actions to manage any additional adverse impacts of the Tax Legislation, or if additional interpretations, regulations, amendments or technical corrections exacerbate the adverse impacts of the Tax Legislation, the legislation could result in credit rating agencies placing our or our subsidiaries’ credit ratings on negative outlook or additional downgrading of our or our subsidiaries' credit ratings. Any such actions by credit rating agencies may make it more difficult and costly for us and our subsidiaries to issue future debt securities and certain other types of financing and could increase borrowing costs under our and our subsidiaries’ credit facilities.

Capital Requirements

Contractual Obligations

We have the following contractual obligations and other commercial commitments as of December 31, 2018:

	Payments Due by Period [1]				
(in millions)	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt obligations [2]	$19,244.9	$810.8	$2,854.8	$820.0	$14,759.3
Capital lease obligations [3]	56.7	15.5	33.6	7.6	—
Operating lease obligations [4]	86.9	8.7	15.5	14.0	48.7
Energy and transportation purchase obligations [5]	12,002.8	1,211.9	1,926.7	1,755.2	7,109.0
Purchase orders [6]	834.2	411.3	260.4	85.6	76.9
Pension and OPEB funding obligations [7]	69.7	12.6	57.1	—	—
Total contractual obligations	$32,295.2	$2,470.8	$5,148.1	$2,682.4	$21,993.9

(1) The amounts included in the table are calculated using current market prices, forward curves, and other estimates.

(2) Principal and interest payments on long-term debt (excluding capital lease obligations). The interest due on our variable rate debt is based on the interest rates that were in effect on December 31, 2018.

(3) Capital lease obligations for power purchase commitments. This amount does not include We Power leases to WE which are eliminated upon consolidation.

(4) Operating lease obligations for office space, land, and rail car leases.

(5) Energy and transportation purchase obligations under various contracts for the procurement of fuel, power, gas supply, and associated transportation related to utility and non-utility operations.

(6) Purchase obligations related to normal business operations, information technology, and other services.

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(7) Obligations for pension and OPEB plans cannot reasonably be estimated beyond 2021.

The table above does not include liabilities related to the accounting treatment for uncertainty in income taxes because we are not able to make a reasonably reliable estimate as to the amount and period of related future payments at this time. For additional information regarding these liabilities, refer to Note 14, Income Taxes.

The table above also does not reflect estimated future payments related to the manufactured gas plant remediation liability of $616.4 million at December 31, 2018, as the amount and timing of payments are uncertain. We expect to incur costs annually to remediate these sites. See Note 22, Commitments and Contingencies, for more information about environmental liabilities.

AROs in the amount of $461.4 million are not included in the above table. Settlement of these liabilities cannot be determined with certainty, but we believe the majority of these liabilities will be settled in more than five years. See Note 8, Asset Retirement Obligations, for more information.

Obligations for utility operations have historically been included as part of the rate-making process and therefore are generally recoverable from customers.

Capital Expenditures and Significant Capital Projects

We have several capital projects that will require significant capital expenditures over the next three years and beyond. All projected capital requirements are subject to periodic review and may vary significantly from estimates, depending on a number of factors. These factors include environmental requirements, regulatory restraints and requirements, impacts from the Tax Legislation, additional changes in tax laws and regulations, acquisition and development opportunities, market volatility, and economic trends. Our estimated capital expenditures and acquisitions for the next three years are as follows:

(in millions)	2019	2020	2021
Wisconsin	$1,344.9	$1,677.5	$1,559.1
Illinois	765.2	684.0	602.4
Other states	155.4	135.8	105.5
Non-utility energy infrastructure	424.2	418.8	242.8
Corporate and other	15.7	11.0	1.1
Total	$2,705.4	$2,927.1	$2,510.9

WPS is continuing work on the SMRP. This project includes modernizing parts of its electric distribution system, including burying or upgrading lines. The project focuses on constructing facilities to improve the reliability of electric service WPS provides to its customers. WPS expects to invest approximately $185 million between 2019 and 2022 on this project. WE, WPS, and WG will also continue to upgrade their electric and natural gas distribution systems to enhance reliability. These upgrades include the advanced metering infrastructure (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.

As part of our commitment to invest in zero-carbon generation, we plan to invest in utility scale solar of up to 350 MW within our Wisconsin segment. WPS has partnered with an unaffiliated utility to acquire ownership interests in two proposed solar projects in Wisconsin. Badger Hollow Solar Farm will be located in Iowa County, Wisconsin, and Two Creeks Solar Project will be located in Manitowoc County, Wisconsin. WPS will own 100 MW of the output of each project for a total of 200 MW. WPS's share of the cost of both projects is estimated to be $260 million. Subject to the receipt of PSCW approval, commercial operation for both projects is targeted for the end of 2020. Solar generation technology has greatly improved, has become more cost-effective, and it complements our summer demand curve.

In connection with the formation of UMERC, we entered into an agreement with Tilden under which it will purchase electric power from UMERC for 20 years, contingent upon UMERC's construction of approximately 180 MW of natural gas-fired generation in the Upper Peninsula of Michigan. The new generation is expected to begin commercial operation during the second quarter of 2019. The estimated cost of this project is approximately $266 million ($277 million with AFUDC), 50% of which is expected to be recovered from Tilden, with the remaining 50% expected to be recovered from UMERC's other utility customers.

PGL is continuing work on the SMP, a project under which PGL is replacing approximately 2,000 miles of Chicago's aging natural gas pipeline infrastructure. PGL currently recovers these costs through a surcharge on customer bills pursuant to an ICC approved QIP rider, which is in effect through 2023. PGL's projected average annual investment through 2021 is between $280 million and $300 million. See Note 24, Regulatory Environment, for more information on the SMP.

The non-utility energy infrastructure segment includes our investments in Bishop Hill III, Coyote Ridge, and Upstream. See Note 2, Acquisitions, for more information on these wind projects.

We expect to provide capital contributions to ATC and ATC Holdco (not included in the above table) of approximately $185 million from 2019 through 2021.

Common Stock Matters

For information related to our common stock matters, see Note 10, Common Equity.

On January 17, 2019, our Board of Directors increased our quarterly dividend to $0.59 per share effective with the first quarter of 2019 dividend payment, which equates to an annual dividend of $2.36 per share. In addition, the Board of Directors affirmed our dividend policy that continues to target a dividend payout ratio of 65-70% of earnings.

Investments in Outside Trusts

We use outside trusts to fund our pension and certain OPEB obligations. These trusts had investments of approximately $3.5 billion as of December 31, 2018. These trusts hold investments that are subject to the volatility of the stock market and interest rates. We contributed $77.6 million, $120.5 million, and $28.7 million to our pension and OPEB plans in 2018, 2017, and 2016, respectively. Future contributions to the plans will be dependent upon many factors, including the performance of existing plan assets and long-term discount rates. For additional information, see Note 18, Employee Benefits.

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 12, Short-Term Debt and Lines of Credit, Note 17, Guarantees, and Note 21, Variable Interest Entities.

FACTORS AFFECTING RESULTS, LIQUIDITY, AND CAPITAL RESOURCES

Market Risks and Other Significant Risks

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

Regulatory Recovery

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

Regulated entities are allowed to defer certain costs that would otherwise be charged to expense if the regulated entity believes the recovery of those costs is probable. We record regulatory assets pursuant to specific orders or by a generic order 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. In general, our regulatory assets are recovered over a period of between one to six years. 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. As of December 31, 2018, our regulatory assets were $3,855.8 million, and our regulatory liabilities were $4,288.4 million.

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Due to the Tax Legislation signed into law in December 2017, our regulated utilities remeasured their deferred taxes and recorded a tax benefit of $2,450 million. Our utilities have been returning this tax benefit to ratepayers through refunds, bill credits, riders, and reductions to other regulatory assets, which we expect to continue. See Note 14, Income Taxes, and Note 24, Regulatory Environment, for more information.

We expect to request or have requested recovery of the costs related to the following projects discussed in recent or pending rate proceedings, orders, and investigations involving our utilities:

- In June 2016, the PSCW approved the deferral of costs related to WPS's ReACT™ project above the originally authorized $275.0 million level through 2017. The total cost of the ReACT™ project, excluding $51 million of AFUDC, was $342 million. In September 2017, the PSCW approved an extension of this deferral through 2019 as part of a settlement agreement. See Note 24, Regulatory Environment, for more information. WPS will be required to obtain a separate approval for collection of these deferred costs in a future rate case.

- Prior to its acquisition by us, Integrys initiated an information technology project with the goal of improving the customer experience at its subsidiaries. Specifically, the project is expected to provide functional and technological benefits to the billing, call center, and credit collection functions. As of December 31, 2018, we had not received any significant disallowances of the costs incurred for this project. We will be required to obtain approval for the recovery of additional costs incurred through the completion of this long-term project.

- 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 is subject to an annual reconciliation whereby costs are reviewed for accuracy and prudency. In March 2018, PGL filed its 2017 reconciliation with the ICC, which, along with the 2016 and 2015 reconciliations, are still pending. In 2018, PGL agreed to a settlement of the 2014 reconciliation, which included a rate base reduction of $5.4 million and a $4.7 million refund to ratepayers. As of December 31, 2018, there can be no assurance that all costs incurred under the QIP rider during the open reconciliation years will be deemed recoverable by the ICC.

