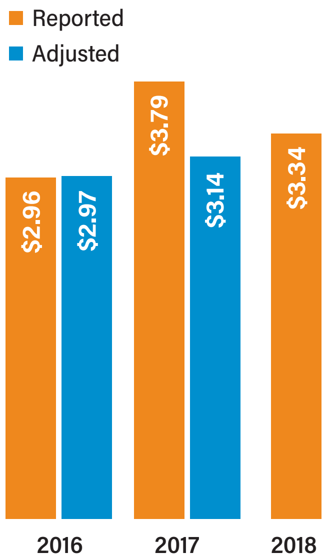
WEC Energy Group

Energized

2018 Annual Report

2018 FINANCIAL HIGHLIGHTS

Earnings per share[1]



1. Adjusted 2016 earnings per share exclude costs related to the acquisition of Integrys totaling 1 cent per share. Adjusted 2017 earnings per share exclude a one-time, non-cash gain of 65 cents per share related to the new tax law adopted in 2017.

Financial Snapshot

(In millions, except per share data and percentages)

	2018	2017	Change
GAAP earnings*	$1,059.3	$1,203.7	
GAAP earnings per share*	$3.34	$3.79	
Adjusted earnings*	$1,059.3	$997.0	6.2%
Adjusted earnings per share*	$3.34	$3.14	6.4%
Dividends per share	$2.21	$2.08	6.3%
Dividend yield	3.2%	3.1%	
Diluted average shares outstanding	316.9	317.2	
GAAP return on average common equity	11.01%	13.09%	
Adjusted return on average common equity*	11.01%	10.84%	
Book value per share	$31.02	$29.98	3.5%
Total assets	$33,476	$31,591	6.0%
Market price per share at year-end	$69.26	$66.43	4.3%
Market capitalization at year-end	$21,853	$20,964	4.2%

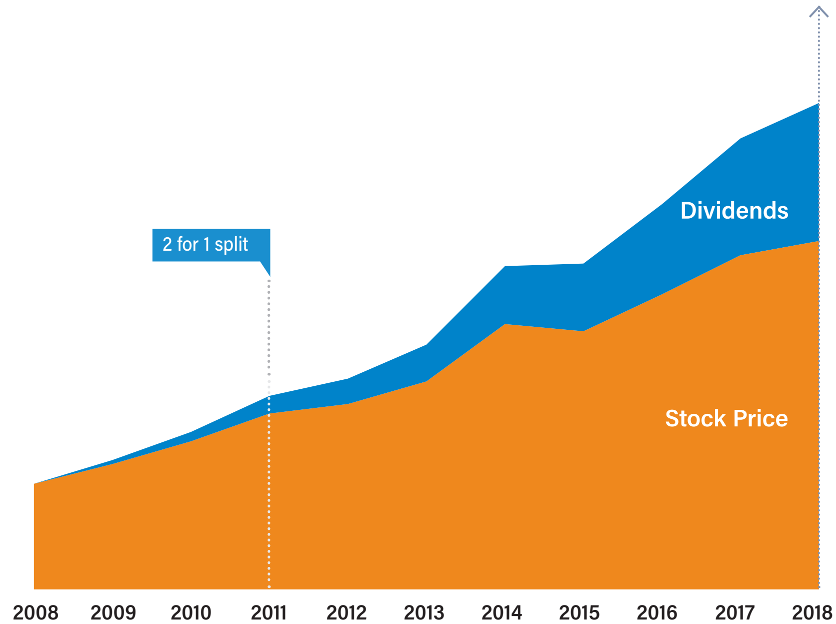
* There were no adjustments to GAAP earnings in 2018. Our 2017 adjusted results exclude $206.7 million ($0.65 per share) of tax benefits related to the new tax law adopted in 2017.

Dividends per share

Total Shareholder Return

WEC Energy Group consistently delivers among the best total returns in the industry. The illustration demonstrates our stock price appreciation plus the compound effect of dividend growth over the past decade.

A $100 investment in 2008 has grown to a total value of $461



Gale Klappa,
Executive Chairman

Kevin Fletcher,
President and
Chief Executive Officer

To our stockholders,

2018. A year of progress. A year of solid execution. A year of thoughtful change as we continue to build on our record of reliability, customer satisfaction, financial discipline and environmental stewardship.

Buoyed by a strong economy, we reported record net income from operations of $1.06 billion and earnings per share of $3.34 — exceeding our guidance for the year. Our credit ratings remain among the strongest in the industry. Our stock hit 11 new trading highs during the year. And our total shareholder return surpassed the performance of all the major market indexes.

We have always believed that financial success can only be sustained — year after year and decade after decade — by excelling at the fundamentals of our business.

We understand and appreciate the importance of predictable dividends and dividend growth. In January, our board of directors voted to raise the dividend again — for the 16th consecutive year — by 6.8 percent to an annual rate of $2.36 per share. Our goal is to pay out 65 to 70 percent of our earnings in dividends. We stand in the middle of that range today. So you can expect dividend growth to mirror the growth of our earnings going forward.

We have always believed that financial success can only be sustained — year after year and decade after decade — by excelling at the fundamentals of our business. We're pleased to report good news on that front as well.

For the eighth consecutive year, our largest subsidiary, We Energies, was named the most reliable utility in the Midwest. The award is presented each year by an independent consulting firm that analyzes the frequency and duration of customer outages. As you may know, we have made significant investments over the past decade to strengthen the reliability of our networks. We have rebuilt hundreds of miles of electric distribution lines and replaced thousands of poles and transformers. These investments are modernizing our delivery systems, reducing operating costs and improving energy efficiency.

From Chicago to the Upper Peninsula of Michigan, we have key infrastructure projects underway to meet customer needs for a safe, reliable supply of electricity and natural gas.

We also exceeded our customer satisfaction goals for 2018, and we achieved the best results in the nation in a J.D. Power study that surveyed electric utilities' largest business customers.

Of course, our day-to-day work to keep the lights on and energy flowing could not be done without the support of literally hundreds of qualified suppliers. Our supplier base today is more diverse than ever before. And we're pleased to report that our spending with women-, veteran- and minority-owned businesses set a new company record in 2018 — surpassing $263 million.

As we look forward, it's clear that improvements in technology are changing the way we think about our business — presenting us with a wider array of options to produce and deliver energy.

For example, the cost of utility-scale solar has dropped by approximately 70 percent in the past five years alone. With lower costs and greater efficiency, large-scale solar farms can now be a viable addition to our portfolio of energy-producing assets.

In Wisconsin, we hope to receive regulatory approval soon for the purchase of two solar farms in the state. Our Wisconsin Public Service subsidiary would own 100 megawatts at each site with an investment of $260 million. Madison Gas and Electric would own 50 megawatts at each site.

The solar installations would be among the largest in the Midwest.

We're also building new natural gas-fueled power plants in the Upper Peninsula of Michigan — plants that are modular and use reciprocating internal combustion engines to produce energy. We're on time and on budget for completion in the second quarter of this year. This creative approach will provide a cost-effective, long-term power supply for the region and allow us to retire our older coal-fueled power plant at Presque Isle. The bottom line: Our environmental performance will improve significantly, and we're projecting approximately $33 million of savings annually in operation and maintenance costs.

> We announced a new, aggressive goal — to reduce carbon emissions by 80 percent below 2005 levels by the year 2050.

As we continue to reshape our generating fleet, we expect to achieve our goal of reducing carbon dioxide emissions by 40 percent — well ahead of our 2030 target. And as we updated our long-range plan, we announced a new, aggressive goal — to reduce carbon emissions by 80 percent below 2005 levels by the year 2050.

We also made great strides in the past year on another segment of our business … the infrastructure segment. We agreed to acquire majority interests in three new wind farms: Upstream Wind Energy Center in Nebraska, Bishop Hill III Wind Energy Center in Illinois, and the Coyote Ridge Wind Farm in South Dakota. These renewable energy assets have long-term agreements to serve corporate and industry customers. For example, Coyote Ridge will provide carbon-free energy under contract to a subsidiary of Google.

Our investment in these infrastructure projects will total $587 million. We expect the returns on these investments to be higher than the returns we're earning in our traditional regulated business.

Finally, as you may know, the rigor we apply to succession planning took on even greater importance during 2018. Following a period of medical leave, Allen Leverett resigned from active duty with the company. Allen was named chief executive in 2016. He remains on our board of directors, and we're pleased that he will continue to bring his insight to our deliberations.

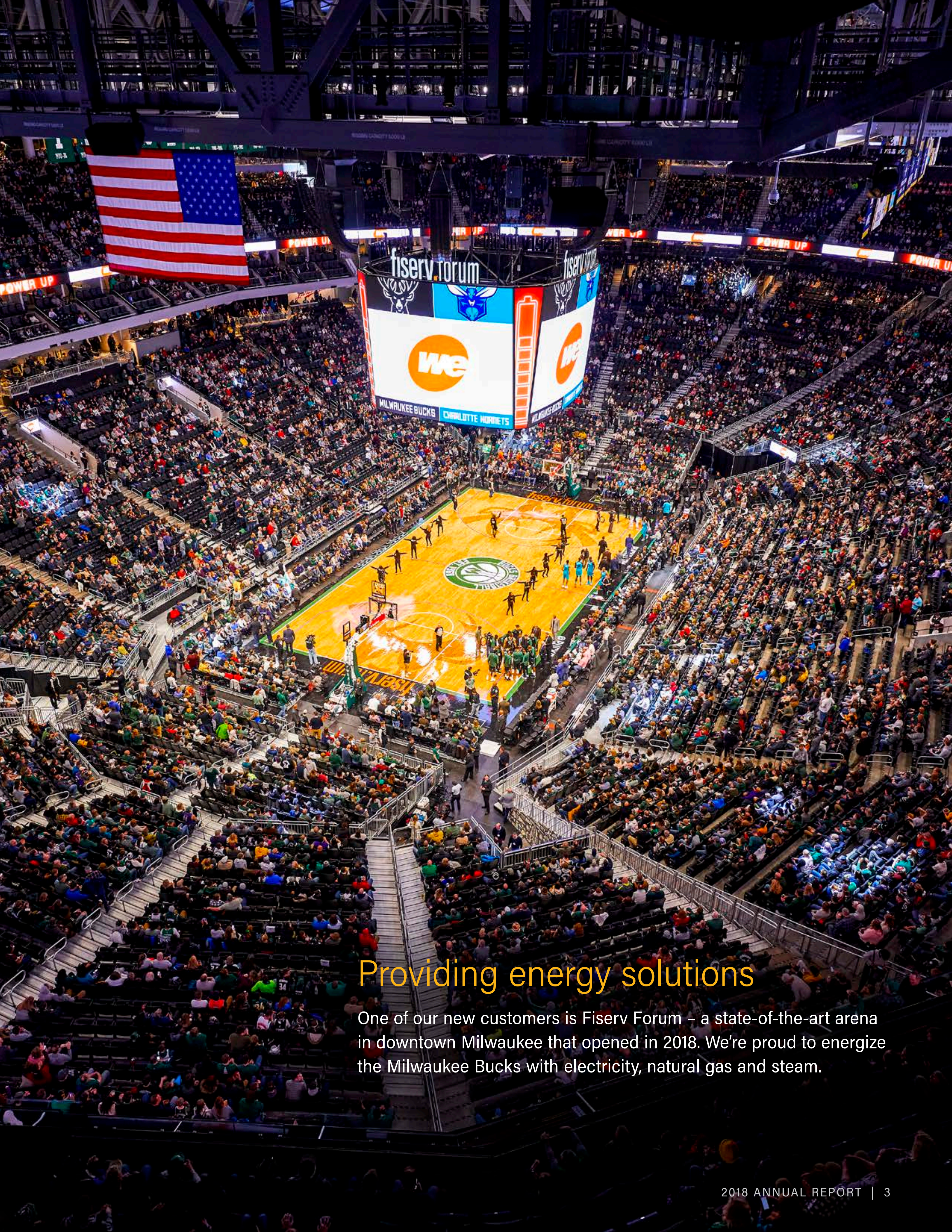
In light of Allen's decision, the board approved the creation of the Office of the Chair staffed by four industry veterans — Rick Kuester, Scott Lauber and the two of us. We've known each other and worked together for many years … so teamwork will come naturally as we write the next chapter of growth for this enduring franchise. And we'll continue to focus on developing the next generation of senior leadership.

As always, we appreciate your trust, your support and your investment in WEC Energy Group.

Sincerely,

Gale E. Klappa
Executive Chairman

J. Kevin Fletcher
President and Chief Executive Officer
Feb. 28, 2019



Providing energy solutions

One of our new customers is Fiserv Forum – a state-of-the-art arena in downtown Milwaukee that opened in 2018. We're proud to energize the Milwaukee Bucks with electricity, natural gas and steam.

Building new natural gas generation

One of our companies, Upper Michigan Energy Resources, is providing a reliable power supply for the Upper Peninsula. This new plant uses modular engines that run on natural gas – allowing for clean, efficient and flexible operations.

Investing in renewables

WEC Energy Group acquired a 90 percent interest in Bishop Hill III Wind Energy Center. Located in Henry County, Illinois, this wind farm will provide clean energy to one of our largest wholesale customers under a 22-year agreement.

An energy industry leader

WEC Energy Group is one of the nation's premier energy companies, with deep operational expertise, scale and financial resources to meet the Midwest region's electricity and natural gas needs.

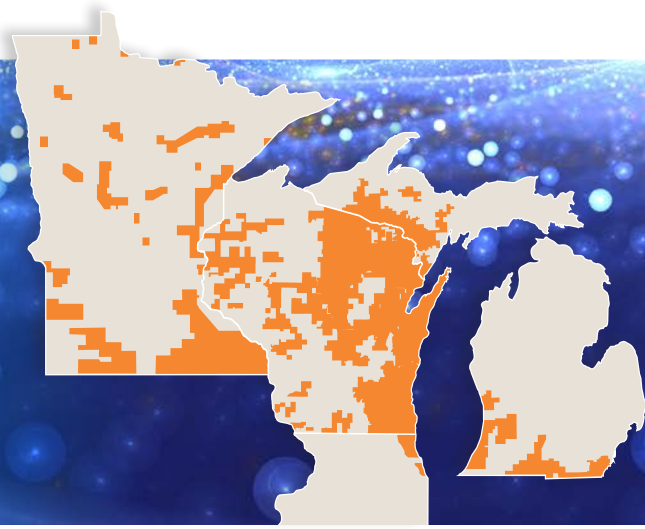
70,100 miles
of electric distribution

50,000 miles
of natural gas distribution and transmission lines
(including mains)

7,300 megawatts
of power capacity

8,000 employees

We provide vital services to more than **4.5 million** customers in Wisconsin, Illinois, Michigan and Minnesota.



WEC Energy Group includes the following companies:

We Energies delivers electricity, natural gas and steam to more than 2.2 million customers in Wisconsin.

Wisconsin Public Service delivers electricity and natural gas to more than 776,000 customers in northeast and central Wisconsin.

Michigan Gas Utilities delivers natural gas to more than 178,000 customers in southern and western Michigan.

Minnesota Energy Resources delivers natural gas to more than 238,000 customers in communities across Minnesota.

Peoples Gas delivers natural gas to more than 869,000 customers in the city of Chicago.

North Shore Gas delivers natural gas to more than 162,000 customers in Chicago's northern suburbs.

Upper Michigan Energy Resources delivers electricity and natural gas to more than 42,000 customers in Michigan's Upper Peninsula.

Bluewater Gas Storage, located in southeast Michigan, provides natural gas storage and hub services to We Energies and Wisconsin Public Service.

We Power designs, builds and owns modern, efficient power plants that are leased to We Energies.

WEC Infrastructure holds ownership interests in wind generating facilities that have long-term offtake agreements for the energy they produce.

WEC Energy Group

2018 ANNUAL FINANCIAL STATEMENTS AND REVIEW OF OPERATIONS

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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

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
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

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 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, 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.

BUSINESS OF THE COMPANY

WEC Energy Group, Inc. was incorporated in the state of Wisconsin in 1981 and became a diversified holding company in 1986. On June 29, 2015, Wisconsin Energy Corporation acquired 100% of the outstanding common shares of Integrys Energy Group and changed its name to WEC Energy Group, Inc. We maintain our principal executive offices in Milwaukee, Wisconsin.

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 our electric and natural gas utility companies, while the term "non-utility" refers to the activities of our electric and natural gas utility companies that are not regulated, as well as We Power and Bluewater. The term "nonregulated" refers to activities at Bishop Hill III, Coyote Ridge, and our Corporate and Other Segment.

Our wholly owned subsidiaries are primarily engaged in the business of providing regulated electricity service in Wisconsin and Michigan and regulated natural gas service in Wisconsin, Illinois, Michigan, and Minnesota. In addition, we have an approximate 60% equity interest in ATC, an electric transmission company operating primarily in four states. At December 31, 2018, we conducted our operations in the six reportable segments discussed below.

WISCONSIN SEGMENT

The Wisconsin segment includes the electric and natural gas utility and non-utility operations of WE, WG, WPS, and UMERC. UMERC became operational effective January 1, 2017, and holds the electric and natural gas distribution assets previously held by WE and WPS in the Upper Peninsula of Michigan.

At December 31, 2018, these companies served approximately 1,618,100 electric customers and 1,463,200 natural gas customers. This segment also includes steam service to approximately 400 WE steam customers in metropolitan Milwaukee, Wisconsin.

ILLINOIS SEGMENT

The Illinois segment includes the natural gas utility and non-utility operations of PGL and NSG. The approximately 1,032,800 natural gas customers served by PGL and NSG at December 31, 2018, were located in Chicago and the northern suburbs of Chicago. PGL also owns and operates a 38.8 billion-cubic-foot natural gas storage field in central Illinois.

OTHER STATES SEGMENT

The other states segment includes the natural gas utility and non-utility operations of MERC and MGU. These companies served approximately 416,100 natural gas customers at December 31, 2018, with MERC serving customers in various cities and communities throughout Minnesota, and MGU serving customers in southern and western Michigan.

ELECTRIC TRANSMISSION SEGMENT

The electric transmission segment includes our approximate 60% ownership interest in ATC, a for-profit, electric transmission company regulated by the FERC and certain state regulatory commissions. ATC owns, maintains, monitors, and operates electric transmission systems primarily in Wisconsin, Michigan, Illinois, and Minnesota.

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.

NON-UTILITY ENERGY INFRASTRUCTURE SEGMENT

The non-utility energy infrastructure segment includes the operations of We Power, Bluewater, our 90% membership interest in Bishop Hill III, and our 80% membership interest in Coyote Ridge. We Power, through wholly owned subsidiaries, owns and leases certain generating facilities to WE. PWGS 1 and PWGS 2, both natural gas-fired generating units, are being leased to WE under long-term leases that run for 25 years. ER 1 and ER 2, both coal-fired generating units, are being leased to WE under long-term leases that run for 30 years. Bluewater owns natural gas storage facilities in southeast Michigan and provides natural gas storage and hub services for the natural gas operations of WE, WG, and WPS.

Bishop Hill III is a wind generating facility located in Henry County, Illinois that has a 22-year offtake agreement with an unaffiliated company for the sale of all energy produced by the facility. Coyote Ridge is a wind generating facility under construction in Brookings County, South Dakota that is expected to be in service by the end of 2019. Coyote Ridge has a 12-year offtake agreement with an unaffiliated third party for all energy produced by the facility.

In January 2019, we purchased an 80% membership interest in Upstream, a wind generating facility 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.

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 March 2017 and its dissolution in October 2018), Wisvest (prior to the sale of its assets in April 2016), WECC, WBS, PDL, and ITF (prior to the sale of this business in February 2016).

Wispark develops and invests in real estate and had $40.7 million in real estate holdings at December 31, 2018. WBS is a wholly owned centralized service company that provides administrative and general support services to our regulated utilities, as well as certain services to our nonregulated entities. PDL owns distributed renewable solar projects.

WECC was originally formed to invest in non-utility projects such as low income housing developments, but no longer has significant operations.

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 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

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.

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.

WISCONSIN SEGMENT CONTRIBUTION TO OPERATING INCOME

For the periods presented in this report, 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.

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

Electric Sales Volumes	Year Ended December 31 MWh *(in thousands)* 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.

Natural Gas Sales Volumes	Year Ended December 31 Therms *(in millions)* 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

Weather	Year Ended December 31 Degree Days 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.

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.
- 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.

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.

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.

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.

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.

(in millions)	Year Ended December 31 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:

(in millions)	Year Ended December 31 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:

Natural Gas Sales Volumes	Therms *(in millions)* 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

Weather *	Degree Days 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 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 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%.

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.
- 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.
- 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.
- 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.

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.

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.

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.

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.

(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.

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.

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.

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.

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.

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.

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.

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 $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.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity, and Capital Resources – Market Risks and Other Significant Risks, 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.

WEC ENERGY GROUP, INC.
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.

WEC ENERGY GROUP, INC.
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.

WEC ENERGY GROUP, INC.
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.

WEC ENERGY GROUP, INC.
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.

WEC ENERGY GROUP, INC.
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.

WEC ENERGY GROUP, INC.
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

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.

WEC ENERGY GROUP, INC.
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.

(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 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.

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.

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.

(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.

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 100% bonus depreciation. Bishop Hill III is included in the non-utility energy infrastructure segment.

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

(in millions)	
Current assets	$ 1.4
Net property, plant, and equipment	190.2
Other long-term assets *	4.5
Current liabilities	(1.6)
Long-term liabilities	(8.3)
Noncontrolling interest	(18.8)
Total purchase price	**$ 167.4**

* Represents restricted cash.

Acquisition of a Wind Generation Facility in Wisconsin

In April 2018, WPS, along with two unaffiliated 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. The aggregate purchase price was $172.9 million of which WPS's proportionate share was 44.6%, or $77.1 million. In addition, we incurred transaction costs that are recorded to a regulatory asset. Since 2008 and up until the acquisition, WPS purchased 44.6% of the facility's energy output under a power purchase agreement.

The table below shows the allocation of the purchase price to the assets acquired at the date of the acquisition, which are included in rate base.

(in millions)	
Current assets	$ 0.2
Net property, plant, and equipment	76.9
Total purchase price	**$ 77.1**

Under a joint ownership agreement with the two other utilities, WPS is entitled to its share of generating capability and output of the facility equal to its ownership interest. WPS is also paying its ownership share of additional capital expenditures and operating expenses. Forward Wind Energy Center is included in the Wisconsin segment.

Acquisition of Natural Gas Storage Facilities in Michigan

In June 2017, we completed the acquisition of Bluewater for $226.0 million. Bluewater owns natural gas storage facilities in Michigan that provide approximately one-third of the current storage needs for our Wisconsin natural gas utilities. In addition, we incurred $4.9 million of acquisition related costs that are recorded as a regulatory asset.

The table below shows the allocation of the purchase price to the assets acquired and liabilities assumed at the date of the acquisition. The excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed was recognized as goodwill. Bluewater is included in the non-utility energy infrastructure segment.

(in millions)	
Current assets	$ 2.0
Net property, plant, and equipment	217.6
Goodwill	7.3
Current liabilities	(0.9)
Total purchase price	**$ 226.0**

Acquisition of a Wind Generation Facility in Nebraska

In January 2019, we completed the acquisition of an 80% membership interest in Upstream, a commercially operational 202.5 MW wind generating facility, for $276.0 million. Upstream is located in Antelope County, Nebraska and 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. Upstream is included in the non-utility energy infrastructure segment.

NOTE 3—DISPOSITIONS

Wisconsin Segment

Sale of Milwaukee County Power Plant

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. During the second quarter of 2016, we recorded a pre-tax gain on the sale of $10.9 million ($6.5 million after tax), which was included in other operation and maintenance on our income statements. The assets included in the sale were not material and, therefore, were not presented as held for sale. The results of operations of this plant remained in continuing operations through the sale date as the sale did not represent a shift in our corporate strategy and did not have a major effect on our operations and financial results.

Corporate and Other Segment

Sale of Bostco LLC Real Estate Holdings

In March 2017, we sold the remaining real estate holdings of Bostco located in downtown Milwaukee, Wisconsin, which included retail, office, and residential space, and in October 2018, Bostco was dissolved. During the first quarter of 2017, we recorded an insignificant gain on the sale, which was included in other income, net on our income statements. The assets included in the sale were not material and, therefore, were not presented as held for sale. The results of operations associated with these assets remained in continuing operations through the sale date as the sale did not represent a shift in our corporate strategy and did not have a major effect on our operations and financial results.

Sale of Certain Assets of Wisvest LLC

In April 2016, as part of the MCPP sale transaction, we sold the chilled water generation and distribution assets of Wisvest, which are used to provide chilled water services to the Milwaukee Regional Medical Center hospitals and other campus buildings. During the second quarter of 2016, we recorded a pre-tax gain on the sale of $19.6 million ($11.8 million after tax), which was included in other income, net on our income statements. The assets included in the sale were not material and, therefore, were not presented as held for sale. The results of operations associated with these assets remained in continuing operations through the sale date as the sale did not represent a shift in our corporate strategy and did not have a major effect on our operations and financial results.

Sale of Integrys Transportation Fuels, LLC

Through a series of transactions in the fourth quarter of 2015 and the first quarter of 2016, we sold ITF, a provider of CNG fueling services and a single-source provider of CNG fueling facility design, construction, operation, and maintenance. There was no gain or loss recorded on the sales, as ITF's assets and liabilities were adjusted to fair value through purchase accounting. The results of operations of ITF remained in continuing operations through the sale date as the sale of ITF did not represent a shift in our corporate strategy and did not have a major effect on our operations and financial results. The pre-tax profit or loss of this component was not material through the sale date in 2016.

NOTE 4—OPERATING REVENUES

Disaggregation of Operating Revenues

The following tables present our operating revenues disaggregated by revenue source. We disaggregate revenues into categories that depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors. For our segments, revenues are further disaggregated by electric and natural gas operations and then by customer class. Each customer class within our electric and natural gas operations have different expectations of service, energy and demand requirements, and are impacted by regulatory activities within their jurisdictions.

Comparable amounts have not been presented for the years ended December 31, 2017 and 2016, due to our adoption of ASU 2014-09, Revenues from Contracts with Customers, under the modified retrospective method. See Note 1(d), Operating Revenues, for more information about our significant accounting policies related to operating revenues.

(in millions)	Wisconsin	Illinois	Other States	Total Utility Operations	Electric Transmission	Non-Utility Energy Infrastructure	Corporate and Other	Reconciling Eliminations	WEC Energy Group Consolidated
Year ended December 31, 2018									
Electric	$ 4,432.4	$ —	$ —	$ 4,432.4	$ —	$ —	$ —	$ —	$ 4,432.4
Natural gas	1,350.6	1,406.9	428.4	3,185.9	—	45.4 *	—	(36.4)	3,194.9
Total utility revenues	5,783.0	1,406.9	428.4	7,618.3	—	45.4	—	(36.4)	7,627.3
Other non-utility revenues	—	0.2	16.1	16.3	—	34.6	7.9	(5.8)	53.0
Total revenues from contracts with customers	5,783.0	1,407.1	444.5	7,634.6	—	80.0	7.9	(42.2)	7,680.3
Other operating revenues	11.7	(7.1)	(6.3)	(1.7)	—	388.4	0.8	(388.3)	(0.8)
Total operating revenues	$ 5,794.7	$ 1,400.0	$ 438.2	$ 7,632.9	$ —	$ 468.4	$ 8.7	$ (430.5)	$ 7,679.5

* Represents natural gas operating revenues from Bluewater.

Revenues from Contracts with Customers

Electric Utility Operating Revenues

The following table disaggregates electric utility operating revenues into customer class:

(in millions)	Electric Utility Operating Revenues Year ended December 31, 2018
Residential	$ 1,636.3
Small commercial and industrial	1,408.6
Large commercial and industrial	912.2
Other	29.9
Total retail revenues	3,987.0
Wholesale	210.1
Resale	192.2
Steam	24.1
Other utility revenues	19.0
Total electric utility operating revenues	$ 4,432.4

Natural Gas Utility Operating Revenues

The following table disaggregates natural gas utility operating revenues into customer class:

(in millions)	Wisconsin	Illinois	Other States	Total Natural Gas Utility Operating Revenues
Year Ended December 31, 2018				
Residential	$ 834.5	$ 877.5	$ 263.3	$ 1,975.3
Commercial and industrial	436.7	266.9	140.0	843.6
Total retail revenues	1,271.2	1,144.4	403.3	2,818.9
Transport	70.8	244.1	31.8	346.7
Other utility revenues *	8.6	18.4	(6.7)	20.3
Total natural gas utility operating revenues	$ 1,350.6	$ 1,406.9	$ 428.4	$ 3,185.9

* Includes amounts collected from (refunded to) customers for purchased gas adjustment costs.

Other Non-Utility Operating Revenues

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

(in millions)	Year Ended December 31, 2018
We Power revenues	$ 25.3
Appliance service revenues	15.9
Distributed renewable solar project revenues	8.0
Wind generation revenues	3.6
Other	0.2
Total other non-utility operating revenues	$ 53.0

Other Operating Revenues

Other operating revenues consist primarily of the following:

(in millions)	Year Ended December 31, 2018
Alternative revenues *	$ (45.6)
Late payment charges	40.3
Leases	4.5
Total other operating revenues	$ (0.8)

* Negative amounts can result from alternative revenues being reversed to revenues from contracts with customers as the customer is billed for these alternative revenues. Negative amounts can also result from revenues to be refunded to customers subject to decoupling mechanisms and wholesale true-ups, as discussed in Note 1(d), Operating Revenues.