See Note 24, Regulatory Environment, for more information regarding recent and pending rate proceedings, orders, and investigations involving our utilities.

Commodity Costs

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

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

Higher commodity costs can increase our working capital requirements, result in higher gross receipts taxes, and lead to increased energy efficiency investments by our customers to reduce utility usage and/or fuel substitution. Higher commodity costs combined with slower economic conditions also expose us to greater risks of accounts receivable write-offs as more customers are unable to pay their bills. See Note 1(d), Operating Revenues, for more information on riders and other mechanisms that allow for cost recovery or refund of uncollectible expense.

Weather

Our utilities' rates are based upon estimated normal temperatures. Our electric utility margins are unfavorably sensitive to below normal temperatures during the summer cooling season and, to some extent, to above normal temperatures during the winter heating season. Our natural gas utility margins are unfavorably sensitive to above normal temperatures during the winter heating season. PGL, NSG, and MERC have decoupling mechanisms in place that help reduce the impacts of weather. Decoupling mechanisms differ by state and allow utilities to recover or refund certain differences between actual and authorized margins. A summary of actual weather information in our utilities' service territories during 2018, 2017, and 2016, as measured by degree days, may be found in Results of Operations.

Interest Rates

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

Based on the variable rate debt outstanding at December 31, 2018, and December 31, 2017, a hypothetical increase in market interest rates of one percentage point would have increased annual interest expense by $16.9 million and $20.6 million in 2018 and 2017, respectively. This sensitivity analysis was performed assuming a constant level of variable rate debt during the period and an immediate increase in interest rates, with no other changes for the remainder of the period.

Marketable Securities Return

We use various trusts to fund our pension and OPEB obligations. These trusts invest in debt and equity securities. Changes in the market prices of these assets can affect future pension and OPEB expenses. Additionally, future contributions can also be affected by the investment returns on trust fund assets. We believe that the financial risks associated with investment returns would be partially mitigated through future rate actions by our various utility regulators.

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

(in millions)	As of December 31, 2018	Expected Return on Assets in 2019
Pension trust funds	$ 2,690.8	7.12 %
OPEB trust funds	$ 771.7	7.25 %

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

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

Economic Conditions

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

Inflation

We continue to monitor the impact of inflation, especially with respect to the costs of medical plans, fuel, transmission access, construction costs, and regulatory and environmental compliance in order to minimize its effects in future years through pricing strategies, productivity improvements, and cost reductions. We do not believe the impact of general inflation will have a material impact on our future results of operations.

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

Competitive Markets

Electric Utility Industry

The regulated energy industry continues to experience significant changes. The FERC continues to support large RTOs, which affects the structure of the wholesale market. To this end, MISO implemented the MISO Energy Markets, including the use of LMP to value electric transmission congestion and losses. Increased competition in the retail and wholesale markets, which may result from restructuring efforts, could have a significant and adverse financial impact on us. It is uncertain when, if at all, retail choice might be implemented in Wisconsin. However, Michigan has adopted a limited retail choice program.

Wisconsin

Electric utility revenues in Wisconsin are regulated by the PSCW. The PSCW continues to maintain the position that the question of whether to implement electric retail competition in Wisconsin should ultimately be decided by the Wisconsin legislature. No such legislation has been introduced in Wisconsin to date.

Michigan

Under Michigan law, our retail customers may choose an alternative electric supplier to provide power supply service. As a result, some of our small retail customers have switched to an alternative electric supplier. At December 31, 2018, Michigan law limited customer choice to 10% of an electric utility's Michigan retail load, but this cap could potentially be reduced in future years due to the December 2016 passage of Michigan Act 341. Based on current law, our iron ore mine customer, Tilden, is exempt from the 10% cap. In addition, certain load increases by facilities already using an alternative electric supplier can still be serviced by their alternative electric supplier, when various conditions exist, even if the cap has already been met. When a customer switches to an alternative electric supplier, we continue to provide distribution and customer service functions for the customer.

Natural Gas Utility Industry

We offer natural gas transportation services to our customers that elect to purchase natural gas from an alternative retail natural gas supplier. Since these transportation customers continue to use our distribution systems to transport natural gas to their facilities, we earn distribution revenues from them. As such, there is little impact on our net income from customers purchasing natural gas from an alternative retail natural gas supplier as natural gas costs are passed through to customers in rates on a one-for-one basis.

Wisconsin

The PSCW previously instituted generic proceedings to consider how its regulation of natural gas distribution utilities should change to reflect a competitive environment in the natural gas industry. To date, the PSCW has made a policy decision to provide customer classes with competitive markets the option to choose an alternative retail natural gas supplier. The PSCW has also adopted standards for transactions between a utility and its natural gas marketing affiliates. All of our Wisconsin customer classes have competitive market choices and, therefore, can purchase natural gas directly from either an alternative retail natural gas supplier or their local natural gas utility. We are currently unable to predict the impact of potential future industry restructuring on our results of operations or financial position.

Illinois

Since 2002, PGL and NSG have provided their customers with the option to choose an alternative retail natural gas supplier. We are not required by the ICC or state law to make this option available to customers, but since this option is currently provided to our Illinois customers, we would need ICC approval to eliminate it.

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Minnesota

MERC has provided its commercial and industrial customers with the option to choose an alternative retail natural gas supplier since 2006. We are not required by the MPUC or state law to make this option available to customers, but since this option is currently provided to our Minnesota commercial and industrial customers, we would need MPUC approval to eliminate it.

Michigan

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

Environmental Matters

See Note 22, 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.

Other Matters

Tax Cuts and Jobs Act of 2017

In December 2017, the Tax Legislation was signed into law. The PSCW and the MPSC have issued written orders regarding how to refund certain tax savings from the Tax Legislation to ratepayers in Wisconsin and Michigan, respectively, and the ICC has approved the VITA in Illinois. In Minnesota, the MPUC addressed the various impacts of the Tax Legislation in MERC's 2018 rate case. We are also working with the FERC to modify our formula rate tariffs for the impacts of the Tax Legislation, and we expect to receive FERC approval for the modified tariffs in 2019. See Note 24, Regulatory Environment, for more information.

American Transmission Company Allowed Return on Equity Complaints

In November 2013, a group of MISO industrial customer organizations filed a complaint with the FERC requesting to reduce the base ROE used by MISO transmission owners, including ATC, from 12.2% to 9.15%. In October 2014, the FERC issued an order to hear the complaint on ROE and set a refund effective date retroactive to November 2013. In December 2015, the ALJ issued an initial decision recommending that ATC and all other MISO transmission owners be authorized to collect a base ROE of 10.32%, as well as the 0.5% incentive adder approved by the FERC in January 2015 for MISO transmission owners. The incentive adder only applies to revenues collected after January 6, 2015. In September 2016, the FERC issued an order related to this complaint affirming the use of the ROE stated in the ALJ's initial decision, effective as of the order date, on a going-forward basis. The order also required ATC to provide refunds, with interest, for the 15-month refund period from November 12, 2013, through February 11, 2015. The $28.3 million refund that ATC provided to WE and WPS for transmission costs paid during the refund period reduced the regulatory assets recorded under the PSCW-approved escrow accounting for transmission expense and resulted in a net regulatory liability for WPS.

In February 2015, a second complaint was filed with the FERC requesting a reduction in the base ROE used by MISO transmission owners, including ATC, to 8.67%, with a refund effective date retroactive to February 12, 2015. In June 2016, the ALJ issued an initial decision recommending that ATC and all other MISO transmission owners be authorized to collect a base ROE of 9.7%, as well as the 0.5% incentive adder approved for MISO transmission owners. The ALJ's initial decision is not binding on the FERC and applies to revenues collected from February 12, 2015, through May 11, 2016. We are uncertain when a FERC order related to this matter will be issued.

The MISO transmission owners have filed various appeals related to several of the FERC orders with the D.C. Circuit Court of Appeals as well as requests for rehearing.

In November 2018, the FERC issued an order directing MISO transmission owners, including ATC, to submit briefs on a proposed change to the methodology used to calculate their base ROE. If the proposed methodology is approved, ATC's base ROE for the period from November 12, 2013 through February 11, 2015 would be 10.28% instead of the 10.32% approved by the FERC in September 2016. The proposed methodology would also impact the second complaint filed in February 2015 and ATC's base ROE going forward. We are uncertain when a final FERC order related to the proposed methodology will be issued.

Bonus Depreciation Provisions

Bonus depreciation is an additional amount of first-year tax deductible depreciation that is awarded above what would normally be available. The bonus depreciation deduction available for public utility property subject to rate-making by a government entity or public utility commission was modified by the Tax Legislation signed into law on December 22, 2017. Based on the provisions of the Tax Legislation, bonus depreciation can no longer be deducted for public utility property acquired and placed in service after December 31, 2017. The provisions of the Tax Legislation regarding the repeal of bonus depreciation do not apply to some of our non-utility investments.