NOTE 5—REGULATORY ASSETS AND LIABILITIES

The following regulatory assets were reflected on our balance sheets as of December 31:

(in millions)	2018	2017	See Note
Regulatory assets [1] [2]			
Pension and OPEB costs [3]	**$ 1,193.5**	$ 1,142.0	18
Plant retirements	**832.3**	15.1	6
Environmental remediation costs [4]	**687.1**	676.6	22
Income tax related items [5]	**369.1**	15.7	14
SSR	**316.7**	298.9	24
AROs	**185.4**	192.2	8
Electric transmission costs	**58.1**	221.0	24
We Power generation [6]	**43.0**	71.3	
Uncollectible expense [7]	**38.7**	35.1	1(d)
Energy efficiency programs [8]	**14.0**	24.6	
Other, net	**117.9**	147.9	
Total regulatory assets	**$ 3,855.8**	$ 2,840.4	
Balance Sheet Presentation			
Current assets	**$ 50.7**	$ 37.2	
Regulatory assets	**3,805.1**	2,803.2	
Total regulatory assets	**$ 3,855.8**	$ 2,840.4	

(1) Based on prior and current rate treatment, we believe it is probable that our utilities will continue to recover from customers the regulatory assets in this table. In accordance with GAAP, our regulatory assets do not include the allowance for ROE that is capitalized for regulatory purposes. This allowance was $18.2 million and $17.7 million at December 31, 2018 and 2017, respectively.

(2) As of December 31, 2018, we had $125.4 million of regulatory assets not earning a return, $104.1 million of regulatory assets earning a return based on short-term interest rates, and $316.7 million of regulatory assets earning a return based on long-term interest rates. The regulatory assets not earning a return primarily relate to certain environmental remediation costs, the recovery of which depends on the timing of the actual expenditures, as well as uncollectible expense, unamortized loss on reacquired debt, and our electric real-time market pricing program. The other regulatory assets in the table either earn a return or the cash has not yet been expended, in which case the regulatory assets are offset by liabilities.

(3) Primarily represents the unrecognized future pension and OPEB costs related to our defined benefit pension and OPEB plans. We are authorized recovery of these regulatory assets over the average remaining service life of each plan.

(4) As of December 31, 2018, we had made cash expenditures of $70.7 million related to these environmental remediation costs. The remaining $616.4 million represents our estimated future cash expenditures.

(5) For information on the flow through of tax repairs and the regulatory treatment of the impacts of the Tax Legislation in our various jurisdictions, see Note 24, Regulatory Environment.

(6) Represents amounts recoverable from customers related to WE's costs of the generating units leased from We Power, including subsequent capital additions.

(7) Represents amounts recoverable from customers related to our uncollectible expense tracking mechanisms and riders. These mechanisms allow us to recover or refund the difference between actual uncollectible write-offs and the amounts recovered in rates.

(8) Represents amounts recoverable from customers related to programs at the utilities designed to meet energy efficiency standards.

The following regulatory liabilities were reflected on our balance sheets as of December 31:

(in millions)	2018	2017	See Note
Regulatory liabilities			
Income tax related items [1]	**$ 2,406.6**	$ 2,134.1	14
Removal costs [2]	**1,329.6**	1,294.9	
Pension and OPEB costs [3]	**238.3**	114.2	18
Mines deferral [4]	**120.8**	95.1	
Energy costs refundable through rate adjustments [5]	**39.6**	42.0	
Energy efficiency programs [6]	**31.7**	21.1	
Uncollectible expense [7]	**30.5**	24.7	1(d)
Decoupling	**30.5**	1.8	24
Earnings sharing mechanisms	**30.0**	2.5	24
Derivatives	**16.4**	11.0	1(o)
Other, net	**14.4**	19.0	
Total regulatory liabilities	**$ 4,288.4**	$ 3,760.4	
Balance Sheet Presentation			
Current liabilities	**$ 36.8**	$ 41.8	
Regulatory liabilities	**4,251.6**	3,718.6	
Total regulatory liabilities	**$ 4,288.4**	$ 3,760.4	

(1) For information on the regulatory treatment of the impacts of the Tax Legislation in our various jurisdictions, see Note 24, Regulatory Environment.

(2) Represents amounts collected from customers to cover the future cost of property, plant, and equipment removals that are not legally required. Legal obligations related to the removal of property, plant, and equipment are recorded as AROs.

(3) Primarily represents the unrecognized future pension and OPEB benefits related to our defined benefit pension and OPEB plans. We will amortize these regulatory liabilities into net periodic benefit cost over the average remaining service life of each plan.

(4) Represents the deferral of revenues less the associated cost of sales related to Tilden, which were not included in the PSCW's 2015 rate order. We intend to request that this deferral be applied for the benefit of Wisconsin retail electric customers in a future rate proceeding.

(5) Represents an over-collection of energy costs that will be refunded to customers in the future. When the rates we charge to customers include energy costs that are higher than our actual energy costs, any over-collection outside of the allowable energy cost price variance is refunded to customers.

(6) Represents amounts refundable to customers related to programs at the utilities designed to meet energy efficiency standards.

(7) Represents amounts refundable to customers related to our uncollectible expense tracking mechanisms and riders. These mechanisms allow us to recover or refund the difference between actual uncollectible write-offs and the amounts recovered in rates.

NOTE 6—PROPERTY, PLANT, AND EQUIPMENT

Property, plant, and equipment consisted of the following at December 31:

(in millions)	2018	2017
Electric – generation	**$ 6,410.6**	$ 6,071.8
Electric – distribution	**6,534.6**	6,137.5
Natural gas – distribution, storage, and transmission	**10,766.3**	10,055.9
Property, plant, and equipment to be retired, net	**174.8**	930.6
Other	**1,649.1**	1,381.5
Less: Accumulated depreciation	**7,573.6**	7,021.8
Net	**17,961.8**	17,555.5
CWIP	**707.5**	508.2
Net utility property, plant, and equipment	**18,669.3**	18,063.7
We Power generation	**3,244.4**	3,215.9
Renewable generation	**193.3**	—
Natural gas storage	**244.8**	244.8
Net non-utility energy infrastructure	**3,682.5**	3,460.7
Corporate services	**171.0**	169.6
Other	**127.1**	166.9
Less: Accumulated depreciation	**731.5**	671.3
Net	**3,249.1**	3,125.9
CWIP	**82.5**	157.4
Net non-utility and other property, plant, and equipment	**3,331.6**	3,283.3
Total property, plant, and equipment	**$ 22,000.9**	$ 21,347.0

Wisconsin Segment Plant to be Retired

We have evaluated future plans for our older and less efficient fossil fuel generating units and have either retired or announced the retirement of the plants identified below. In December 2017, a severance liability in the amount of $29.4 million was recorded in other current liabilities on our balance sheets within the Wisconsin segment related to these plant retirements.

(in millions)	
Severance liability at December 31, 2017	$ 29.4
Severance payments	**(10.7)**
Other	**(3.0)**
Total severance liability at December 31, 2018	**$ 15.7**

Pleasant Prairie Power Plant

The Pleasant Prairie power plant was retired effective April 10, 2018. The carrying value of this plant was $645.9 million at December 31, 2018. This amount included the net book value of $749.5 million, which was classified as a regulatory asset on our balance sheet. In addition, a $103.6 million cost of removal reserve related to the Pleasant Prairie power plant was classified as a regulatory liability at December 31, 2018. WE continues to amortize this regulatory asset on a straight-line basis using the composite depreciation rates approved by the PSCW before this plant was retired. Amortization is included in depreciation and amortization in the income statement. WE has FERC approval to continue to collect the carrying value of the Pleasant Prairie power plant using the approved composite depreciation rates, in addition to a return on the remaining carrying value. However, this approval is subject to refund while the FERC completes its prudency review. WE will address the accounting and regulatory treatment related to the retirement of Pleasant Prairie with the PSCW in conjunction with its anticipated 2019 rate case. The physical dismantlement of the plant will not occur immediately. It may take several years to finalize long-term plans for the site. See Note 22, Commitments and Contingencies, for more information.

Presque Isle Power Plant

In October 2017, the MPSC approved UMERC's application to construct and operate approximately 180 MW of natural gas-fired generation in the Upper Peninsula of Michigan. Upon receiving this approval, retirement of the PIPP generating units became probable. Pursuant to MISO's April 2018 approval of the retirement of the plant, the PIPP units are required to be retired on or before May 31, 2019. The carrying value of the PIPP units was $174.8 million at December 31, 2018. This amount included net book value of $185.4 million, which was classified as plant to be retired within property, plant, and equipment on our balance sheet. In addition, a $10.6 million cost of removal reserve related to the PIPP units was classified as a regulatory liability at December 31, 2018. These units are included in rate base, and WE continues to depreciate them on a straight-line basis using the composite depreciation rates approved by the PSCW. Upon retirement of PIPP, WE will file with the FERC for approval to continue to collect the carrying value of the PIPP using the current approved composite depreciation rates, in addition to a return on the remaining carrying value. WE will address the accounting and regulatory treatment related to the retirement of the PIPP with the PSCW in conjunction with its anticipated 2019 Wisconsin rate case, and also expects that the retirement will be addressed by the MPSC. See Note 24, Regulatory Environment, for more information regarding the new natural gas-fired generation.

Pulliam Power Plant

In connection with a MISO ruling, WPS retired Pulliam Units 7 and 8 effective October 21, 2018. The carrying value of the Pulliam units was $33.8 million at December 31, 2018. This amount included the net book value of $57.2 million, which was classified as a regulatory asset on our balance sheet. In addition, a $23.4 million cost of removal reserve related to the Pulliam units was classified as a regulatory liability at December 31, 2018. WPS continues to amortize this regulatory asset on a straight-line basis using the composite depreciation rates approved by the PSCW before these generating units were retired. Amortization is included in depreciation and amortization in the income statement. WPS has FERC approval to continue to collect the carrying value of the Pulliam power plant using the approved composite depreciation rates, in addition to a return on the remaining carrying value. FERC has completed its prudency review of Pulliam, concluding that the retirement of this plant was prudent. WPS will address the accounting and regulatory treatment related to the retirement of the Pulliam power plant with the PSCW in conjunction with its anticipated 2019 rate case. See Note 22, Commitments and Contingencies, for more information

Edgewater Unit 4

The Edgewater 4 generating unit was retired effective September 28, 2018. The carrying value of the generating unit was $8.1 million at December 31, 2018. This amount included the net book value of WPS's ownership share of this generating unit of $10.0 million, which was classified as a regulatory asset on our balance sheet. In addition, a $1.9 million cost of removal reserve related to the Edgewater 4 generating unit was classified as a regulatory liability at December 31, 2018. WPS continues to amortize this regulatory asset on a straight-line basis using the composite depreciation rates approved by the PSCW before this generating unit was retired. Amortization is included in depreciation and amortization in the income statement. WPS has FERC approval to continue to collect the carrying value of the Edgewater 4 generating unit using the approved composite depreciation rates, in addition to a return on the remaining carrying value. FERC has completed its prudency review of Edgewater 4, concluding that the retirement of this plant was prudent. WPS will address the accounting and regulatory treatment related to the retirement of the Edgewater 4 generating unit with the PSCW in conjunction with its anticipated 2019 rate case. See Note 22, Commitments and Contingencies, for more information.

NOTE 7—JOINTLY OWNED UTILITY FACILITIES

We Power and WPS hold joint ownership interests in certain electric generating facilities. They are entitled to their share of generating capability and output of each facility equal to their respective ownership interest. They pay their ownership share of additional construction costs and have supplied their own financing for all jointly owned projects. We record We Power's and WPS's proportionate share of significant jointly owned electric generating facilities as property, plant, and equipment on the balance sheets.

We Power leases its ownership interest in ER 1 and ER 2 to WE, and WE operates these units. WE and WPS record their respective share of fuel inventory purchases and operating expenses, unless specific agreements have been executed to limit their maximum exposure to additional costs. WE's and WPS's proportionate share of direct expenses for the joint operation of these plants is recorded in operating expenses in the income statements.

Information related to jointly owned utility facilities at December 31, 2018 was as follows:

	We Power	WPS		
(in millions, except for percentages and MW)	Elm Road Generating Station Units 1 and 2	Weston Unit 4	Columbia Energy Center Units 1 and 2 [(2)]	Forward Wind Energy Center
Ownership	83.34%	70.0%	28.1%	44.6%
Share of rated capacity (MW) [(1)]	1,056.8	384.9	314.8	8.7
In-service date	2010 and 2011	2008	1975 and 1978	2008
Property, plant, and equipment	$ 2,450.6	$ 615.4	$ 438.8	$ 123.7
Accumulated depreciation	$ (394.1)	$ (205.2)	$ (132.2)	$ (43.7)
CWIP	$ 1.8	$ 1.9	$ 0.3	$ 0.1

(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) Columbia Energy Center (Columbia) is jointly owned by Wisconsin Power and Light (WPL), Madison Gas and Electric (MGE), and WPS. In October 2016, WPL received an order from the PSCW approving amendments to the Columbia joint operating agreement between the parties allowing WPS and MGE to forgo certain capital expenditures at Columbia. As a result, WPL will incur these capital expenditures in exchange for a proportional increase in its ownership share of Columbia. Based upon the additional capital expenditures WPL expects to incur through June 1, 2020, WPS's ownership interest would decrease to 27.5%.

NOTE 8—ASSET RETIREMENT OBLIGATIONS

Our utilities have recorded AROs primarily for the removal of natural gas distribution mains and service pipes (including asbestos and polychlorinated biphenyls [PCBs]); asbestos abatement at certain generation and substation facilities, office buildings, and service centers; the removal and dismantlement of biomass and hydro generation facilities; the dismantling of wind generation projects; the disposal of PCB-contaminated transformers; the closure of fly-ash landfills at certain generation facilities; and the removal of above ground storage tanks. Regulatory assets and liabilities are established by our utilities to record the differences between ongoing expense recognition under the ARO accounting rules and the rate-making practices for retirement costs authorized by the applicable regulators.

AROs have also been recorded at Bishop Hill III and PDL for the dismantling of wind generation projects and the removal of solar equipment components, respectively.

On our balance sheets, AROs are recorded within other long-term liabilities. The following table shows changes to our AROs during the years ended December 31:

(in millions)	2018	2017	2016
Balance as of January 1	**$ 573.7**	$ 557.7	$ 571.2
Accretion	**28.0**	27.5	28.3
Additions and revisions to estimated cash flows	**(104.5)** (1)	26.5 (2)	—
Liabilities settled	**(35.8)**	(38.0)	(41.8)
Balance as of December 31	**$ 461.4**	$ 573.7	$ 557.7

(1) AROs decreased $127.3 million in 2018 due to revisions made to estimated cash flows primarily for changes in the cost to retire natural gas distribution pipe at PGL. Also in 2018, AROs increased $10.7 million as a result of revisions made to estimated cash flows for the abatement of asbestos at WPS's Pulliam power plant, and a $10.9 million ARO was recorded for the legal requirement to dismantle, at retirement, the wind generation projects known as Forward Wind Energy Center and Bishop Hill III. See Note 2, Acquisitions, for more information on Forward Wind Energy Center and Bishop Hill III.

(2) AROs increased $20.5 million in 2017 due to revisions made to estimated cash flows primarily for changes in the cost to retire natural gas distribution pipe at PGL and NSG.