Critical Accounting Policies and Estimates

Preparation of financial statements and related disclosures in compliance with GAAP requires the application of appropriate technical accounting rules and guidance as well as the use of estimates. The application of these policies necessarily involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges, and anticipated recovery of costs. These judgments, in and of themselves, could materially impact the financial statements and disclosures based on varying assumptions. In addition, the financial and operating environment may also have a significant effect, not only on the operation of our business, but on our results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies applied have not changed.

The following is a list of accounting policies that are most significant to the portrayal of our financial condition and results of operations and that require management's most difficult, subjective, or complex judgments.

Goodwill

We completed our annual goodwill impairment tests for all of our reporting units that carried a goodwill balance as of July 1, 2018. No impairments were recorded as a result of these tests. For all of our reporting units, the fair values calculated in step one of the test were greater than their carrying values. The fair values for the reporting units were calculated using a combination of the income approach and the market approach.

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

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

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

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

For all of our reporting units, fair value exceeded carrying value by over 50%. Based on these results, our reporting units are not at risk of failing step one of the goodwill impairment test.

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Our reporting units had the following goodwill balances at July 1, 2018:

(in millions, except percentages)	Goodwill	Percentage of Total Goodwill	
Wisconsin	$2,104.3	68.9	%
Illinois	758.7	24.9	%
Other states	183.2	6.0	%
Bluewater	6.6	0.2	%
Total goodwill	$3,052.8	100.0	%

See Note 9, Goodwill, for more information.

Long-Lived Assets

In accordance with ASC 360, Property, Plant, and Equipment, we periodically assess the recoverability of certain long-lived assets when events or changes in circumstances indicate that the carrying amount of those long-lived assets may not be recoverable. Examples of events or changes in circumstances include, but are not limited to, a significant decrease in the market price, a significant change in use, adverse legal factors or a change in business climate, operating or cash flow losses, or an expectation that the asset might be sold. These assessments require significant assumptions and judgments by management. The long-lived assets assessed for impairment generally include certain assets within regulated operations that may not be fully recovered from our customers as a result of regulatory decisions that will be made in the future, and assets within nonregulated operations that are proposed to be sold or are currently generating operating losses.

We have evaluated future plans for our older and less efficient fossil fuel generating units and have either retired or announced the retirement of certain generating units. In accordance with ASC 980-360, Regulated Operations – Property, Plant, and Equipment, when it becomes probable that a generating unit will be retired before the end of its useful life, we assess whether the generating unit meets the criteria for abandonment accounting. Generating units that are considered probable of abandonment are expected to cease operations in the near term, significantly before the end of their original estimated useful lives. As a result, the remaining net book value of these assets can be significant. If a generating unit meets applicable criteria to be considered probable of abandonment, and the unit has been abandoned, we assess the likelihood of recovery of the remaining carrying value of that generating unit at the end of each reporting period. If it becomes probable that regulators will disallow full recovery as well as a return on the remaining net book value of a generating unit that is either abandoned or probable of being abandoned, an impairment loss may be required. An impairment loss would be recorded if the remaining carrying value of the generating unit is greater than the present value of the amount expected to be recovered from ratepayers.

Pleasant Prairie power plant, Pulliam Units 7 and 8, and the jointly-owned Edgewater 4 generating unit were retired during 2018. PIPP continued to meet the criteria to be considered probable of abandonment as of December 31, 2018. We plan to ask for full cost recovery of and a full return on the remaining book value of these generating units and have concluded that no impairment was required related to these assets as of December 31, 2018. See Note 6, Property, Plant, and Equipment, for more information on our retired generating units, including various approvals we have received from the FERC.

Pension and Other Postretirement Employee Benefits

The costs of providing non-contributory defined pension benefits and OPEB, described in Note 18, Employee Benefits, are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

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

Pension and OPEB plan assets are primarily made up of equity and fixed income investments. Fluctuations in actual equity and fixed income market returns, as well as changes in general interest rates, may result in increased or decreased benefit costs in future periods. We believe that such changes in costs would be recovered or refunded at our utilities through the rate-making process.

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

Actuarial Assumption (in millions, except percentages)	Percentage-Point Change in Assumption	Impact on Projected Benefit Obligation	Impact on 2018 Pension Cost
Discount rate	(0.5)	$ 178.3	$ 19.9
Discount rate	0.5	(159.8)	(13.6)
Rate of return on plan assets	(0.5)	N/A	13.6
Rate of return on plan assets	0.5	N/A	(13.6)

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

Actuarial Assumption (in millions, except percentages)	Percentage-Point Change in Assumption	Impact on Postretirement Benefit Obligation	Impact on 2018 Postretirement Benefit Cost
Discount rate	(0.5)	$ 36.6	$ 2.8
Discount rate	0.5	(33.0)	(1.1)
Health care cost trend rate	(0.5)	(18.9)	(3.9)
Health care cost trend rate	0.5	21.7	4.5
Rate of return on plan assets	(0.5)	N/A	4.1
Rate of return on plan assets	0.5	N/A	(4.1)

The discount rates are selected based on hypothetical bond portfolios consisting of noncallable (or callable with make-whole provisions), noncollateralized, high-quality corporate bonds across the full maturity spectrum. The bonds are generally rated "Aa" with a minimum amount outstanding of $50.0 million. From the hypothetical bond portfolios, a single rate is determined that equates the market value of the bonds purchased to the discounted value of the plans' expected future benefit payments.

We establish our expected return on assets based on consideration of historical and projected asset class returns, as well as the target allocations of the benefit trust portfolios. The assumed long-term rate of return on pension plan assets was 7.12%, 7.11%, and 7.12%, in 2018, 2017, and 2016, respectively. The actual rate of return on pension plan assets, net of fees, was (4.30)%, 13.74%, and 7.75%, in 2018, 2017, and 2016, respectively.

In selecting assumed health care cost trend rates, past performance and forecasts of health care costs are considered. For more information on health care cost trend rates and a table showing future payments that we expect to make for our pension and OPEB, see Note 18, Employee Benefits.

Regulatory Accounting

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

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

The application of the Regulated Operations Topic of the FASB ASC would be discontinued if all or a separable portion of our utility operations no longer met the criteria for application. Our regulatory assets and liabilities would be written off to income as an unusual or infrequently occurring item in the period in which discontinuation occurred. As of December 31, 2018, we had

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$3,855.8 million in regulatory assets and $4,288.4 million in regulatory liabilities. See Note 5, Regulatory Assets and Liabilities, for more information.

Unbilled Revenues

We record utility operating revenues when energy is delivered to our customers. However, the determination of energy sales to individual customers is based upon the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of their last meter reading are estimated and corresponding unbilled revenues are calculated. This unbilled revenue is estimated each month based upon actual generation and throughput volumes, recorded sales, estimated customer usage by class, weather factors, estimated line losses, and applicable customer rates. Significant fluctuations in energy demand for the unbilled period or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. Total utility operating revenues during 2018 of approximately $7.6 billion included accrued utility revenues of $497.7 million as of December 31, 2018.

Income Tax Expense

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

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

Significant management judgment is required in determining our provision for income taxes, deferred income tax assets and liabilities, the liability for unrecognized tax benefits, and any valuation allowance recorded against deferred income tax assets. The assumptions involved are supported by historical data, reasonable projections, and interpretations of applicable tax laws and regulations across multiple taxing jurisdictions. Significant changes in these assumptions could have a material impact on our financial condition and results of operations. See Note 1(m), Income Taxes, and Note 14, Income Taxes, for a discussion of accounting for income taxes.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity, and Capital Resources – Market Risks and Other Significant Risks, as well as Note 1(n), Fair Value Measurements,
Note 1(o), Derivative Instruments, and Note 17, Guarantees, for information concerning potential market risks to which we are exposed.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

A. REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets and statements of capitalization of WEC Energy Group, Inc. and subsidiaries (the "Company") as of December 31, 2018 and 2017, the related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2018, and the related notes and the schedules listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2019, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

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

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

/s/DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
February 26, 2019

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

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A. REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of WEC Energy Group, Inc. and subsidiaries (the " Company") as of December 31, 2018, based on the criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control – Integrated Framework (2013) issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2018, of the Company and our report dated February 26, 2019. expressed an unqualified opinion on those consolidated financial statements and financial statement schedules.

Basis for Opinion

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

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
February 26, 2019

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B. CONSOLIDATED INCOME STATEMENTS

Year Ended December 31			
(in millions, except per share amounts)	2018	2017	2016
Operating revenues	$7,679.5	$7,648.5	$7,472.3
Operating expenses			
Cost of sales	2,897.9	2,822.8	2,647.4
Other operation and maintenance	2,270.5	2,056.1	2,171.3
Depreciation and amortization	845.8	798.6	762.6
Property and revenue taxes	196.9	194.9	194.7
Total operating expenses	6,211.1	5,872.4	5,776.0
Operating income	1,468.4	1,776.1	1,696.3
Equity in earnings of transmission affiliates	136.7	154.3	146.5
Other income, net	70.3	73.7	66.6
Interest expense	445.1	415.7	402.7
Other expense	(238.1)	(187.7)	(189.6)
Income before income taxes	1,230.3	1,588.4	1,506.7
Income tax expense	169.8	383.5	566.5
Net income	1,060.5	1,204.9	940.2
Preferred stock dividends of subsidiary	1.2	1.2	1.2
Net income attributed to common shareholders	$1,059.3	$1,203.7	$939.0
Earnings per share			
Basic	$3.36	$3.81	$2.98
Diluted	$3.34	$3.79	$2.96
Weighted average common shares outstanding			
Basic	315.5	315.6	315.6
Diluted	316.9	317.2	316.9

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

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C. CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31 (in millions)	2018	2017	2016
Net income	$1,060.5	$1,204.9	$940.2
Other comprehensive (loss) income, net of tax			
Derivatives accounted for as cash flow hedges			
Net derivative losses, net of tax	(2.1)	—	—
Reclassification of net gains to net income, net of tax	(1.2)	(1.3)	(1.3)
Cumulative effect adjustment from adoption of ASU 2018-02	1.6	—	—
Cash flow hedges, net	(1.7)	(1.3)	(1.3)
Defined benefit plans			
Pension and OPEB adjustments arising during the period, net of tax of $(1.2), $0.6, and $0.1, respectively	(3.1)	0.9	(0.8)
Amortization of pension and OPEB costs included in net periodic benefit cost, net of tax	0.3	0.4	0.4
Cumulative effect adjustment from adoption of ASU 2018-02	(1.0)	—	—
Defined benefit plans, net	(3.8)	1.3	(0.4)
Other comprehensive loss, net of tax	(5.5)	—	(1.7)
Comprehensive income	1,055.0	1,204.9	938.5
Preferred stock dividends of subsidiary	1.2	1.2	1.2
Comprehensive income attributed to common shareholders	$1,053.8	$1,203.7	$937.3

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

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D. CONSOLIDATED BALANCE SHEETS

At December 31 (in millions, except share and per share amounts)	2018	2017
Assets		
Current assets		
Cash and cash equivalents	$84.5	$38.9
Accounts receivable and unbilled revenues, net of reserves of $149.2 and $143.2, respectively	1,280.9	1,350.7
Materials, supplies, and inventories	548.2	539.0
Prepayments	256.8	210.0
Other	77.2	74.9
Current assets	2,247.6	2,213.5
Long-term assets		
Property, plant, and equipment, net of accumulated depreciation of $8,515.9 and $8,618.5, respectively	22,000.9	21,347.0
Regulatory assets	3,805.1	2,803.2
Equity investment in transmission affiliates	1,665.3	1,553.4
Goodwill	3,052.8	3,053.5
Other	704.1	619.9
Long-term assets	31,228.2	29,377.0
Total assets	$33,475.8	$31,590.5
Liabilities and Equity		
Current liabilities		
Short-term debt	$1,440.1	$1,444.6
Current portion of long-term debt	365.0	842.1
Accounts payable	876.4	859.9
Accrued payroll and benefits	185.4	169.1
Other	464.8	553.6
Current liabilities	3,331.7	3,869.3
Long-term liabilities		
Long-term debt	9,994.0	8,746.6
Deferred income taxes	3,388.1	2,999.8
Deferred revenue, net	520.4	543.3
Regulatory liabilities	4,251.6	3,718.6
Environmental remediation liabilities	616.4	617.4
Pension and OPEB obligations	422.8	397.4
Other	1,108.1	1,206.3
Long-term liabilities	20,301.4	18,229.4
Commitments and contingencies (Note 22)		
Common shareholders' equity		
Common stock – $0.01 par value; 325,000,000 shares authorized; 315,523,192 and 315,574,624 shares outstanding, respectively	3.2	3.2
Additional paid in capital	4,250.1	4,278.5
Retained earnings	5,538.2	5,176.8

Accumulated other comprehensive (loss) income	(2.6)	2.9
Common shareholders' equity	9,788.9	9,461.4
Preferred stock of subsidiary	30.4	30.4
Noncontrolling interests	23.4	—
Total liabilities and equity	$33,475.8	$31,590.5

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

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E. CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31 (in millions)	2018	2017	2016
Operating activities			
Net income	$1,060.5	$1,204.9	$940.2
Reconciliation to cash provided by operating activities			
Depreciation and amortization	845.8	798.6	762.6
Deferred income taxes and investment tax credits, net	297.3	271.7	493.8
Contributions and payments related to pension and OPEB plans	(77.6)	(120.5)	(28.7)
Equity income in transmission affiliates, net of distributions	(18.6)	(4.8)	(46.6)
Change in –			
Accounts receivable and unbilled revenues	23.5	(86.4)	(180.7)
Materials, supplies, and inventories	(8.8)	49.3	100.0
Other current assets	(10.0)	(7.1)	103.2
Accounts payable	110.6	8.5	34.4
Other current liabilities	(67.6)	161.8	(20.8)
Other, net	290.4	(197.4)	(53.6)
Net cash provided by operating activities	2,445.5	2,078.6	2,103.8
Investing activities			
Capital expenditures	(2,115.7)	(1,959.5)	(1,423.7)
Acquisition of Bishop Hill III, net of restricted cash acquired of $4.5	(162.9)	—	—
Acquisition of Forward Wind Energy Center	(77.1)	—	—
Acquisition of Coyote Ridge	(61.4)	—	—
Acquisition of Bluewater	—	(226.0)	—
Capital contributions to transmission affiliates	(53.5)	(109.6)	(42.3)
Proceeds from the sale of assets and businesses	12.1	24.0	166.3
Proceeds from the sale of investments held in rabbi trust	118.6	8.7	1.7
Purchase of investments held in rabbi trust	(65.0)	(3.7)	(59.2)
Other, net	20.5	12.0	3.0
Net cash used in investing activities	(2,384.4)	(2,254.1)	(1,354.2)
Financing activities			
Exercise of stock options	29.1	30.8	41.6
Purchase of common stock	(72.4)	(71.3)	(108.0)
Dividends paid on common stock	(697.3)	(656.5)	(624.9)
Issuance of long-term debt	1,740.0	435.0	400.0
Retirement of long-term debt	(953.3)	(154.5)	(306.0)
Change in short-term debt	(4.5)	584.4	(234.8)
Other, net	(15.2)	(6.5)	(13.6)
Net cash provided by (used in) financing activities	26.4	161.4	(845.7)
Net change in cash, cash equivalents, and restricted cash	87.5	(14.1)	(96.1)
Cash, cash equivalents, and restricted cash at beginning of year	58.6	72.7	168.8
Cash, cash equivalents, and restricted cash at end of year	$146.1	$58.6	$72.7

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

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F. CONSOLIDATED STATEMENTS OF EQUITY

	WEC Energy Group Common Shareholders' Equity							
(in millions, expect per share amounts)	Common Stock	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Shareholders' Equity	Preferred Stock of Subsidiary	Non-controlling Interests	Total Equity
Balance at December 31, 2015	$3.2	$4,347.2	$4,299.8	$ 4.6	$ 8,654.8	$ 30.4	$ —	$8,685.2
Net income attributed to common shareholders	—	—	939.0	—	939.0	—	—	939.0
Other comprehensive loss	—	—	—	(1.7)	(1.7)	—	—	(1.7)
Common stock dividends of $1.98 per share	—	—	(624.9)	—	(624.9)	—	—	(624.9)
Exercise of stock options	—	41.6	—	—	41.6	—	—	41.6
Purchase of common stock	—	(108.0)	—	—	(108.0)	—	—	(108.0)
Stock-based compensation and other	—	29.0	—	—	29.0	—	—	29.0
Balance at December 31, 2016	$3.2	$4,309.8	$4,613.9	$ 2.9	$ 8,929.8	$ 30.4	$ —	$8,960.2
Net income attributed to common shareholders	—	—	1,203.7	—	1,203.7	—	—	1,203.7
Common stock dividends of $2.08 per share	—	—	(656.5)	—	(656.5)	—	—	(656.5)
Exercise of stock options	—	30.8	—	—	30.8	—	—	30.8
Purchase of common stock	—	(71.3)	—	—	(71.3)	—	—	(71.3)
Cumulative effect adjustment from ASU 2016-09 adoption	—	—	15.7	—	15.7	—	—	15.7
Stock-based compensation and other	—	9.2	—	—	9.2	—	—	9.2
Balance at December 31, 2017	$3.2	$4,278.5	$5,176.8	$ 2.9	$ 9,461.4	$ 30.4	$ —	$9,491.8
Net income attributed to common shareholders	—	—	1,059.3	—	1,059.3	—	—	1,059.3
Other comprehensive loss	—	—	—	(6.1)	(6.1)	—	—	(6.1)
Common stock dividends of $2.21 per share	—	—	(697.3)	—	(697.3)	—	—	(697.3)
Exercise of stock options	—	29.1	—	—	29.1	—	—	29.1
Purchase of common stock	—	(72.4)	—	—	(72.4)	—	—	(72.4)
Cumulative effect adjustment from ASU 2018-02 adoption	—	—	(0.6)	0.6	—	—	—	—
Acquisition of noncontrolling interests	—	—	—	—	—	—	23.8	23.8
Stock-based compensation and other	—	14.9	—	—	14.9	—	(0.4)	14.5
Balance at December 31, 2018	$3.2	$4,250.1	$5,538.2	$ (2.6)	$ 9,788.9	$ 30.4	$ 23.4	$9,842.7