NOTE 9—GOODWILL

Goodwill represents the excess of the cost of an acquisition over the fair value of the identifiable net assets acquired. The following table shows changes to our goodwill balances by segment during the years ended December 31, 2018 and 2017:

	Wisconsin		Illinois		Other States		Non-Utility Energy Infrastructure		Total	
(in millions)	2018	2017	2018	2017	2018	2017	2018	2017	2018	2017
Goodwill balance as of January 1	**$2,104.3**	$2,104.3	**$758.7**	$758.7	**$183.2**	$183.2	**$ 7.3**	$ —	**$3,053.5**	$3,046.2
Acquisition of Bluewater (1)	**—**	—	**—**	—	**—**	—	**—**	7.3	**—**	7.3
Adjustment to Bluewater purchase price allocation (1)	**—**	—	**—**	—	**—**	—	**(0.7)**	—	**(0.7)**	—
Goodwill balance as of December 31 (2)	**$2,104.3**	$2,104.3	**$758.7**	$758.7	**$183.2**	$183.2	**$ 6.6**	$ 7.3	**$3,052.8**	$3,053.5

(1) See Note 2, Acquisitions, for more information on the acquisition of Bluewater.

(2) We had no accumulated impairment losses related to our goodwill as of December 31, 2018.

In the third quarter of 2018, annual impairment tests were completed at all of our reporting units that carried a goodwill balance as of July 1, 2018. No impairments resulted from these tests.

NOTE 10—COMMON EQUITY

Stock-Based Compensation Plans

The following table summarizes our pre-tax stock-based compensation expense and the related tax benefit recognized in income for the years ended December 31:

(in millions)	2018	2017	2016
Stock options	**$ 5.2**	$ 3.4	$ 3.5
Restricted stock	**10.7**	5.4	5.8
Performance units	**20.2**	20.2	8.7
Stock-based compensation expense	**$ 36.1**	$ 29.0	$ 18.0
Related tax benefit	**$ 9.9**	$ 11.6	$ 7.2

Stock-based compensation costs capitalized during 2018, 2017, and 2016 were not significant.

Stock Options

The following is a summary of our stock option activity during 2018:

Stock Options	Number of Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life *(in years)*	Aggregate Intrinsic Value *(in millions)*
Outstanding as of January 1, 2018	4,644,214	$ 43.11		
Granted	**710,710**	**$ 65.59**		
Exercised	**(899,391)**	**$ 32.39**		
Forfeited	**(3,000)**	**$ 57.99**		
Outstanding as of December 31, 2018	**4,452,533**	**$ 48.86**	**6.1**	**$ 90.8**
Exercisable as of December 31, 2018	**2,838,609**	**$ 42.77**	**4.9**	**$ 75.2**

The aggregate intrinsic value of outstanding and exercisable options in the above table represents the total pre-tax intrinsic value that would have been received by the option holders had they exercised all of their options on December 31, 2018. This is calculated as the difference between our closing stock price on December 31, 2018, and the option exercise price, multiplied by the number of in-the-money stock options. The intrinsic value of options exercised during the years ended December 31, 2018, 2017, and 2016 was $32.4 million, $33.8 million, and $55.4 million, respectively. The actual tax benefit from option exercises for the same periods was approximately $8.9 million, $13.5 million, and $22.2 million, respectively.

As of December 31, 2018, approximately $3.0 million of unrecognized compensation cost related to unvested and outstanding stock options was expected to be recognized over the next 1.7 years on a weighted-average basis.

During the first quarter of 2019, the Compensation Committee awarded 476,418 non-qualified stock options with a weighted-average exercise price of $68.18 and a weighted-average grant date fair value of $8.60 per option to certain of our officers and other key employees under its normal schedule of awarding long-term incentive compensation.

Restricted Shares

The following restricted stock activity occurred during 2018:

Restricted Shares	Number of Shares	Weighted-Average Grant Date Fair Value
Outstanding and unvested as of January 1, 2018	204,488	$ 54.94
Granted	**156,340**	**$ 64.20**
Released	**(121,060)**	**$ 54.97**
Forfeited	**(5,141)**	**$ 58.68**
Outstanding and unvested as of December 31, 2018	**234,627**	**$ 61.01**

The intrinsic value of restricted stock released was $7.9 million, $5.4 million, and $7.7 million for the years ended December 31, 2018, 2017, and 2016, respectively. The actual tax benefit from released restricted shares for the same years was $2.2 million, $2.1 million, and $3.1 million, respectively.

As of December 31, 2018, approximately $3.2 million of unrecognized compensation cost related to unvested and outstanding restricted stock was expected to be recognized over the next 1.5 years on a weighted-average basis.

During the first quarter of 2019, the Compensation Committee awarded 73,571 restricted shares to certain of our directors, officers, and other key employees under its normal schedule of awarding long-term incentive compensation. The grant date fair value of these awards was $68.18 per share.

Performance Units

During 2018, 2017, and 2016, the Compensation Committee awarded 217,560; 237,650; and 297,305 performance units, respectively, to officers and other key employees under the WEC Energy Group Performance Unit Plan.

Performance units with an intrinsic value of $9.7 million, $6.7 million, and $19.1 million were settled during 2018, 2017, and 2016, respectively. The actual tax benefit from the distribution of performance units for the same years was $2.2 million, $2.1 million, and $6.8 million, respectively.

At December 31, 2018, we had 618,822 performance units outstanding, including dividend equivalents. A liability of $38.1 million was recorded on our balance sheet at December 31, 2018 related to these outstanding units. As of December 31, 2018, approximately $18.4 million of unrecognized compensation cost related to unvested and outstanding performance units was expected to be recognized over the next 1.3 years on a weighted-average basis.

During the first quarter of 2019, we settled performance units with an intrinsic value of $18.6 million. The actual tax benefit from the distribution of these awards was $4.3 million. In January 2019, the Compensation Committee also awarded 148,036 performance units to certain of our officers and other key employees under its normal schedule of awarding long-term incentive compensation.

Restrictions

Our ability as a holding company to pay common stock dividends primarily depends on the availability of funds received from our utility subsidiaries and our non-utility subsidiaries, We Power and ATC Holding. Various financing arrangements and regulatory requirements impose certain restrictions on the ability of our subsidiaries to transfer funds to us in the form of cash dividends, loans, or advances. All of our utility subsidiaries, with the exception of UMERC and MGU, are prohibited from loaning funds to us, either directly or indirectly.

In accordance with their most recent rate orders, WE, WG, and WPS may not pay common dividends above the test year forecasted amounts reflected in their respective rate cases, if it would cause their average common equity ratio, on a financial basis, to fall below their authorized levels of 51%, 49.5%, and 51%, respectively. A return of capital in excess of the test year amount can be paid by each company at the end of the year provided that their respective average common equity ratios do not fall below the authorized levels.

WE may not pay common dividends to us under WE's Restated Articles of Incorporation if any dividends on its outstanding preferred stock have not been paid. In addition, pursuant to the terms of WE's 3.60% Serial Preferred Stock, WE's ability to declare common dividends would be limited to 75% or 50% of net income during a twelve month period if its common stock equity to total capitalization, as defined in the preferred stock designation, is less than 25% and 20%, respectively.

NSG's long-term debt obligations contain provisions and covenants restricting the payment of cash dividends and the purchase or redemption of its capital stock.

ATC Holding's and Bluewater Gas Storage's long-term debt obligations contain a provision requiring them to maintain a total funded debt to capitalization ratio of 65% or less.

WEC Energy Group and Integrys have the option to defer interest payments on their junior subordinated notes, from time to time, for one or more periods of up to 10 consecutive years per period. During any period in which they defer interest payments, they may not declare or pay any dividends or distributions on, or redeem, repurchase or acquire, their respective common stock.

See Note 12, Short-Term Debt and Lines of Credit, for discussion of certain financial covenants related to short-term debt obligations.

As of December 31, 2018, restricted net assets of our consolidated subsidiaries totaled approximately $6.8 billion. Our equity in undistributed earnings of investees accounted for by the equity method were approximately $383 million.

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

Share Purchases

We have instructed our independent agents to purchase shares on the open market to fulfill obligations under various stock-based employee benefit and compensations plans and to provide shares to participants in our dividend reinvestment and stock purchase plan. As a result, no new shares of common stock were issued in 2018, 2017, or 2016.

The following is a summary of shares purchased to fulfill exercised stock options and restricted stock awards during the years ended December 31:

(in millions)	2018	2017	2016
Shares purchased	**1.1**	1.1	1.8
Cost of shares purchased	**$ 72.4**	$ 71.3	$ 108.0

Common Stock Dividends

During the year ended December 31, 2018, our Board of Directors declared common stock dividends which are summarized below:

Date Declared	Date Payable	Per Share	Period
January 18, 2018	March 1, 2018	$0.5525	First quarter
April 19, 2018	June 1, 2018	$0.5525	Second quarter
July 19, 2018	September 1, 2018	$0.5525	Third quarter
October 18, 2018	December 1, 2018	$0.5525	Fourth quarter

On January 17, 2019, our Board of Directors declared a quarterly cash dividend of $0.59 per share, which equates to an annual dividend of $2.36 per share. The dividend is payable on March 1, 2019, to shareholders of record on February 14, 2019. In addition, the Board of Directors affirmed our dividend policy that continues to target a dividend payout ratio of 65-70% of earnings.

NOTE 11—PREFERRED STOCK

The following table shows preferred stock authorized and outstanding at December 31, 2018 and 2017:

(in millions, except share and per share amounts)	Shares Authorized	Shares Outstanding	Redemption Price Per Share	Total
WEC Energy Group				
$.01 par value Preferred Stock	**15,000,000**	**—**	**—**	**$ —**
WE				
$100 par value, Six Per Cent. Preferred Stock	**45,000**	**44,498**	**—**	**4.4**
$100 par value, Serial Preferred Stock	**2,286,500**			
3.60% Series		**260,000**	**$ 101**	**26.0**
$25 par value, Serial Preferred Stock	**5,000,000**	**—**	**—**	**—**
WPS				
$100 par value, Preferred Stock	**1,000,000**	**—**	**—**	**—**
PGL				
$100 par value, Cumulative Preferred Stock	**430,000**	**—**	**—**	**—**
NSG				
$100 par value, Cumulative Preferred Stock	**160,000**	**—**	**—**	**—**
Total				**$ 30.4**

NOTE 12—SHORT-TERM DEBT AND LINES OF CREDIT

The following table shows our short-term borrowings and their corresponding weighted-average interest rates as of December 31:

(in millions, except percentages)	2018	2017
Commercial paper		
Amount outstanding at December 31	**$ 1,440.1**	$ 1,444.6
Average interest rate on amounts outstanding at December 31	**2.92%**	1.77%

Our average amount of commercial paper borrowings based on daily outstanding balances during 2018, was $1,350.7 million with a weighted-average interest rate during the period of 2.32%.

WEC Energy Group, WE, WPS, WG, and PGL have entered into bank back-up credit facilities to maintain short-term credit liquidity which, among other terms, require them to maintain, subject to certain exclusions, a total funded debt to capitalization ratio of 70.0%, 65.0%, 65.0%, 65.0%, and 65.0% or less, respectively. As of December 31, 2018, all companies were in compliance with their respective ratio.

The information in the table below relates to our revolving credit facilities used to support our commercial paper borrowing program, including remaining available capacity under these facilities as of December 31:

(in millions)	Maturity	2018
WEC Energy Group	October 2022	**$ 1,200.0**
WE	October 2022	**500.0**
WPS	October 2022	**400.0**
WG	October 2022	**350.0**
PGL	October 2022	**350.0**
Total short-term credit capacity		**$ 2,800.0**
Less:		
Letters of credit issued inside credit facilities		**$ 3.0**
Commercial paper outstanding		**1,440.1**
Available capacity under existing agreements		**$ 1,356.9**

Each of these facilities has a renewal provision for two one-year extensions, subject to lender approval.

The bank back-up credit facilities contain customary covenants, including certain limitations on the respective companies' ability to sell assets. The credit facilities also contain customary events of default, including payment defaults, material inaccuracy of representations and warranties, covenant defaults, bankruptcy proceedings, certain judgments, Employee Retirement Income Security Act of 1974 defaults, and change of control. In addition, pursuant to the terms of our credit agreement, we must ensure that certain of our subsidiaries comply with several of the covenants contained therein.

NOTE 13—LONG-TERM DEBT AND CAPITAL LEASE OBLIGATIONS

See our statements of capitalization for details on our long-term debt.

WEC Energy Group, Inc.

In July 2018, we executed two interest rate swaps with a combined notional value of $250.0 million to hedge the variable interest rate risk associated with our 2007 Junior Notes. The swaps will provide a fixed interest rate of 4.9765% on $250.0 million of the $500.0 million outstanding of 2007 Junior Notes through November 15, 2021.

In June 2018, we issued $600.0 million of 3.375% Senior Notes due June 15, 2021. We used the net proceeds to repay short-term debt, including short-term debt used to redeem at par all $114.9 million outstanding principal amount of Integrys's 2006 Junior Notes, to repay all $300.0 million of our 1.65% Senior Notes that matured in June 2018, and for working capital and general corporate purposes.

Wisconsin Electric Power Company

In October 2018, WE issued $300.0 million of 4.30% Debentures due October 15, 2048, and used the net proceeds to repay short-term debt and for working capital and other corporate purposes.

In July 2018, WE redeemed all $80.0 million of its series of tax-exempt pollution control refunding bonds. From August 2009 until they were called, the bonds were not reported in our long-term debt because they were previously repurchased by WE.

In June 2018, WE's $250.0 million of 1.70% Debentures matured, and the outstanding principal was paid with proceeds received from issuing commercial paper.

Integrys Holding, Inc.

In May 2018, Integrys redeemed at par all $114.9 million outstanding of its 2006 Junior Notes.

Wisconsin Public Service Corporation

In November 2018, WPS issued $400.0 million of 3.35% Senior Notes due November 21, 2021. WPS used the net proceeds to pay all $250.0 million outstanding principal amount of its 1.65% Senior Notes at maturity in December 2018, to repay short-term debt, and for working capital and other corporate purposes.

The Peoples Gas Light and Coke Company

In November 2018, PGL issued $150.0 million of 3.87% Series FFF Bonds due November 1, 2028. The net proceeds were used for general corporate purposes, including funding capital expenditures and the refinancing of short-term debt.

In November 2018, PGL's $5.0 million of 8.00% Series TT Bonds matured, and the outstanding principal was repaid with proceeds from issuing commercial paper.

North Shore Gas Company

In November 2018, NSG issued $50.0 million of 3.87% Series R Bonds due November 1, 2028. The net proceeds were used for general corporate purposes, including funding capital expenditures and the refinancing of short-term debt.

ATC Holding LLC

In December 2018, ATC Holding issued $240.0 million of senior notes. The senior notes were issued in three tranches: $85.0 million of 4.18% Senior Notes due December 20, 2025; $56.5 million of 4.37% Senior Notes due December 20, 2028; and $98.5 million of 4.47% Senior Notes due December 20, 2030. Net proceeds were used to make a special distribution to WEC Energy Group in order to balance ATC Holding's capital structure.

Bluewater Gas Storage, LLC

The long-term debt of Bluewater Gas Storage, a wholly owned subsidiary of Bluewater, amortizes on a mortgage-style basis. During 2019, $2.4 million of Bluewater Gas Storage's outstanding $122.7 million of 3.76% Senior Notes will mature. As a result, this balance was included in the current portion of long-term debt on our balance sheet at December 31, 2018.

W.E. Power, LLC

We Power's outstanding long-term debt below amortizes on a mortgage-style basis.

During 2019, $6.2 million of We Power's outstanding $95.1 million of 4.91% secured notes will mature. As a result, this balance was included in the current portion of long-term debt on our balance sheet at December 31, 2018.

During 2019, $5.2 million of We Power's outstanding $116.6 million of 6.00% secured notes will mature. As a result, this balance was included in the current portion of long-term debt on our balance sheet at December 31, 2018.

During 2019, $12.0 million of We Power's outstanding $182.7 million of 5.209% secured notes will mature. As a result, this balance was included in the current portion of long-term debt on our balance sheet at December 31, 2018.

During 2019, $9.3 million of We Power's outstanding $153.5 million of 4.673% secured notes will mature. As a result, this balance was included in the current portion of long-term debt on our balance sheet at December 31, 2018.

Bonds and Notes

The following table shows the future maturities of our long-term debt outstanding (excluding obligations under capital leases) as of December 31, 2018:

(in millions)	Payments
2019	$ 360.1
2020	686.9
2021	1,338.8
2022	40.8
2023	42.8
Thereafter	7,918.2
Total	$ 10,387.6

We amortize debt premiums, discounts, and debt issuance costs over the life of the debt and we include the costs in interest expense.

In connection with our outstanding 2007 Junior Notes, we executed a Replacement Capital Covenant dated May 11, 2007 (RCC), which we amended on June 29, 2015, for the benefit of persons that buy, hold, or sell a specified series of our long-term indebtedness (covered debt). Our 6.20% Senior Notes due April 1, 2033 have been designated as the covered debt under the RCC. The RCC provides that we may not redeem, defease, or purchase, and that our subsidiaries may not purchase, any 2007 Junior Notes on or before May 15, 2037, unless, subject to certain limitations described in the RCC, we have received a specified amount of proceeds from the sale of qualifying securities.

Effective August 2023, Integrys's $400.0 million of 2013 6.00% Junior Subordinated Notes due 2073 will bear interest at the three-month LIBOR plus 322 basis points and will reset quarterly.

Certain long-term debt obligations contain financial and other covenants. Failure to comply with these covenants could result in an event of default, which could result in the acceleration of outstanding debt obligations.

Obligations Under Capital Leases

In 1997, WE entered into a 25-year power purchase contract with an unaffiliated independent power producer. The contract, for 236 MW of firm capacity from a natural gas-fired cogeneration facility, includes zero minimum energy requirements. When the contract expires in 2022, WE may, at its option and with proper notice, renew for another 10 years or purchase the generating facility at fair value or allow the contract to expire. We account for this contract as a capital lease and recorded the leased facility and corresponding obligation under the capital lease at the estimated fair value of the plant's electric generating facilities. We are amortizing the leased facility on a straight-line basis over the original 25-year term of the contract.

We treat the long-term power purchase contract as an operating lease for rate-making purposes and we record our minimum lease payments as cost of sales on our income statements. We paid a total of $7.7 million, $7.2 million, and $37.6 million in minimum lease payments during 2018, 2017, and 2016, respectively. We record the difference between the minimum lease payments and the sum of imputed interest and amortization costs calculated under capital lease accounting as a deferred regulatory asset on our balance sheets. Minimum lease payments are a function of the 236 MW of firm capacity we receive from the plant and the fixed monthly capacity rate published in the lease. Due to the timing and the amounts of the minimum lease payments, the regulatory asset increased to approximately $78.5 million during 2009, at which time the regulatory asset began to be reduced to zero over the remaining life of the contract. The total obligation under the capital lease was $23.3 million as of December 31, 2018, and will decrease to zero over the remaining life of the contract.

For information on how the implementation of ASU 2016-02, Leases (Topic 842), is expected to impact the classification of lease expense effective January 1, 2019, for this capital lease, see Note 27, New Accounting Pronouncements.

The following is a summary of our capitalized leased facilities as of December 31:

(in millions)	2018	2017
Long-term power purchase commitment	**$ 140.3**	$ 140.3
Accumulated amortization	**(120.9)**	(115.2)
Total leased facilities	**$ 19.4**	$ 25.1

Future minimum lease payments under our capital lease and the present value of our net minimum lease payments as of December 31, 2018 are as follows:

(in millions)	Payments
2019	$ 15.5
2020	16.4
2021	17.2
2022	7.6
Thereafter	—
Total minimum lease payments	56.7
Less: Estimated executory costs	(26.1)
Net minimum lease payments	30.6
Less: Interest	(7.3)
Present value of net minimum lease payments	23.3
Less: Due currently	(4.9)
Long-term obligations under capital lease	**$ 18.4**

NOTE 14—INCOME TAXES

Income Tax Expense

The following table is a summary of income tax expense for the years ended December 31:

(in millions)	2018	2017	2016
Current tax (benefit) expense	**$ (127.5)**	$ 111.8	$ 72.7
Deferred income taxes, net	**300.1**	274.4	498.7
Investment tax credit, net	**(2.8)**	(2.7)	(4.9)
Total income tax expense	**$ 169.8**	$ 383.5	$ 566.5

Statutory Rate Reconciliation

The provision for income taxes for each of the years ended December 31 differs from the amount of income tax determined by applying the applicable United States statutory federal income tax rate to income before income taxes as a result of the following:

	2018		2017 [2]		2016	
(in millions)	Amount	Effective Tax Rate	Amount	Effective Tax Rate	Amount	Effective Tax Rate
Expected tax at statutory federal tax rates	**$ 258.1**	**21.0 %**	$ 555.5	35.0 %	$ 526.4	35.0 %
State income taxes net of federal tax benefit	**71.8**	**5.8 %**	100.8	6.4 %	72.8	4.8 %
Tax repairs [1]	**(120.7)**	**(9.8)%**	—	— %	—	— %
Federal excess amortization	**(16.8)**	**(1.4)%**	—	— %	—	— %
Production tax credits	**(12.1)**	**(1.0)%**	(16.8)	(1.1)%	(15.7)	(1.1)%
AFUDC – Equity	**(3.2)**	**(0.3)%**	(4.0)	(0.3)%	(8.8)	(0.6)%
Investment tax credit restored	**(2.8)**	**(0.2)%**	(2.7)	(0.2)%	(4.9)	(0.3)%
Federal tax reform	**—**	**— %**	(226.9)	(14.3)%	—	— %
Other, net	**(4.5)**	**(0.3)%**	(22.4)	(1.4)%	(3.3)	(0.2)%
Total income tax expense	**$ 169.8**	**13.8 %**	$ 383.5	24.1 %	$ 566.5	37.6 %

(1) In accordance with a settlement agreement with the PSCW, WE will flow through the tax benefit of its repair related deferred tax liabilities in 2018 and 2019, to maintain certain regulatory asset balances at their December 31, 2017 levels. The flow through treatment of the repair related deferred tax liabilities offsets the negative income statement impact of holding the regulatory assets level, resulting in no change to net income. See Note 24, Regulatory Environment, for more information about the impact of the Tax Legislation and the Wisconsin rate settlement.

(2) In 2017, the net impact of tax reform in the amount of $206.7 million is represented in both the Federal tax reform and State income taxes net of federal tax benefit lines above.

Deferred Income Tax Assets and Liabilities

On December 22, 2017, the Tax Legislation was signed into law. For businesses, the Tax Legislation reduced the corporate federal tax rate from a maximum of 35% to a 21% rate effective January 1, 2018. In December 2017, we recorded a tax benefit related to the re-measurement of our deferred taxes in the amount of $2,657 million. Accordingly, the tax benefit related to our regulated utilities was recorded as both an increase to regulatory liabilities as well as a decrease to certain existing regulatory assets as of December 31, 2017. The effects of the Tax Legislation primarily at our non-utility energy infrastructure and corporate and other segments resulted in the recording of an income tax benefit of approximately $206.7 million for the year ended December 31, 2017. This tax benefit was primarily due to a re-measurement of deferred tax assets and liabilities.

On December 22, 2017, the SEC staff issued guidance in Staff Accounting Bulletin 118 (SAB 118), Income Tax Accounting Implications of the Tax Cuts and Jobs Act, which provided for a measurement period of up to one year from the enactment date to complete accounting under GAAP for the tax effects of the legislation. Due to the complex and comprehensive nature of the enacted tax law changes, and their application under GAAP, certain amounts related to bonus depreciation and future tax benefit utilization recorded in the financial statements as a result of the Tax Legislation were considered "provisional" and subject to revision at December 31, 2017, and through 2018, as discussed in SAB 118.

In 2018, we considered all available guidance from industry and income tax authorities related to these tax items, and revised our Alternative Minimum Tax Credit valuation allowance, and revised our estimates for re-measurement of deferred income taxes related to guidance on bonus depreciation. At December 31, 2018, we no longer considered any amounts related to bonus depreciation and future tax benefit utilization "provisional." However, any further amendments or technical corrections to the Tax Legislation could subject these tax items to revision.

The components of deferred income taxes as of December 31 were as follows:

(in millions)	**2018**	**2017**
Deferred tax assets		
Tax gross up – regulatory items	**$ 579.2**	$ 585.8
Deferred revenues	**129.3**	128.8
Future tax benefits	**70.6**	303.9
Employee benefits and compensation	**—**	164.2
Property-related	**—**	24.4
Other	**194.4**	185.0
Total deferred tax assets	**973.5**	1,392.1
Valuation allowance	**(11.4)**	(15.7)
Net deferred tax assets	**$ 962.1**	$ 1,376.4
Deferred tax liabilities		
Property-related	**$ 3,436.9**	$ 3,464.6
Investment in transmission affiliate	**420.6**	321.2
Deferred costs – Pleasant Prairie	**176.0**	—
Employee benefits and compensation	**121.2**	285.8
Deferred transmission costs	**55.4**	60.1
Other	**140.1**	244.5
Total deferred tax liabilities	**4,350.2**	4,376.2
Deferred tax liability, net	**$ 3,388.1**	$ 2,999.8

Consistent with rate-making treatment, deferred taxes related to our regulated utilities in the table above are offset for temporary differences that have related regulatory assets and liabilities.

The components of net deferred tax assets associated with federal and state tax benefit carryforwards as of December 31, 2018 and 2017 are summarized in the tables below:

2018 ***(in millions)***	**Gross Value**	**Deferred Tax Effect**	**Valuation Allowance**	**Earliest Year of Expiration**
Future tax benefits as of December 31, 2018				
Federal foreign tax credit	**$ —**	**$ 9.7**	**$ (9.7)**	**2018**
Other federal tax credit	**—**	**39.3**	**(1.7)**	**2038**
State net operating loss	**275.9**	**17.0**	**—**	**2023**
State tax credit	**—**	**4.6**	**—**	**2018**
Balance as of December 31, 2018	**$ 275.9**	**$ 70.6**	**$ (11.4)**	

2017 *(in millions)*	Gross Value	Deferred Tax Effect	Valuation Allowance	Earliest Year of Expiration
Future tax benefits as of December 31, 2017				
Federal foreign tax credit	$ —	$ 13.5	$ (13.5)	2018
Other federal tax credit	—	259.6	(0.1)	2025
Charitable contribution and capital loss	21.7	8.6	(2.1)	2017
State net operating loss	282.7	17.2	—	2025
State tax credit	—	5.0	—	2017
Balance as of December 31, 2017	$ 304.4	$ 303.9	$ (15.7)	

Valuation allowances of $11.4 million have been established for certain tax benefit carryforwards obtained in the Integrys acquisition based on our projected ability to realize such benefits by offsetting future tax liabilities. Realization is dependent on generating sufficient tax liabilities prior to expiration of the tax benefit carryforwards.

Unrecognized Tax Benefits

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

(in millions)	2018	2017
Balance as of January 1	**$ 17.3**	$ 14.5
Additions for tax positions of prior years	**2.8**	7.9
Additions based on tax positions related to the current year	**0.1**	0.5
Reductions for tax positions of prior years	**(0.2)**	(5.6)
Balance as of December 31	**$ 20.0**	$ 17.3

The amount of unrecognized tax benefits as of December 31, 2018 and 2017, excludes deferred tax assets related to uncertainty in income taxes of $2.0 million and $2.1 million, respectively. As of December 31, 2018 and 2017, the net amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate for continuing operations was $18.0 million and $15.2 million, respectively.

For the years ended December 31, 2018, 2017, and 2016, we recognized $0.5 million of interest expense, $0.6 million of interest income, and $0.2 million of interest expense, respectively, related to unrecognized tax benefits in our income statements. For the years ended December 31, 2018, 2017, and 2016, we recognized no penalties related to unrecognized tax benefits in our income statements. For the year ended December 31, 2018, we had $0.7 million of interest accrued and no penalties accrued related to unrecognized tax benefits on our balance sheets. For the year ended December 31, 2017, we had $0.2 million of interest accrued and no penalties accrued related to unrecognized tax benefits on our balance sheets.

Although analysis of our unrecognized tax benefits is ongoing, the potential estimated decrease in the total amounts of unrecognized tax benefits within the next 12 months are approximately $3.0 million associated with statutes of limitations on certain tax years. We do not anticipate any significant increases in the total amounts of unrecognized tax benefits within the next 12 months.

We file income tax returns in the United States federal jurisdiction and state tax returns based on income in our major state operating jurisdictions of Wisconsin, Illinois, Michigan, and Minnesota. We also file tax returns in other state and local jurisdictions with varying statutes of limitations. As of December 31, 2018, with a few exceptions, we were subject to examination by federal and state or local tax authorities for the 2013 through 2018 tax years in our major operating jurisdictions as follows:

Jurisdiction	Years
Federal	2015–2018
Illinois	2013–2018
Michigan	2014–2018
Minnesota	2014–2018
Wisconsin	2014–2018

NOTE 15—FAIR VALUE MEASUREMENTS

The following tables summarize our financial assets and liabilities that were accounted for at fair value on a recurring basis, categorized by level within the fair value hierarchy:

	December 31, 2018			
(in millions)	Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	$ 6.3	$ 1.8	$ —	$ 8.1
FTRs	—	—	7.4	7.4
Coal contracts	—	0.4	—	0.4
Total derivative assets	$ 6.3	$ 2.2	$ 7.4	$ 15.9
Investments held in rabbi trust	$ 65.0	$ —	$ —	$ 65.0
Derivative liabilities				
Natural gas contracts	$ 4.7	$ 0.8	$ —	$ 5.5
Coal contracts	—	0.1	—	0.1
Interest rate swaps	—	2.3	—	2.3
Total derivative liabilities	$ 4.7	$ 3.2	$ —	$ 7.9

	December 31, 2017			
(in millions)	Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	$ 1.8	$ 3.9	$ —	$ 5.7
Petroleum products contracts	1.2	—	—	1.2
FTRs	—	—	4.4	4.4
Coal contracts	—	1.1	—	1.1
Total derivative assets	$ 3.0	$ 5.0	$ 4.4	$ 12.4
Investments held in rabbi trust	$ 120.7	$ —	$ —	$ 120.7
Derivative liabilities				
Natural gas contracts	$ 7.0	$ 3.8	$ —	$ 10.8
Coal contracts	—	0.8	—	0.8
Total derivative liabilities	$ 7.0	$ 4.6	$ —	$ 11.6

The derivative assets and liabilities listed in the tables above include options, swaps, futures, physical commodity contracts, and other instruments used to manage market risks related to changes in commodity prices and interest rates. They also include FTRs, which are used to manage electric transmission congestion costs in the MISO Energy Markets.