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

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G. CONSOLIDATED STATEMENTS OF CAPITALIZATION

At December 31 (in millions)			2018	2017
Common shareholder's equity (see accompanying statement)			$9,788.9	$9,461.4
Preferred stock of subsidiary (Note 11)			30.4	30.4
Long-term debt	Interest Rate	Year Due		
WEC Energy Group Senior Notes (unsecured)	1.65%	2018	—	300.0
	2.45%	2020	400.0	400.0
	3.375%	2021	600.0	—
	3.55%	2025	500.0	500.0
	6.20%	2033	200.0	200.0
WEC Energy Group Junior Notes (unsecured) [(1)]	4.853%	2067	500.0	500.0
WE Debentures (unsecured)	1.70%	2018	—	250.0
	4.25%	2019	250.0	250.0
	2.95%	2021	300.0	300.0
	3.10%	2025	250.0	250.0
	6.50%	2028	150.0	150.0
	5.625%	2033	335.0	335.0
	5.70%	2036	300.0	300.0
	3.65%	2042	250.0	250.0
	4.25%	2044	250.0	250.0
	4.30%	2045	250.0	250.0
	4.30%	2048	300.0	—
	6.875%	2095	100.0	100.0
WPS Senior Notes (unsecured)	1.65%	2018	—	250.0
	3.35%	2021	400.0	—
	6.08%	2028	50.0	50.0
	5.55%	2036	125.0	125.0
	3.671%	2042	300.0	300.0
	4.752%	2044	450.0	450.0
WG Debentures (unsecured)	3.53%	2025	200.0	200.0
	5.90%	2035	90.0	90.0
	3.71%	2046	200.0	200.0
PGL First and Refunding Mortgage Bonds (secured) [(2)]	8.00%	2018	—	5.0
	4.63%	2019	75.0	75.0
	3.87%	2028	150.0	—
	3.90%	2030	50.0	50.0
	1.875%	2033	50.0	50.0
	4.00%	2033	50.0	50.0
	3.98%	2042	100.0	100.0
	3.96%	2043	220.0	220.0
	4.21%	2044	200.0	200.0
	3.65%	2046	50.0	50.0
	3.65%	2046	150.0	150.0
	3.77%	2047	100.0	100.0
NSG First Mortgage Bonds (secured) [(3)]	3.43%	2027	28.0	28.0
	3.87%	2028	50.0	—
	3.96%	2043	54.0	54.0

MGU Senior Notes (unsecured)	3.11%	2027	30.0	30.0
	3.41%	2032	30.0	30.0
	4.01%	2047	30.0	30.0
MERC Senior Notes (unsecured)	3.11%	2027	40.0	40.0
	3.41%	2032	40.0	40.0
	4.01%	2047	40.0	40.0
Bluewater Gas Storage Senior Notes (unsecured)	3.76%	2019-2047	122.7	125.0

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Long-term debt (continued)	Interest Rate		Year Due	2018	2017
We Power Subsidiaries Notes (secured, nonrecourse)	4.91%	(4)	2019-2030	95.1	101.0
	5.209%	(5)	2019-2030	182.7	194.1
	4.673%	(5)	2019-2031	153.5	162.4
	6.00%	(4)	2019-2033	116.6	121.5
	6.09%	(5)	2030-2040	275.0	275.0
	5.848%	(5)	2031-2041	215.0	215.0
WECC Notes (unsecured)	6.94%		2028	50.0	50.0
Integrys Senior Notes (unsecured)	4.17%		2020	250.0	250.0
Integrys Junior Notes (unsecured)	3.60%		2066	—	114.9
	6.00%		2073	400.0	400.0
ATC Holding Senior Notes (unsecured)	4.18%		2025	85.0	—
	4.37%		2028	56.5	—
	4.47%		2030	98.5	—
Obligations under capital leases				23.3	27.0
Total				10,410.9	9,627.9
Integrys acquisition fair value adjustment				20.6	26.9
Unamortized debt issuance costs				(44.7)	(38.0)
Unamortized discount, net and other				(27.8)	(28.1)
Total long-term debt, including current portion				10,359.0	9,588.7
Current portion of long-term debt and capital lease obligations				(365.0)	(842.1)
Total long-term debt				9,994.0	8,746.6
Total long-term capitalization				$19,813.3	$18,238.4

(1) Variable interest rate reset quarterly. The rate was 4.73% as of December 31, 2018. On July 12, 2018 we executed two interest rate swaps that provided a fixed rate of 4.9765% on $250.0 million of the outstanding notes. The effective rate of 4.853% is a blended rate of of the variable and fixed portions. The rate was 3.53% as of December 31, 2017 and, prior to May 15, 2017, the fixed rate was 6.25%.

(2) PGL's First Mortgage Bonds are subject to the terms and conditions of PGL's First Mortgage Indenture dated January 2, 1926, as supplemented. Under the terms of the Indenture, substantially all property owned by PGL is pledged as collateral for these outstanding debt securities.

PGL has used certain First Mortgage Bonds to secure tax exempt interest rates. The Illinois Finance Authority has issued Tax Exempt Bonds, and the proceeds from the sale of these bonds were loaned to PGL. In return, PGL issued equal principal amounts of certain collateralized First Mortgage Bonds.

(3) NSG's First Mortgage Bonds are subject to the terms and conditions of NSG's First Mortgage Indenture dated April 1, 1955, as supplemented. Under the terms of the Indenture, substantially all property owned by NSG is pledged as collateral for these outstanding debt securities.

(4) We Power senior notes, secured by a collateral assignment of the leases between PWGS and WE related to PWGS 1 and PWGS 2.

(5) We Power senior notes, secured by a collateral assignment of the leases between Elm Road Generating Station Supercritical, LLC and WE related to ER 1 and ER 2.

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

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H. NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Nature of Operations—WEC Energy Group serves approximately 1.6 million electric customers and 2.9 million natural gas customers, and it owns approximately 60% of ATC.

As used in these notes, the term "financial statements" refers to the consolidated financial statements. This includes the income statements, statements of comprehensive income, balance sheets, statements of cash flows, statements of equity, and statements of capitalization, unless otherwise noted. On our financial statements, we consolidate our majority-owned subsidiaries and reflect noncontrolling interests for the portion of entities that we do not own as a component of consolidated equity separate from the equity attributable to our shareholders. The noncontrolling interests that we reported as equity on our balance sheet as of December 31, 2018 related to the minority interests at Bishop Hill III and Coyote Ridge held by third parties.

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

- Wisconsin segment – Consists of WE, WG, and WPS, which are engaged primarily in the generation of electricity and the distribution of electricity and natural gas in Wisconsin, and UMERC, which includes WE's former electric operations and WPS's former electric and natural gas operations in the state of Michigan that were transferred to UMERC effective January 1, 2017.

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

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

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

- Non-utility energy infrastructure segment – Consists of We Power, which is principally engaged in the ownership of electric power generating facilities for long-term lease to WE, and Bluewater, which owns underground natural gas storage facilities in Michigan. Our 90% membership interest in Bishop Hill III, a wind generating facility located in Henry County, Illinois, and our 80% membership interest in Coyote Ridge, a wind generating facility under construction in Brookings County, South Dakota, are also included in this segment. See Note 2, Acquisitions, for more information on Coyote Ridge, Bishop Hill III, and Bluewater.

- Corporate and other segment – Consists of the WEC Energy Group holding company, the Integrys holding company, the PELLC holding company, Wispark, Bostco, Wisvest, WECC, WBS, PDL, and ITF. In the first quarter of 2017, we sold substantially all of the remaining assets of Bostco, and, in October 2018, Bostco was dissolved. In the second quarter of 2016, we sold certain assets of Wisvest, which no longer has significant operations, and, in the first quarter of 2016, the sale of ITF was completed. See Note 3, Dispositions, for more information on these sales.

Our financial statements also reflect our proportionate interests in certain jointly owned utility facilities. See Note 7, Jointly Owned Utility Facilities, for more information. Investments in companies not controlled by us, but over which we have significant influence regarding the operating and financial policies of the investee, are accounted for using the equity method.

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

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

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(d) Operating Revenues—The following discussion includes our significant accounting policies related to operating revenues, including our adoption of ASU 2014-09, Revenues from Contracts with Customers. For additional required disclosures on disaggregation of operating revenues as required by this ASU, see Note 4, Operating Revenues.

Adoption of ASU 2014-09, Revenues from Contracts with Customers

On January 1, 2018, we adopted ASU 2014-09, Revenues from Contracts with Customers, and the related amendments. In accordance with the guidance, we recognize revenues when control of the promised goods or services is transferred to our customers in an amount that reflects the consideration we expect to be entitled to receive in exchange for those goods or services. These revenues include unbilled revenues, which are estimated using the amount of energy delivered to our customers but not billed until after the end of the period.