We hold investments in the Integrys rabbi trust. These investments are restricted as they can only be withdrawn from the trust to fund participants' benefits under the Integrys deferred compensation plan and certain Integrys non-qualified pension plans. These investments are included in other long-term assets on our balance sheets. The net unrealized gains included in earnings related to the investments held at the end of the period were $18.8 million for the year ended December 31, 2017. The net unrealized gains included in earnings for the years ended December 31, 2018 and 2016 were not significant.

The following table summarizes the changes to derivatives classified as Level 3 in the fair value hierarchy at December 31:

(in millions)	2018	2017	2016
Balance at the beginning of the period	$ 4.4	$ 5.1	$ 3.6
Realized and unrealized losses	—	—	(0.2)
Purchases	18.4	13.8	15.2
Sales	—	—	(0.2)
Settlements	(15.4)	(14.5)	(13.3)
Balance at the end of the period	$ 7.4	$ 4.4	$ 5.1

Unrealized gains and losses on Level 3 derivatives are deferred as regulatory assets or liabilities. Therefore, these fair value measurements have no impact on earnings. Realized gains and losses on these instruments flow through cost of sales on the income statements.

Fair Value of Financial Instruments

The following table shows the financial instruments included on our balance sheets that are not recorded at fair value at December 31:

	2018		2017	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Preferred stock	**$ 30.4**	**$ 28.3**	$ 30.4	$ 30.5
Long-term debt, including current portion *	**10,335.7**	**10,554.9**	9,561.7	10,341.9

* The carrying amount of long-term debt excludes capital lease obligations of $23.3 million and $27.0 million at December 31, 2018 and December 31, 2017, respectively.

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

NOTE 16—DERIVATIVE INSTRUMENTS

None of our derivatives are designated as hedging instruments, with the exception of our interest rate swaps, which have been designated as cash flow hedges. The following table shows our derivative assets and derivative liabilities:

	December 31, 2018		December 31, 2017	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Other current				
Natural gas contracts	**$ 7.7**	**$ 5.3**	$ 5.6	$ 9.4
Petroleum products contracts	**—**	**—**	1.2	—
FTRs	**7.4**	**—**	4.4	—
Coal contracts	**0.2**	**0.1**	0.6	0.6
Interest rate swaps	**—**	**0.4**	—	—
Total other current	**$ 15.3**	**$ 5.8**	$ 11.8	$ 10.0
Other long-term				
Natural gas contracts	**$ 0.4**	**$ 0.2**	$ 0.1	$ 1.4
Coal contracts	**0.2**	**—**	0.5	0.2
Interest rate swaps	**—**	**1.9**	—	—
Total other long-term	**$ 0.6**	**$ 2.1**	$ 0.6	$ 1.6
Total	**$ 15.9**	**$ 7.9**	$ 12.4	$ 11.6

Realized gains (losses) on derivatives not designated as hedging instruments are primarily recorded in cost of sales on the income statements. Our estimated notional sales volumes and realized gains (losses) were as follows for the years ended:

	December 31, 2018		December 31, 2017		December 31, 2016	
(in millions)	Volume	Gains	Volume	Gains (Losses)	Volume	Gains (losses)
Natural gas contracts	173.2 Dth	**$ 24.6**	123.1 Dth	$ (8.0)	151.1 Dth	$ (59.6)
Petroleum products contracts	6.0 gallons	**1.6**	18.0 gallons	(1.3)	14.7 gallons	(3.2)
FTRs	30.5 MWh	**15.9**	36.2 MWh	14.0	33.7 MWh	13.3
Total		**$ 42.1**		$ 4.7		$ (49.5)

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

	December 31, 2018		December 31, 2017	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Gross amount recognized on the balance sheet	**$ 15.9**	**$ 7.9**	$ 12.4	$ 11.6
Gross amount not offset on the balance sheet	**(4.0)** (1)	**(4.9)** (2)	(4.9)	(9.0) (3)
Net amount	**$ 11.9**	**$ 3.0**	$ 7.5	$ 2.6

(1) Includes cash collateral received of $0.2 million.

(2) Includes cash collateral posted of $1.1 million.

(3) Includes cash collateral posted of $4.1 million.

At December 31, 2018 and 2017, we had posted cash collateral of $2.7 million and $16.2 million, respectively, in our margin accounts. At December 31, 2018, we had also received cash collateral of $0.2 million in our margin accounts. Certain of our derivative and non-derivative commodity instruments contain provisions that could require "adequate assurance" in the event of a material change in our creditworthiness, or the posting of additional collateral for instruments in net liability positions, if triggered by a decrease in credit ratings. We did not have any derivative instruments with specific credit risk-related contingent features that were in a net liability position at December 31, 2018. The aggregate fair value of all derivative instruments with these features that were in a net liability position at December 31, 2017 was $3.7 million. At December 31, 2017, we had not posted any cash collateral related to the credit risk-related contingent features of these commodity instruments. If all of the credit risk-related contingent features contained in derivative instruments in a net liability position had been triggered at December 31, 2017, we would have been required to post collateral of $2.7 million.

Cash Flow Hedges

In July 2018, we executed two interest rate swap agreements with a combined notional value of $250.0 million to hedge the variable interest rate risk associated with our 2007 Junior Notes. The swap agreements will provide a fixed interest rate of 4.9765% on $250.0 million of the $500.0 million of outstanding 2007 Junior Notes through November 15, 2021. As these agreements qualified for cash flow hedge accounting treatment, the related gains and losses are being deferred in accumulated other comprehensive income (OCI) and are being amortized to interest expense as interest is accrued on the 2007 Junior Notes.

During 2015, we settled several forward interest rate swap agreements entered into to mitigate interest rate risk associated with the issuance of $1.2 billion of long-term debt related to the acquisition of Integrys. As these agreements qualified for cash flow hedge accounting treatment, the proceeds of $19.0 million received upon settlement were deferred in accumulated OCI and are being amortized as a decrease to interest expense over the periods in which the interest costs are recognized in earnings.

The table below shows the amounts related to these cash flow hedges recorded in OCI and in earnings at December 31:

(in millions)	**2018**	**2017**	**2016**
Amount of net derivative loss recognized in OCI	**$ (2.9)**	$ —	$ —
Amount of net derivative gain reclassified from accumulated OCI to interest expense	**1.6**	2.2	2.2

We estimate that during the next twelve months, $1.8 million will be reclassified from accumulated OCI as a reduction to interest expense.

Effective January 1, 2019, we adopted ASU 2017-12, Targeted Improvements to Accounting for Hedging Activities. The amendments in this update expand the strategies that qualify for hedge accounting, amend the presentation and disclosure requirements related to hedging activities, and provide overall targeted improvements to simplify hedge accounting in certain situations. The adoption of this standard is not expected to have a material impact on our financial statements.

NOTE 17—GUARANTEES

The following table shows our outstanding guarantees:

		Expiration		
(in millions)	**Total Amounts Committed at December 31, 2018**	**Less Than 1 Year**	**1 to 3 Years**	**Over 3 Years**
Guarantees				
Guarantees supporting commodity transactions of subsidiaries [(1)]	**$ 5.6**	$ 5.6	$ —	$ —
Standby letters of credit [(2)]	**92.6**	13.9	0.2	78.5
Surety bonds [(3)]	**9.2**	9.1	0.1	—
Other guarantees [(4)]	**11.9**	0.5	0.9	10.5
Total guarantees	**$ 119.3**	$ 29.1	$ 1.2	$ 89.0

(1) Consists of $5.6 million to support the business operations of Bluewater.

(2) At our request or the request of our subsidiaries, financial institutions have issued standby letters of credit for the benefit of third parties that have extended credit to our subsidiaries. These amounts are not reflected on our balance sheets.

(3) Primarily for workers compensation self-insurance programs and obtaining various licenses, permits, and rights-of-way. These amounts are not reflected on our balance sheets.

(4) Consists of $11.9 million related to other indemnifications, for which a liability of $10.5 million related to workers compensation coverage was recorded on our balance sheets.

NOTE 18—EMPLOYEE BENEFITS

Pension and Other Postretirement Employee Benefits

We and our subsidiaries have defined benefit pension plans that cover substantially all of our employees, as well as several unfunded non-qualified retirement plans. In addition, we and our subsidiaries offer multiple OPEB plans to employees. The benefits for a portion of these plans are funded through irrevocable trusts, as allowed for income tax purposes. We also offer medical, dental, and life insurance benefits to active employees and their dependents. We expense the costs of these benefits as incurred.

Generally, former Wisconsin Energy Corporation employees who started with the company after 1995 receive a benefit based on a percentage of their annual salary plus an interest credit, while employees who started before 1996 receive a benefit based upon years of service and final average salary. New Wisconsin Energy Corporation management employees hired after December 31, 2014, and certain new represented employees hired after May 1, 2017, receive an annual company contribution to their 401(k) savings plan instead of being enrolled in the defined benefit plans.

For former Integrys employees, the defined benefit pension plans are closed to all new hires. In addition, the service accruals for the defined benefit pension plans were frozen for non-union employees as of January 1, 2013. These employees receive an annual company contribution to their 401(k) savings plan, which is calculated based on age, wages, and full years of vesting service as of December 31 each year.

We use a year-end measurement date to measure the funded status of all of our pension and OPEB plans. Due to the regulated nature of our business, we have concluded that substantially all of the unrecognized costs resulting from the recognition of the funded status of our pension and OPEB plans qualify as a regulatory asset.

The following tables provide a reconciliation of the changes in our plans' benefit obligations and fair value of assets:

	Pension Costs		OPEB Costs	
(in millions)	**2018**	**2017**	**2018**	**2017**
Change in benefit obligation				
Obligation at January 1	**$ 3,163.7**	$ 3,058.8	**$ 818.5**	$ 818.4
Service cost	**47.1**	44.6	**23.7**	24.1
Interest cost	**114.3**	121.8	**29.9**	32.9
Participant contributions	**—**	—	**15.5**	13.4
Plan amendments	**—**	—	**(3.5)**	(36.4)
Actuarial loss (gain)	**(171.8)**	162.6	**(222.6)**	12.9
Benefit payments	**(226.1)**	(224.1)	**(55.4)**	(48.8)
Federal subsidy on benefits paid	**N/A**	N/A	**1.0**	2.0
Transfer	**—**	—	**1.1**	—
Obligation at December 31	**$ 2,927.2**	$ 3,163.7	**$ 608.2**	$ 818.5
Change in fair value of plan assets				
Fair value at January 1	**$ 2,966.8**	$ 2,709.2	**$ 841.5**	$ 773.5
Actual return on plan assets	**(122.2)**	368.7	**(35.2)**	95.9
Employer contributions	**72.3**	113.0	**5.3**	7.5
Participant contributions	**—**	—	**15.5**	13.4
Benefit payments	**(226.1)**	(224.1)	**(55.4)**	(48.8)
Fair value at December 31	**$ 2,690.8**	$ 2,966.8	**$ 771.7**	$ 841.5
Funded status at December 31	**$ (236.4)**	$ (196.9)	**$ 163.5**	$ 23.0

The amounts recognized on our balance sheets at December 31 related to the funded status of the benefit plans were as follows:

	Pension Costs		OPEB Costs	
(in millions)	**2018**	**2017**	**2018**	**2017**
Other long-term assets	**$ 139.1**	$ 143.0	**$ 210.8**	$ 80.5
Pension and OPEB obligations	**375.5**	339.9	**47.3**	57.5
Total net (liabilities) assets	**$ (236.4)**	$ (196.9)	**$ 163.5**	$ 23.0

The accumulated benefit obligation for all defined benefit pension plans was $2,804.9 million and $3,057.7 million as of December 31, 2018 and 2017, respectively.

The following table shows information for pension plans with an accumulated benefit obligation in excess of plan assets. Amounts presented are as of December 31:

(in millions)	2018	2017
Projected benefit obligation	**$ 1,930.8**	$ 679.5
Accumulated benefit obligation	**1,882.2**	630.3
Fair value of plan assets	**1,572.7**	339.6

The following table shows the amounts that have not yet been recognized in our net periodic benefit cost as of December 31:

	Pension Costs		OPEB Costs	
(in millions)	2018	2017	2018	2017
Pre-tax accumulated other comprehensive loss (income) [(1)]				
Net actuarial loss (gain)	**$ 14.5**	$ 10.0	**$ (1.6)**	$ (1.0)
Prior service credits	**—**	—	**(0.1)**	(0.1)
Total	**$ 14.5**	$ 10.0	**$ (1.7)**	$ (1.1)
Net regulatory assets (liabilities) [(2)]				
Net actuarial loss (gain)	**$ 1,184.1**	$ 1,136.8	**$ (133.0)**	$ (4.7)
Prior service costs (credits)	**4.9**	7.5	**(100.0)**	(111.8)
Total	**$ 1,189.0**	$ 1,144.3	**$ (233.0)**	$ (116.5)

(1) Amounts related to the nonregulated entities are included in accumulated other comprehensive loss (income).

(2) Amounts related to the utilities and WBS are recorded as net regulatory assets or liabilities.

The following table shows the estimated amounts that will be amortized into net periodic benefit cost during 2019:

(in millions)	Pension Costs	OPEB Costs
Net actuarial loss (gain)	$ 76.1	$ (5.7)
Prior service costs (credits)	2.2	(15.4)
Total 2019 – estimated amortization	$ 78.3	$ (21.1)

The components of net periodic benefit cost (including amounts capitalized to our balance sheets) for the years ended December 31 were as follows:

	Pension Costs			OPEB Costs		
(in millions)	2018	2017	2016	2018	2017	2016
Service cost	**$ 47.1**	$ 44.6	$ 45.4	**$ 23.7**	$ 24.1	$ 26.1
Interest cost	**114.3**	121.8	130.8	**29.9**	32.9	37.0
Expected return on plan assets	**(196.5)**	(195.7)	(195.9)	**(59.5)**	(55.5)	(52.7)
Plan settlement	**1.0**	9.0	16.5	**—**	—	—
Amortization of prior service cost (credit)	**2.7**	2.9	3.4	**(15.4)**	(12.3)	(9.4)
Amortization of net actuarial loss	**94.0**	86.1	82.9	**1.0**	3.1	8.5
Net periodic benefit cost (credit)	**$ 62.6**	$ 68.7	$ 83.1	**$ (20.3)**	$ (7.7)	$ 9.5

Effective January 1, 2018, we adopted ASU 2017-07, Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, which modifies certain aspects of the accounting for employee benefit costs. Under the new guidance, only the service cost component can be included in total operating expenses. The remaining components of net periodic benefit cost are required to be presented in the income statement separately from the service cost component, outside of operating income. As required, this change was applied retrospectively to all prior periods presented. Accordingly, for the years ended December 31, 2018, 2017, and 2016, we have presented the service cost component of our retirement benefit plans in other operation and maintenance on the income statements, while presenting the non-service cost components in other income, net.

As required by ASU 2017-07, our income statements for the years ended December 31, 2017 and 2016, were retroactively restated from what was previously presented in our 2017 Annual Report on Form 10-K. The impacts to our income statements from adoption of this standard are reflected in the table below.

	Year Ended December 31, 2017			Year Ended December 31, 2016		
(in millions)	Form 10-K Income Statement	Impact of ASU 2017-07	Income Statement After Adoption	Form 10-K Income Statement	Impact of ASU 2017-07	Income Statement After Adoption
Operating expenses						
Other operation and maintenance	$ 2,047.0	$ 9.1	$ 2,056.1	$ 2,185.5	$ (14.2)	$ 2,171.3
Other expense						
Other income, net	64.6	9.1	73.7	80.8	(14.2)	66.6

In addition, under ASU 2017-07, only the service cost component of net periodic benefit cost is eligible for capitalization to property, plant, and equipment. In prior periods, a portion of all net benefit cost components was capitalized to property, plant, and equipment. As required, this amendment was applied prospectively, beginning January 1, 2018. As a result of the application of accounting principles for rate regulated entities, the non-service cost components of the net benefit cost that are no longer eligible for capitalization under this standard, but are capitalized under the regulatory framework, will be presented as regulatory assets or liabilities rather than property, plant, and equipment.

The weighted-average assumptions used to determine the benefit obligations for the plans were as follows for the years ended December 31:

	Pension		OPEB	
	2018	**2017**	**2018**	**2017**
Discount rate	**4.30%**	3.66%	**4.27%**	3.63%
Rate of compensation increase	**3.66%**	3.61%	**N/A**	N/A
Assumed medical cost trend rate (Pre 65)	**N/A**	N/A	**6.25%**	6.50%
Ultimate trend rate (Pre 65)	**N/A**	N/A	**5.00%**	5.00%
Year ultimate trend rate is reached (Pre 65)	**N/A**	N/A	**2024**	2024
Assumed medical cost trend rate (Post 65)	**N/A**	N/A	**6.01%**	6.09%
Ultimate trend rate (Post 65)	**N/A**	N/A	**5.00%**	5.00%
Year ultimate trend rate is reached (Post 65)	**N/A**	N/A	**2028**	2028

The weighted-average assumptions used to determine the net periodic benefit cost for the plans were as follows for the years ended December 31:

	Pension Costs		
	2018	**2017**	**2016**
Discount rate	**3.71%**	4.11%	4.35%
Expected return on plan assets	**7.12%**	7.11%	7.12%
Rate of compensation increase	**3.66%**	3.60%	3.75%

	OPEB Costs		
	2018	**2017**	**2016**
Discount rate	**3.63%**	4.04%	4.38%
Expected return on plan assets	**7.25%**	7.25%	7.25%
Assumed medical cost trend rate (Pre 65)	**6.50%**	7.00%	7.50%
Ultimate trend rate (Pre 65)	**5.00%**	5.00%	5.00%
Year ultimate trend rate is reached (Pre 65)	**2024**	2021	2021
Assumed medical cost trend rate (Post 65)	**6.09%**	7.00%	7.50%
Ultimate trend rate (Post 65)	**5.00%**	5.00%	5.00%
Year ultimate trend rate is reached (Post 65)	**2028**	2021	2021

We consult with our investment advisors on an annual basis to help us forecast expected long-term returns on plan assets by reviewing historical returns as well as calculating expected total trust returns using the weighted-average of long-term market returns for each of the major target asset categories utilized in the fund. For 2019, the expected return on assets assumption is 7.12% for the pension plans and 7.25% for the OPEB plans.

Assumed health care cost trend rates have a significant effect on the amounts reported by us for health care plans. For the year ended December 31, 2018, a one-percentage-point change in assumed health care cost trend rates would have had the following effects:

(in millions)	1% Increase	1% Decrease
Effect on total of service and interest cost components of net periodic postretirement health care benefit cost	$ 7.5	$ (5.9)
Effect on health care component of the accumulated postretirement benefit obligations	44.3	(37.1)

Plan Assets

Current pension trust assets and amounts which are expected to be contributed to the trusts in the future are expected to be adequate to meet pension payment obligations to current and future retirees.

The Investment Trust Policy Committee oversees investment matters related to all of our funded benefit plans. The Committee works with external actuaries and investment consultants on an on-going basis to establish and monitor investment strategies and target asset allocations. Forecasted cash flows for plan liabilities are regularly updated based on annual valuation results. Target allocations are determined utilizing projected benefit payment cash flows and risk analyses of appropriate investments. They are intended to reduce risk, provide long-term financial stability for the plans and maintain funded levels which meet long-term plan obligations while preserving sufficient liquidity for near-term benefit payments.

The legacy Wisconsin Energy Corporation pension trust target asset allocations are 35% equity investments, 55% fixed income investments, and 10% private equity and real estate investments. The legacy Integrys pension trust target asset allocation is 45% equity investments, 45% fixed income investments, and 10% private equity and real estate investments. The two legacy Wisconsin Energy Corporation OPEB trusts' target asset allocations are 50% equity investments and 50% fixed income investments, and 70% equity investments and 30% fixed income investments, respectively. The two largest legacy OPEB trusts for Integrys have target asset allocations of 45% equity investments and 55% fixed income, and 50% equity investments and 50% fixed income, respectively. Equity securities include investments in large-cap, mid-cap, and small-cap companies. Fixed income securities include corporate bonds of companies from diversified industries, mortgage and other asset backed securities, commercial paper, and United States Treasuries.

Pension and OPEB plan investments are recorded at fair value. See Note 1(n), Fair Value Measurements, for more information regarding the fair value hierarchy and the classification of fair value measurements based on the types of inputs used.

The following tables provide the fair values of our investments by asset class:

	December 31, 2018							
	Pension Plan Assets				OPEB Assets			
(in millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Asset Class								
Equity securities:								
United States Equity	$ 281.7	$ —	$ —	$ 281.7	$ 88.2	$ —	$ —	$ 88.2
International Equity	279.7	0.7	—	280.4	92.2	0.2	—	92.4
Fixed income securities: *								
United States Bonds	123.7	838.8	—	962.5	119.6	150.8	—	270.4
International Bonds	16.1	85.5	—	101.6	7.1	8.9	—	16.0
	$ 701.2	$ 925.0	$ —	$ 1,626.2	$ 307.1	$ 159.9	$ —	$ 467.0
Investments measured at net asset value				$ 1,064.6				$ 304.7
Total	$ 701.2	$ 925.0	$ —	$ 2,690.8	$ 307.1	$ 159.9	$ —	$ 771.7

* This category represents investment grade bonds of United States and foreign issuers denominated in United States dollars from diverse industries.

(in millions)	December 31, 2017 Pension Plan Assets Level 1	Level 2	Level 3	Total	OPEB Assets Level 1	Level 2	Level 3	Total
Asset Class								
Cash and cash equivalents	$ —	$ 53.6	$ —	$ 53.6	$ 19.6	$ 2.3	$ —	$ 21.9
Equity securities:								
United States Equity	345.0	0.1	—	345.1	101.0	—	—	101.0
International Equity	352.1	—	0.8	352.9	115.3	—	0.2	115.5
Fixed income securities: *								
United States Bonds	138.6	892.9	—	1,031.5	121.0	148.1	—	269.1
International Bonds	17.8	86.8	—	104.6	7.2	9.1	—	16.3
Private Equity and Real Estate	—	154.1	100.1	254.2	—	6.6	7.7	14.3
	$ 853.5	$ 1,187.5	$ 100.9	$ 2,141.9	$ 364.1	$ 166.1	$ 7.9	$ 538.1
Investments measured at net asset value				$ 824.9				$ 303.4
Total	$ 853.5	$ 1,187.5	$ 100.9	$ 2,966.8	$ 364.1	$ 166.1	$ 7.9	$ 841.5

* This category represents investment grade bonds of United States and foreign issuers denominated in United States dollars from diverse industries.

The following tables set forth a reconciliation of changes in the fair value of pension and OPEB plan assets categorized as Level 3 in the fair value hierarchy:

(in millions)	Private Equity and Real Estate Pension	OPEB	International Equity Pension	OPEB
Beginning balance at January 1, 2018	**$ 100.1**	**$ 7.7**	**$ 0.8**	**$ 0.2**
Realized and unrealized gains (losses)	**8.0**	**1.1**	**(0.1)**	**—**
Purchases	**18.3**	**1.5**	**—**	**—**
Liquidations	**(1.7)**	**(0.2)**	**—**	**—**
Transfers out of level 3	**(124.7)**	**(10.1)**	**(0.7)**	**(0.2)**
Ending balance at December 31, 2018	**$ —**	**$ —**	**$ —**	**$ —**

(in millions)	Private Equity and Real Estate Pension	OPEB	International Equity Pension	OPEB	U.S. Bonds Pension
Beginning balance at January 1, 2017	$ 14.6	$ 1.3	$ —	$ —	$ 0.8
Realized and unrealized gains (losses)	2.8	0.3	(0.2)	—	(0.8)
Purchases	55.5	3.6	1.0	0.2	—
Transfers into level 3	27.2	2.5	—	—	—
Ending balance at December 31, 2017	$ 100.1	$ 7.7	$ 0.8	$ 0.2	$ —

Cash Flows

We expect to contribute $11.9 million to the pension plans and $0.7 million to the OPEB plans in 2019, dependent upon various factors affecting us, including our liquidity position and the effects of the new Tax Legislation.

The following table shows the payments, reflecting expected future service, that we expect to make for pension and OPEB:

(in millions)	Pension Costs	OPEB Costs
2019	$ 239.0	$ 35.4
2020	233.0	39.6
2021	230.9	41.3
2022	225.7	41.6
2023	215.8	42.5
2024-2028	985.5	213.6

Savings Plans

We sponsor 401(k) savings plans which allow employees to contribute a portion of their pre-tax and/or after-tax income in accordance with plan-specified guidelines. A percentage of employee contributions are matched by us through a contribution into the employee's savings plan account, up to certain limits. The 401(k) savings plans include an Employee Stock Ownership Plan. Certain employees receive an employer retirement contribution, in which amounts are contributed to the employee's savings plan account based on the employee's wages, age, and years of service. Total costs incurred under all of these plans were $49.3 million, $47.9 million, and $44.3 million in 2018, 2017, and 2016, respectively.

NOTE 19—INVESTMENT IN TRANSMISSION AFFILIATES

We own approximately 60% of ATC, a for-profit, transmission-only company regulated by the FERC for cost of service and certain state regulatory commissions for routing and siting of transmission projects. We also own approximately 75% of ATC Holdco, a separate entity formed in December 2016 to invest in transmission-related projects outside of ATC's traditional footprint. The corporate managers for ATC and ATC Holdco each have an eleven-member board of directors. We have one representative on each board. Each member of the board has only one vote. Due to voting requirements, each individual board member has less than 10% of the voting control. The following tables provide a reconciliation of the changes in our investments in ATC and ATC Holdco:

	2018		
(in millions)	ATC	ATC Holdco	Total
Balance at January 1	**$ 1,515.8**	**$ 37.6**	**$ 1,553.4**
Add: Earnings (loss) from equity method investment	**139.6**	**(2.9)**	**136.7**
Add: Capital contributions	**48.2**	**5.3**	**53.5**
Less: Distributions	**78.2**	**—**	**78.2**
Less: Other	**0.1**	**—**	**0.1**
Balance at December 31	**$ 1,625.3**	**$ 40.0**	**$ 1,665.3**

	2017		
(in millions)	ATC	ATC Holdco	Total
Balance at January 1	$ 1,443.9	$ —	$ 1,443.9
Add: Earnings (loss) from equity method investment	166.0	(11.7)	154.3
Add: Capital contributions	60.3	49.3	109.6
Less: Distributions	154.2 *	—	154.2
Less: Other	0.2	—	0.2
Balance at December 31	$ 1,515.8	$ 37.6	$ 1,553.4

* Of this amount, $39.9 million was recorded as a receivable from ATC in other current assets at December 31, 2017.

	ATC
(in millions)	2016
Balance at January 1	$ 1,380.9
Add: Earnings from equity method investment	146.5
Add: Capital contributions	42.3
Add: Acquisition of Integrys's investment in ATC	(1.0)
Add: Equity method goodwill from the acquisition of Integrys [(1)]	10.4
Less: Distributions [(2)]	135.1
Less: Other	0.1
Balance at December 31	$ 1,443.9

(1) Represents an adjustment to the purchase price allocated to Integrys's investment in ATC in excess of the recorded value.

(2) Of this amount, $35.2 million was recorded as a receivable from ATC in other current assets at December 31, 2016.

We pay ATC for network transmission and other related services it provides. In addition, we provide a variety of operational, maintenance, and project management work for ATC, which is reimbursed by ATC. We are required to pay the cost of needed transmission infrastructure upgrades for new generation projects while the projects are under construction. ATC reimburses us for these costs when the new generation is placed in service.

The following table summarizes our significant related party transactions with ATC during the years ended December 31:

(in millions)	2018	2017	2016
Charges to ATC for services and construction	**$ 21.8**	$ 17.1	$ 18.5
Charges from ATC for network transmission services	**338.1**	349.3	357.3
Refund from ATC related to a FERC audit	**22.0**	—	—
Refund from ATC per FERC ROE order	**—**	28.3	—

As of December 31, 2018 and 2017, our balance sheets included the following receivables and payables related to ATC:

(in millions)	2018	2017
Accounts receivable		
Services provided to ATC	**$ 3.4**	$ 1.5
Other current assets		
Dividends receivable from ATC	**—**	39.9
Accounts payable		
Services received from ATC	**28.2**	31.2

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

(in millions)	2018	2017	2016
Income statement data			
Operating revenues	**$ 690.5**	$ 721.7	$ 650.8
Operating expenses	**358.7**	345.0	322.5
Other expense, net	**108.3**	104.1	95.5
Net income	**$ 223.5**	$ 272.6	$ 232.8

(in millions)	December 31, 2018	December 31, 2017
Balance sheet data		
Current assets	**$ 87.2**	$ 87.7
Noncurrent assets	**4,928.8**	4,598.9
Total assets	**$ 5,016.0**	$ 4,686.6
Current liabilities	**$ 640.0**	$ 767.2
Long-term debt	**2,014.0**	1,790.6
Other noncurrent liabilities	**295.3**	240.3
Shareholders' equity	**2,066.7**	1,888.5
Total liabilities and shareholders' equity	**$ 5,016.0**	$ 4,686.6

NOTE 20—SEGMENT INFORMATION

We use operating income to measure segment profitability and to allocate resources to our businesses. At December 31, 2018, we reported six segments, which are described below.