We adopted this standard using the modified retrospective method. Results for reporting periods beginning after January 1, 2018, are presented under the new standard. The comparative information has not been restated and continues to be reported under the accounting standards in effect for those periods. Adoption of the standard did not result in an adjustment to our opening retained earnings balance as of January 1, 2018, and we do not expect the adoption of the standard to have a material impact on our net income in future periods.

We adopted the following practical expedients and optional exemptions for the implementation of this standard:

- We elected to exclude from the transaction price any amounts collected from customers for all sales taxes and other similar taxes.
- When applicable, we elected to apply the standard to a portfolio of contracts with similar characteristics, primarily our tariff-based contracts, as we reasonably expect that the effects on the financial statements of applying this guidance to the portfolio would not differ materially from applying this guidance to the individual contracts.
- We elected to recognize revenue in the amount we have the right to invoice for performance obligations satisfied over time when the consideration received from a customer corresponds directly with the value provided to the customer during the same period.
- We elected to not disclose the remaining performance obligations of a contract that has an original expected duration of one year or less.
- We elected to apply this standard only to contracts that are not completed as of the date of initial application.

Revenues from Contracts with Customers

Electric Utility Operating Revenues

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

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

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

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

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

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

Natural Gas Utility Operating Revenues

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

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

The tariffs of our natural gas utilities include various rate mechanisms that allow them to recover or refund changes in prudently incurred costs from rate case-approved amounts. The rates for all of our natural gas utilities include one-for-one recovery mechanisms for natural gas commodity costs. We defer any difference between actual natural gas costs incurred and costs recovered through rates as a current asset or liability. The deferred balance is returned to or recovered from customers at intervals throughout the year. In addition, the rates of PGL and NSG, and the residential tariffs of WE and WG, include riders or other mechanisms for cost recovery or refund of uncollectible expense based on the difference between actual uncollectible write-offs and the amounts recovered in rates. The rates of PGL and NSG include riders for cost recovery of both environmental cleanup costs, energy conservation and management program costs, and income tax expense changes resulting from the Tax Legislation. Finally, PGL's rates include a cost recovery mechanism for SMP costs.

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

Other Non-Utility Operating Revenues

As part of the construction of the We Power electric generating units, we capitalized interest during construction, which is included in property, plant, and equipment. As allowed by the PSCW, we collected these carrying costs from WE's utility customers during construction. The equity portion of these carrying costs was recorded as deferred revenue, and we continually amortize the deferred carrying costs to revenues over the life of the related lease term that We Power has with WE. During the twelve months ended December 31, 2018, we recorded $25.3 million of revenue related to these deferred carrying costs, which were included in the contract liability balance at the beginning of the period. This contract liability is presented as deferred revenue, net on our balance sheets.

Non-utility operating revenues are also derived from servicing appliances for customers at MERC. These contracts customarily have a duration of one year or less and consist of a single performance obligation satisfied over time. We use a time-based output method to recognize revenues monthly for the service fee.

Revenues from distributed renewable solar projects consist primarily of sales of renewable energy and solar renewable energy certificates (SRECs) generated by PDL. The sale of SRECs is a distinct performance obligation as they are often sold separately from the renewable energy generated. Although the performance obligation for the sale of renewable energy is recognized over time and the performance obligation for SRECs is recognized at a point-in-time, the timing of revenue recognition is the same, as the generation of renewable energy and sales of SREC's occur concurrently.

On August 31, 2018, we completed the acquisition of an 80% membership interest in a commercially operational 132 MW wind generating facility located in Henry County, Illinois, known as Bishop Hill III. In December 2018, we completed the purchase of an additional 10% membership interest in Bishop Hill III. See Note 2, Acquisitions, for more information on this acquisition. Bishop Hill III has a 22-year offtake agreement with an unaffiliated company for the sale of all energy produced by the facility. The contract consists of one distinct performance obligation satisfied over time, as the electricity is delivered and consumed by the customer simultaneously. We recognize revenue as energy is produced and delivered to the customer within the production month.

Other Operating Revenues

Alternative Revenues

Alternative revenues are created from programs authorized by regulators that allow our utilities to record additional revenues by adjusting rates in the future, usually as a surcharge applied to future billings, in response to past activities or completed events. Alternative revenue programs allow compensation for the effects of weather abnormalities, other external factors, or demand side management initiatives. Alternative revenue programs can also provide incentive awards if the utility achieves certain objectives and in other limited circumstances. We record alternative revenues when the regulator-specified conditions for recognition have been met. We reverse these alternative revenues as the customer is billed, at which time this revenue is presented as revenues from contracts with customers.

Below is a summary of the alternative revenue programs at our utilities:

- The rates of PGL, NSG, and MERC include decoupling mechanisms. These mechanisms differ by state and allow the utilities to recover or refund the differences between actual and authorized margins for certain customer classes. See Note 24, Regulatory Environment, for more information.
- MERC's rates include a conservation improvement program rider, which includes a financial incentive for meeting energy savings goals.
- WE and WPS provide wholesale electric service to customers under market-based rates and FERC formula rates. The customer is charged a base rate each year based upon a formula using prior year actual costs and customer demand. A true-up is calculated based on the difference between the amount billed to customers for the demand component of their rates and what the actual

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cost of service was for the year. The true-up can result in an amount that we will recover from or refund to the customer. We consider the true-up portion of the wholesale electric revenues to be alternative revenues.

(e) Materials, Supplies, and Inventories—Our inventory as of December 31 consisted of:

(in millions)	2018	2017
Natural gas in storage	$232.9	$209.0
Materials and supplies	226.6	211.2
Fossil fuel	88.7	118.8
Total	$548.2	$539.0

PGL and NSG price natural gas storage injections at the calendar year average of the costs of natural gas supply purchased. Withdrawals from storage are priced on the LIFO cost method. Inventories stated on a LIFO basis represented approximately 16% and 15% of total inventories at December 31, 2018 and 2017, respectively. The estimated replacement cost of natural gas in inventory at December 31, 2018 and 2017, exceeded the LIFO cost by $72.4 million and $152.1 million, respectively. In calculating these replacement amounts, PGL and NSG used a Chicago city-gate natural gas price per Dth of $3.08 at December 31, 2018, and $4.68 at December 31, 2017.

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

(f) Regulatory Assets and Liabilities—The economic effects of regulation can result in regulated companies recording costs and revenues that have been or are expected to be allowed in the rate-making process in a period different from the period in which the costs or revenues would be recognized by a nonregulated company. When this occurs, regulatory assets and regulatory liabilities are recorded on the balance sheet. Regulatory assets represent probable future revenues associated with certain costs or liabilities that have been deferred and are expected to be recovered through rates charged to customers. Regulatory liabilities represent amounts that are expected to be refunded to customers in future rates or amounts that are collected in rates for future costs.

Recovery or refund of regulatory assets and liabilities is based on specific periods determined by the regulators or occurs over the normal operating period of the assets and liabilities to which they relate. If at any reporting date a previously recorded regulatory asset is no longer probable of recovery, the regulatory asset is reduced to the amount considered probable of recovery with the reduction charged to expense in the reporting period the determination is made. See Note 5, Regulatory Assets and Liabilities, for more information.

(g) Property, Plant, and Equipment—We record property, plant, and equipment at cost. Cost includes material, labor, overhead, and both debt and equity components of AFUDC. Additions to and significant replacements of property are charged to property, plant, and equipment at cost; minor items are charged to other operation and maintenance expense. The cost of depreciable utility property less salvage value is charged to accumulated depreciation when property is retired.

We record straight-line depreciation expense over the estimated useful life of utility property using depreciation rates approved by the applicable regulators. Annual utility composite depreciation rates are shown below:

Annual Utility Composite Depreciation Rates	2018	2017	2016
WE	3.18%	2.95%	3.00%
WPS	2.50%	2.55%	2.58%
WG	2.30%	2.30%	2.34%
UMERC [1]	2.50%	2.46%	N/A
PGL	3.25%	3.29%	3.31%
NSG	2.45%	2.43%	2.44%

MERC [2]	1.95%	2.51%	2.53%
MGU	2.61%	2.61%	2.63%

[1] UMERC became operational effective January 1, 2017. See Note 1(a), Nature of Operations, for more information.

[2] The 2018 rate reflects the impact of a new depreciation study approved by the MPUC in May 2018. The rates approved were effective retroactive to January 2017. An approximate $1.4 million reduction in depreciation expense was recorded in 2018 related to this depreciation study.

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We depreciate our We Power assets over the estimated useful life of the various property components. The components have useful lives of between 10 to 45 years for PWGS 1 and PWGS 2 and 10 to 55 years for ER 1 and ER 2.

We capitalize certain costs related to software developed or obtained for internal use and record these costs to amortization expense over the estimated useful life of the related software, which ranges from 3 to 15 years. If software is retired prior to being fully amortized, the difference is recorded as a loss on the income statement.

Third parties reimburse the utilities for all or a portion of expenditures for certain capital projects. Such contributions in aid of construction costs are recorded as a reduction to property, plant, and equipment.

See Note 6, Property, Plant, and Equipment, for more information.

(h) Allowance for Funds Used During Construction—AFUDC is included in utility plant accounts and represents the cost of borrowed funds (AFUDC – Debt) used during plant construction, and a return on shareholders' capital (AFUDC – Equity) used for construction purposes. AFUDC – Debt is recorded as a reduction of interest expense, and AFUDC – Equity is recorded in other income, net.

The majority of AFUDC is recorded at WE, WPS, WBS, UMERC and WG. Approximately 50% of WE's, WPS's, WBS's, UMERC's, and WG's retail jurisdictional CWIP expenditures are subject to the AFUDC calculation. The AFUDC calculation for WBS uses the WPS AFUDC retail rate, while our other utilities' AFUDC rates are determined by their respective state commissions, each with specific requirements. Based on these requirements, the other utilities did not record significant AFUDC for 2018, 2017, or 2016. Average AFUDC rates are shown below:

	2018	
	Average AFUDC Retail Rate	Average AFUDC Wholesale Rate
WE	8.45%	3.63%
WPS	7.72%	1.96%
WBS	7.72%	N/A
WG	8.33%	N/A
UMERC	6.28%	N/A

Our regulated utilities and WBS recorded the following AFUDC for the years ended December 31:

(in millions)	2018	2017	2016
AFUDC – Debt			
WE	$1.5	$1.2	$1.7
WPS	1.9	1.6	8.1
WBS	0.2	1.1	0.3
WG	0.2	0.3	0.2
UMERC	2.4	0.1	N/A
Other	0.7	0.6	0.6
Total AFUDC – Debt	$6.9	$4.9	$10.9
AFUDC – Equity			
WE	$3.9	$3.1	$4.2
WPS	4.6	4.1	19.5
WBS	0.6	3.0	0.9
WG	0.6	0.9	0.5
UMERC	5.4	0.2	N/A

Other	0.1	0.1	—
Total AFUDC – Equity	$15.2	$11.4	$25.1

(i) Asset Impairment—Goodwill and other intangible assets with indefinite lives are subject to an annual impairment test. Interim impairment tests are performed when impairment indicators are present. Our reporting units containing goodwill perform annual goodwill impairment tests during the third quarter of each year. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit exceeds the reporting unit's fair value. An impairment loss is recorded for the excess of the carrying amount of the goodwill over its implied fair value. See Note 9, Goodwill, for more information. Intangible assets with definite lives are reviewed for impairment on a quarterly basis.

We periodically assess the recoverability of certain long-lived assets when factors indicate the carrying value of such assets may be impaired or such assets are planned to be sold. These assessments require significant assumptions and judgments by management. The long-lived assets assessed for impairment generally include certain assets within regulated operations that may not be fully recovered from our customers as a result of regulatory decisions that will be made in the future, as well as assets within nonregulated operations that are proposed to be sold or are currently generating operating losses. An impairment loss is recognized when the carrying amount of an asset is not recoverable and exceeds the fair value of the asset. The carrying amount of an asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. An impairment loss is measured as the excess of the carrying amount of the asset in comparison to the fair value of the asset.

When it becomes probable that a generating unit will be retired before the end of its useful life, we assess whether the generating unit meets the criteria for abandonment accounting. Generating units that are considered probable of abandonment are expected to cease operations in the near term, significantly before the end of their original estimated useful lives. If a generating unit meets the applicable criteria to be considered probable of abandonment, and the unit has been abandoned, we assess the likelihood of recovery of the remaining carrying value of that generating unit at the end of each reporting period. If it becomes probable that regulators will disallow full recovery as well as a return on the remaining net book value of a generating unit that is either abandoned or probable of being abandoned, an impairment loss may be required. An impairment loss would be recorded if the remaining carrying value of the generating unit is greater than the present value of the amount expected to be recovered from ratepayers. See Note 6, Property, Plant, and Equipment, for more information.

The carrying amounts of equity method investments are assessed for impairment by comparing the fair values of these investments to their carrying amounts if a fair value assessment was completed or by reviewing for the presence of impairment indicators. If an impairment exists, and it is determined to be other-than-temporary, an impairment loss is recognized equal to the amount by which the carrying amount exceeds the investment's fair value.

(j) Asset Retirement Obligations—We recognize, at fair value, legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development, and normal operation of the assets. An ARO liability is recorded, when incurred, for these obligations as long as the fair value can be reasonably estimated, even if the timing or method of settling the obligation is unknown. The associated retirement costs are capitalized as part of the related long-lived asset and are depreciated over the useful life of the asset. The ARO liabilities are accreted each period using the credit-adjusted risk-free interest rates associated with the expected settlement dates of the AROs. These rates are determined when the obligations are incurred. Subsequent changes resulting from revisions to the timing or the amount of the original estimate of undiscounted cash flows are recognized as an increase or a decrease to the carrying amount of the liability and the associated capitalized retirement costs. For our regulated entities, we recognize regulatory assets or liabilities for the timing differences between when we recover an ARO in rates and when we recognize the associated retirement costs. See Note 8, Asset Retirement Obligations, for more information.

(k) Stock-Based Compensation— In accordance with the shareholder approved Omnibus Stock Incentive Plan, we provide long-term incentives through our equity interests to our non-employee directors, officers, and other key employees. The plan provides for the granting of stock options, restricted stock, performance shares, and other stock-based awards. Awards may be paid in common stock, cash, or a combination thereof. The number of shares of common stock authorized for issuance under the plan is 34.3 million.

We recognize stock-based compensation expense on a straight-line basis over the requisite service period. Awards classified as equity awards are measured based on their grant-date fair value. Awards classified as liability awards are recorded at fair value each reporting period.

In March 2016, the FASB issued ASU 2016-09, Improvements to Employee Share-Based Payment Accounting, which modified certain aspects of the accounting for stock-based compensation awards. This ASU became effective for us on January 1, 2017. Under the new guidance, all excess tax benefits and tax deficiencies are recognized as income tax expense or benefit in the income statement on a prospective basis. Prior to January 1, 2017, these amounts were recorded in additional paid in capital on the balance sheet, and excess tax benefits could only be recognized to the extent they reduced taxes payable. In the first quarter of 2017, we recorded a $15.7 million cumulative-effect adjustment to increase retained earnings for excess tax benefits that had not been recognized in prior years as they did not reduce taxes payable.

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ASU 2016-09 also requires excess tax benefits to be classified as an operating activity on the statement of cash flows. As we elected to apply this provision on a prospective basis, the 2016 excess tax benefits continue to be reflected as a financing activity. As allowed under this ASU, we also elected to account for forfeitures as they occur, rather than estimating potential future forfeitures and recording them over the vesting period.

Stock Options

We grant non-qualified stock options that generally vest on a cliff-basis after a three-year period. The exercise price of a stock option under the plan cannot be less than 100% of our common stock's fair market value on the grant date. Historically, all stock options have been granted with an exercise price equal to the fair market value of our common stock on the date of the grant. Options may not be exercised within six months of the grant date except in the event of a change in control. Options expire no later than 10 years from the date of the grant.

Our stock options are classified as equity awards. The fair value of our stock options was calculated using a binomial option-pricing model. The following table shows the estimated weighted-average fair value per stock option granted along with the weighted-average assumptions used in the valuation models:

	2018	2017	2016
Stock options granted	710,710	552,215	794,764
Estimated weighted-average fair value per stock option	$7.71	$7.45	$5.14
Assumptions used to value the options:			
Risk-free interest rate	1.6% – 2.8%	0.7% – 2.5%	0.4% – 2.2%
Dividend yield	3.5 %	3.5 %	4.0 %
Expected volatility	18.0 %	19.0 %	18.1 %
Expected life (years)	5.9	6.8	6.1

The risk-free interest rate was based on the United States Treasury interest rate with a term consistent with the expected life of the stock options. The dividend yield was based on our dividend rate at the time of the grant and historical stock prices. Expected volatility and expected life assumptions were based on our historical experience.

Restricted Shares

Restricted shares granted to employees generally have a three-year vesting period with one-third of the award vesting on each anniversary of the grant date. This same vesting schedule is followed for restricted shares that were granted to non-employee directors prior to 2017. Restricted shares granted to certain officers and all non-employee directors after January 1, 2017, fully vest on the one-year anniversary of the grant date.

Our restricted shares are classified as equity awards.

Performance Units

Officers and other key employees are granted performance units under the WEC Energy Group Performance Unit Plan. Under the plan, the ultimate number of units that will be awarded is dependent on our total shareholder return (stock price appreciation plus dividends) as compared to the total shareholder return of a peer group of companies over a three-year period, and beginning in 2017, other performance metrics as determined by the Compensation Committee. Under the terms of the award, participants may earn between 0% and 175% of the performance unit award, as adjusted pursuant to the terms of the plan. Performance units also accrue forfeitable dividend equivalents in the form of additional performance units.

All grants of performance units are settled in cash and are accounted for as liability awards accordingly. The fair value of the performance units reflects our estimate of the final expected value of the awards, which is based on our stock price and performance achievement under the terms of the award. Stock-based compensation costs are recorded over the three-year performance period.

See Note 10, Common Equity, for more information on our stock-based compensation plans.

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(l) Earnings Per Share—We compute basic earnings per share by dividing our net income attributed to common shareholders by the weighted-average number of common shares outstanding during the period. Diluted earnings per share is computed in a similar manner, but includes the exercise and/or conversion of all potentially dilutive securities. Such dilutive securities include in-the-money stock options. The calculation of diluted earnings per share for the year ended December 31, 2016 excluded 181,709 stock options that had an anti-dilutive effect. There were no securities that had an anti-dilutive effect for the years ended December 31, 2018 and 2017.

(m) Income Taxes—We follow the liability method in accounting for income taxes. Accounting guidance for income taxes requires the recording of deferred assets and liabilities to recognize the expected future tax consequences of events that have been reflected in our financial statements or tax returns and the adjustment of deferred tax balances to reflect tax rate changes. We are required to assess the likelihood that our deferred tax assets would expire before being realized. If we conclude that certain deferred tax assets are likely to expire before being realized, a valuation allowance would be established against those assets. GAAP requires that, if we conclude in a future period that it is more likely than not that some or all of the deferred tax assets would be realized before expiration, we reverse the related valuation allowance in that period. Any change to the allowance, as a result of a change in judgment about the realization of deferred tax assets, is reported in income tax expense.

Investment tax credits associated with regulated operations are deferred and amortized over the life of the assets. Production tax credits are recognized in the period in which such credits are generated. The amount of the credit is based upon power production from our qualifying generation facilities. We file a consolidated Federal income tax return. Accordingly, we allocate Federal current tax expense benefits and credits to our subsidiaries based on their separate tax computations and our ability to monetize all credits on our consolidated Federal return. See Note 14, Income Taxes, for more information.

We recognize interest and penalties accrued, related to unrecognized tax benefits, in income tax expense in our income statements.

In February 2018, the FASB issued ASU 2018-02, Income Statement – Reporting Comprehensive Income. The amendments in this update allow entities to reclassify the income tax effects that are stranded in accumulated other comprehensive income as a result of the Tax Legislation to retained earnings. These amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2018, with early adoption permitted. We early adopted the amendments in the fourth quarter of 2018 and reclassified the stranded tax effects associated with the Tax Legislation from accumulated other comprehensive income to retained earnings. As of December 31, 2018, our accumulated other comprehensive income decreased $0.6 million as a result of adopting ASU 2018-02. The adoption of this guidance had no impact on our results of operations or cash flows.

(n) 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 derivative 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 are categorized in Level 3 due to the significance of unobservable or internally-developed inputs.

We recognize transfers between levels of the fair value hierarchy at their value as of the end of the reporting period.

See Note 15, Fair Value Measurements, for more information.

(o) Derivative Instruments—We use derivatives as part of our risk management program to manage the risks associated with the price volatility of interest rates, purchased power, generation, and natural gas costs for the benefit of our customers and shareholders. Our approach is non-speculative and designed to mitigate risk. Regulated hedging programs are approved by our state regulators.

We record derivative instruments on our balance sheets as assets or liabilities measured at fair value unless they qualify for the normal purchases and sales exception, and are so designated. We continually assess our contracts designated as normal and will discontinue the treatment of these contracts as normal if the required criteria are no longer met. Changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met or we receive regulatory treatment for the derivative. For most energy-related physical and financial contracts in our regulated operations that qualify as derivatives, our regulators allow the effects of fair value accounting to be offset to regulatory assets and liabilities.

We classify derivative assets and liabilities as current or long-term on our balance sheets based on the maturities of the underlying contracts. Cash flows from derivative activities are presented in the same category as the item being hedged within operating activities on our statements of cash flows.

Derivative accounting rules provide the option to present certain asset and liability derivative positions net on the balance sheets and to net the related cash collateral against these net derivative positions. We elected not to net these items. On our balance sheets, cash collateral provided to others is reflected in other current assets, and cash collateral received is reflected in other current liabilities. See Note 16, Derivative Instruments, for more information.

(p) Guarantees— We follow the guidance of the Guarantees Topic of the FASB ASC, which requires, under certain circumstances, that the guarantor recognize a liability for the fair value of the obligation undertaken in issuing the guarantee at its inception. See Note 17, Guarantees, for more information.

(q) Employee Benefits—The costs of pension and OPEB are expensed over the periods during which employees render service. These costs are distributed among our subsidiaries based on current employment status and actuarial calculations, as applicable. Our regulators allow recovery in rates for the utilities' net periodic benefit cost calculated under GAAP. See Note 18, Employee Benefits, for more information.

(r) Customer Deposits and Credit Balances—When utility customers apply for new service, they may be required to provide a deposit for the service. Customer deposits are recorded within other current liabilities on our balance sheets.

Utility customers can elect to be on a budget plan. Under this type of plan, a monthly installment amount is calculated based on estimated annual usage. During the year, the monthly installment amount is reviewed by comparing it to actual usage. If necessary, an adjustment is made to the monthly amount. Annually, the budget plan is reconciled to actual annual usage. Payments in excess of actual customer usage are recorded within other current liabilities on our balance sheets.

(s) Environmental Remediation Costs—We are subject to federal and state environmental laws and regulations that in the future may require us to pay for environmental remediation at sites where we have been, or may be, identified as a potentially responsible party. Loss contingencies may exist for the remediation of hazardous substances at various potential sites, including coal combustion product landfill sites and manufactured gas plant sites. See Note 8, Asset Retirement Obligations, for more information regarding coal combustion product landfill sites and Note 22, Commitments and Contingencies, for more information regarding manufactured gas plant sites.

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We record environmental remediation liabilities when site assessments indicate remediation is probable and we can reasonably estimate the loss or a range of losses. The estimate includes both our share of the liability and any additional amounts that will not be paid by other potentially responsible parties or the government. When possible, we estimate costs using site-specific information but also consider historical experience for costs incurred at similar sites. Remediation efforts for a particular site generally extend over a period of several years. During this period, the laws governing the remediation process may change, as well as site conditions, potentially affecting the cost of remediation.

Our utilities have received approval to defer certain environmental remediation costs, as well as estimated future costs, through a regulatory asset. The recovery of deferred costs is subject to the applicable state Commission's approval.

We review our estimated costs of remediation annually for our manufactured gas plant sites and coal combustion product landfill sites. We adjust the liabilities and related regulatory assets, as appropriate, to reflect the new cost estimates. Any material changes in cost estimates are adjusted throughout the year.

(t) Customer Concentrations of Credit Risk—We provide regulated electric service to customers in Wisconsin and Michigan and regulated natural gas service to customers in Wisconsin, Illinois, Minnesota, and Michigan. The geographic concentration of our customers did not contribute significantly to our overall exposure to credit risk. We periodically review customers' credit ratings, financial statements, and historical payment performance and require them to provide collateral or other security as needed. Credit risk exposure at WE, WG, PGL, and NSG is mitigated by their recovery mechanisms for uncollectible expense discussed in Note 1(d), Operating Revenues. As a result, we did not have any significant concentrations of credit risk at December 31, 2018. In addition, there were no customers that accounted for more than 10% of our revenues for the year ended December 31, 2018.

NOTE 2—ACQUISITIONS

On January 1, 2018, we adopted ASU 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business (ASU 2017-01). The amendments in this update clarify the definition of a business and provide guidance on evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. ASU 2017-01 also clarifies that transaction costs are capitalized in an asset acquisition but expensed in a business combination.

Acquisition of a Wind Generation Facility in South Dakota

In December 2018, we acquired an 80% ownership interest in Coyote Ridge, a 97.5 MW wind generating facility under construction in Brookings County, South Dakota, for $61.4 million, which includes transaction costs. This wind generating facility is expected to be in service by the end of 2019. The project has a 12-year offtake agreement with an unaffiliated third party for all of the energy produced. Under the Tax Legislation, our investment in Coyote Ridge is expected to qualify for production tax credits and 100% bonus depreciation. We are entitled to 99% of the tax benefits related to this facility. Coyote Ridge is included in the non-utility energy infrastructure segment.

The table below shows the allocation of the purchase price to the assets acquired at the date of the acquisition.

(in millions)	
Net property, plant, and equipment	$66.4
Noncontrolling interest	(5.0)
Total purchase price	$61.4

Acquisition of a Wind Generation Facility in Illinois

In August 2018, we completed the acquisition of an 80% membership interest in a commercially operational 132 MW wind generating facility located in Henry County, Illinois, known as Bishop Hill III, for $144.7 million, which includes transaction costs and is net of restricted cash acquired of $4.5 million. In December 2018, we completed the acquisition of an additional 10% membership interest in Bishop Hill III, for $18.2 million. Bishop Hill III has a 22-year offtake agreement with an unaffiliated company for the sale of all energy produced by the facility. Under the Tax Legislation, our investment in Bishop Hill III qualifies for production tax credits and