- The Wisconsin segment includes the electric and natural gas utility operations of WE, WG, WPS, and UMERC.
- The Illinois segment includes the natural gas utility and non-utility operations of PGL and NSG.
- The other states segment includes the natural gas utility and non-utility operations of MERC and MGU.
- The electric transmission segment includes our approximate 60% ownership interest in ATC, a for-profit, transmission-only company regulated by the FERC for cost of service and certain state regulatory commissions for routing and siting of transmission projects, and our approximate 75% ownership interest in ATC Holdco, which invests in transmission-related projects outside of ATC's traditional footprint.
- The non-utility energy infrastructure segment includes We Power, which owns and leases generating facilities to WE, Bluewater, which owns underground natural gas storage facilities in Michigan that provide approximately one-third of the current storage needs for our Wisconsin natural gas utilities, 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. See Note 2, Acquisitions, for more information on Bluewater, Bishop Hill III, and Coyote Ridge.
- The corporate and other segment includes the operations 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.

All of our operations and assets are located within the United States. The following tables show summarized financial information related to our reportable segments for the years ended December 31, 2018, 2017, and 2016.

2018 *(in millions)*	**Utility Operations**								
	Wisconsin	**Illinois**	**Other States**	**Total Utility Operations**	**Electric Transmission**	**Non-Utility Energy Infrastructure**	**Corporate and Other**	**Reconciling Eliminations**	**WEC Energy Group Consolidated**
External revenues	**$ 5,794.7**	**$1,400.0**	**$ 438.2**	**$ 7,632.9**	**$ —**	**$ 37.9**	**$ 8.7**	**$ —**	**$ 7,679.5**
Intersegment revenues	**—**	**—**	**—**	**—**	**—**	**430.5**	**—**	**(430.5)**	**—**
Other operation and maintenance	**2,076.1**	**472.3**	**101.0**	**2,649.4**	**—**	**12.6**	**1.8**	**(393.3)**	**2,270.5**
Depreciation and amortization	**546.6**	**170.3**	**24.1**	**741.0**	**—**	**75.7**	**29.1**	**—**	**845.8**
Operating income (loss)	**800.2**	**255.8**	**68.8**	**1,124.8**	**—**	**365.8**	**(22.2)**	**—**	**1,468.4**
Equity in earnings of transmission affiliates	**—**	**—**	**—**	**—**	**136.7**	**—**	**—**	**—**	**136.7**
Interest expense	**200.7**	**51.2**	**8.7**	**260.6**	**0.3**	**63.7**	**125.8**	**(5.3)**	**445.1**
Capital expenditures and asset acquisitions	**1,466.1**	**547.1**	**103.6**	**2,116.8**	**—**	**260.6**	**39.7**	**—**	**2,417.1**
Total assets *	**23,407.0**	**6,483.3**	**1,147.9**	**31,038.2**	**1,665.3**	**3,227.2**	**959.6**	**(3,414.5)**	**33,475.8**

* Total assets at December 31, 2018 reflect an elimination of $1,968.5 million for all lease activity between We Power and WE.

2017 *(in millions)*	**Utility Operations**								
	Wisconsin	**Illinois**	**Other States**	**Total Utility Operations**	**Electric Transmission**	**Non-Utility Energy Infrastructure**	**Corporate and Other**	**Reconciling Eliminations**	**WEC Energy Group Consolidated**
External revenues	$ 5,829.2	$1,355.5	$ 411.2	$ 7,595.9	$ —	$ 38.9	$ 13.7	$ —	$ 7,648.5
Intersegment revenues	—	—	—	—	—	446.3	—	(446.3)	—
Other operation and maintenance(1)	1,923.2	464.2	101.1	2,488.5	—	7.3	1.4	(441.1)	2,056.1
Depreciation and amortization	523.9	152.6	24.8	701.3	—	71.4	25.9	—	798.6
Operating income (loss)(1)	1,055.2	279.9	54.4	1,389.5	—	400.5	(13.9)	—	1,776.1
Equity in earnings of transmission affiliates	—	—	—	—	154.3	—	—	—	154.3
Interest expense	193.7	45.0	8.7	247.4	—	62.8	107.3	(1.8)	415.7
Capital expenditures	1,152.3	545.2	74.5	1,772.0	—	35.4	152.1	—	1,959.5
Total assets (2)	22,237.1	6,144.7	1,067.8	29,449.6	1,593.4	2,992.8	953.6	(3,398.9)	31,590.5

(1) Includes the retroactive restatement impacts of the implementation of ASU 2017-07. See Note 18, Employee Benefits, for more information on this new standard.

(2) Total assets at December 31, 2017 reflect an elimination of $2,038.1 million for all lease activity between We Power and WE.

2016 *(in millions)*	Utility Operations: Wisconsin	Illinois	Other States	Total Utility Operations	Electric Transmission	Non-Utility Energy Infrastructure	Corporate and Other	Reconciling Eliminations	WEC Energy Group Consolidated
External revenues	$ 5,805.4	$1,242.2	$ 376.5	$ 7,424.1	$ —	$ 24.9	$ 23.3	$ —	$ 7,472.3
Intersegment revenues	0.3	—	—	0.3	—	423.3	—	(423.6)	—
Other operation and maintenance (1)	2,034.6	463.6	108.8	2,607.0	—	4.3	(16.4)	(423.6)	2,171.3
Depreciation and amortization	496.6	134.0	21.1	651.7	—	68.3	42.6	—	762.6
Operating income (loss) (1)	1,017.8	261.1	51.2	1,330.1	—	375.6	(9.4)	—	1,696.3
Equity in earnings of transmission affiliate	—	—	—	—	146.5	—	—	—	146.5
Interest expense	180.9	38.9	8.5	228.3	—	62.1	120.9	(8.6)	402.7
Capital expenditures	910.9	293.2	59.5	1,263.6	—	62.3	97.8	—	1,423.7
Total assets (2)	21,730.7	5,714.6	995.1	28,440.4	1,476.9	2,777.1	778.0	(3,349.2)	30,123.2

(1) Includes the retroactive restatement impacts of the implementation of ASU 2017-07. See Note 18, Employee Benefits, for more information on this new standard.

(2) Total assets at December 31, 2016 reflect an elimination of $2,029.5 million for all lease activity between We Power and WE.

NOTE 21—VARIABLE INTEREST ENTITIES

The primary beneficiary of a variable interest entity must consolidate the entity's assets and liabilities. In addition, certain disclosures are required for significant interest holders in variable interest entities.

We assess our relationships with potential variable interest entities, such as our coal suppliers, natural gas suppliers, coal transporters, natural gas transporters, and other counterparties related to power purchase agreements, investments, and joint ventures. In making this assessment, we consider, along with other factors, the potential that our contracts or other arrangements provide subordinated financial support, the obligation to absorb the entity's losses, the right to receive residual returns of the entity, and the power to direct the activities that most significantly impact the entity's economic performance.

Investment in Transmission Affiliates

We own approximately 60% of ATC, a for-profit, electric transmission company regulated by the FERC and certain state regulatory commissions. We have determined that ATC is a variable interest entity but that consolidation is not required since we are not ATC's primary beneficiary. As a result of our limited voting rights, we do not have the power to direct the activities that most significantly impact ATC's economic performance. Therefore, we account for ATC as an equity method investment. The significant assets and liabilities related to ATC recorded on our balance sheets were our equity investment, distributions receivable, and accounts payable. At December 31, 2018 and 2017, our equity investment was $1,625.3 million and $1,515.8 million, respectively, which approximates our maximum exposure to loss as a result of our involvement with ATC. In addition, we had a receivable of $39.9 million recorded at December 31, 2017 for distributions from ATC. We also had $28.2 million and $31.2 million of accounts payable due to ATC at December 31, 2018 and 2017, respectively, for network transmission services.

We also own approximately 75% of ATC Holdco, a separate entity formed in December 2016 to invest in transmission-related projects outside of ATC's traditional footprint. We have determined that ATC Holdco is a variable interest entity but that consolidation is not required since we are not ATC Holdco's primary beneficiary. As a result of our limited voting rights, we do not have the power to direct the activities that most significantly impact ATC Holdco's economic performance. Therefore, we account for ATC Holdco as an equity method investment. The only significant asset or liability related to ATC Holdco recorded on our balance sheets was our equity investment of $40.0 million and $37.6 million at December 31, 2018 and 2017, respectively. Our equity investment approximates our maximum exposure to loss as a result of our involvement with ATC Holdco.

See Note 19, Investment in Transmission Affiliates, for more information.

Purchased Power Agreement

We have a purchased power agreement that represents a variable interest. This agreement is for 236 MW of firm capacity from a natural gas-fired cogeneration facility, and we account for it as a capital lease. The agreement includes no minimum energy requirements over the remaining term of approximately three years. We have examined the risks of the entity, including operations, maintenance, dispatch, financing, fuel costs, and other factors, and have determined that we are not the primary beneficiary of the entity. We do not hold an equity or debt interest in the entity, and there is no residual guarantee associated with the purchased power agreement.

We have $56.7 million of required capacity payments over the remaining term of this agreement. We believe that the required capacity payments under this contract will continue to be recoverable in rates, and our maximum exposure to loss is limited to the capacity payments under the contract.

NOTE 22—COMMITMENTS AND CONTINGENCIES

We and our subsidiaries have significant commitments and contingencies arising from our operations, including those related to unconditional purchase obligations, operating leases, environmental matters, and enforcement and litigation matters.

Unconditional Purchase Obligations

Our electric utilities have obligations to distribute and sell electricity to their customers, and our natural gas utilities have obligations to distribute and sell natural gas to their customers. The utilities expect to recover costs related to these obligations in future customer rates. In order to meet these obligations, we routinely enter into long-term purchase and sale commitments for various quantities and lengths of time.

Our non-utility energy infrastructure generation facilities have obligations to distribute and sell electricity through long-term offtake agreements with their customers for all of the energy produced. These projects also enter into related easements and other agreements associated with the generating facilities.

The following table shows our minimum future commitments related to these purchase obligations as of December 31, 2018, including those of our subsidiaries.

			Payments Due By Period					
(in millions)	Date Contracts Extend Through	Total Amounts Committed	2019	2020	2021	2022	2023	Later Years
Electric utility:								
Nuclear	2033	$ 8,764.4	$ 445.4	$ 475.1	$ 501.1	$ 531.2	$ 563.0	$ 6,248.6
Purchased power	2043	494.0	92.8	62.6	58.4	51.5	46.6	182.1
Coal supply and transportation	2024	1,123.8	348.6	228.5	177.8	182.4	185.8	0.7
Natural gas utility:								
Supply and transportation	2048	1,564.7	324.1	258.3	162.1	116.7	75.0	628.5
Non-utility energy infrastructure:								
Purchased power	2049	55.9	1.0	1.4	1.4	1.5	1.5	49.1
Total		$ 12,002.8	$ 1,211.9	$ 1,025.9	$ 900.8	$ 883.3	$ 871.9	$ 7,109.0

Operating Leases

We lease property, plant, and equipment under various terms. The operating leases generally require us to pay property taxes, insurance premiums, and maintenance costs associated with the leased property. Many of our leases contain one of the following options upon the end of the lease term: (a) purchase the property at the current fair market value, or (b) exercise a renewal option, as set forth in the lease agreement.

Rental expense attributable to operating leases was $11.7 million, $13.2 million, and $15.1 million in 2018, 2017, and 2016, respectively.

Future minimum payments under noncancelable operating leases are payable as follows:

Year Ending December 31	Payments *(in millions)*
2019	$ 8.7
2020	8.7
2021	6.8
2022	6.9
2023	7.1
Later years	48.7
Total	$ 86.9

Environmental Matters

Consistent with other companies in the energy industry, we face significant ongoing environmental compliance and remediation obligations related to current and past operations. Specific environmental issues affecting us include, but are not limited to, current and future regulation of air emissions such as SO_2, NOx, fine particulates, mercury, and GHGs; water intake and discharges; disposal of coal combustion products such as fly ash; and remediation of impacted properties, including former manufactured gas plant sites.

We have continued to pursue a proactive strategy to manage our environmental compliance obligations, including:

- the development of additional sources of renewable electric energy supply;
- the addition of improvements for water quality matters such as treatment technologies to meet regulatory discharge limits and improvements to our cooling water intake systems;
- the addition of emission control equipment to existing facilities to comply with ambient air quality standards and federal clean air rules;
- the protection of wetlands and waterways, threatened and endangered species, and cultural resources associated with utility construction projects;
- the retirement of old coal-fired power plants and conversion to modern, efficient, natural gas generation, super-critical pulverized coal generation, and/or replacement with renewable generation;
- the beneficial use of ash and other products from coal-fired and biomass generating units; and
- the remediation of former manufactured gas plant sites.

Air Quality

National Ambient Air Quality Standards – After completing its review of the 2008 ozone standard, the EPA released a final rule in October 2015, which lowered the limit for ground-level ozone, creating a more stringent standard than the 2008 NAAQS. The EPA issued final nonattainment area designations on May 1, 2018. The following counties within our service territories were designated as partial nonattainment: Door, Kenosha, Manitowoc, Northern Milwaukee/Ozaukee, and Sheboygan shorelines. The state of Wisconsin will need to develop a state implementation plan to bring these areas back into attainment. We will be required to comply with this state implementation plan no earlier than 2020. We believe we are well positioned to meet the requirements associated with the ozone standard and do not expect to incur significant costs to comply.

Mercury and Air Toxics Standards – In December 2018, the EPA proposed to revise the Supplemental Cost Finding for the mercury and air toxics standards (MATS) rule as well as the CAA required risk and technology review (RTR). The EPA was required by the Supreme Court to review both costs and benefits of complying with the MATS rule. After its review of costs, the EPA determined that it is not appropriate and necessary to regulate hazardous air pollutant emissions from power plants under Section 112 of the CAA. As a result, under the proposed rule, the emission standards and other requirements of the MATS rule first enacted in 2012 would remain in place. The EPA is not proposing to remove coal and oil fired power plants from the list of sources that are regulated under Section 112. The EPA also proposes that no revisions to MATS are warranted based on the results of the RTR. As a result, we do not expect the proposed rule to have a material impact on our financial condition or operations.

Climate Change – In 2015, the EPA issued a final rule regulating GHG emissions from existing generating units, referred to as the Clean Power Plan, 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, to be held in abeyance, which remains the case.

In December 2017, the EPA issued an advanced notice of proposed rulemaking to solicit input on whether it is appropriate to replace the CPP. Then, 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 New Source Performance Standards for GHG emissions from new, modified, and reconstructed fossil fueled power plants. The EPA determined that the best system of emission reduction (BSER) for new, modified, and reconstructed coal units is highly efficient generation that would be equivalent to supercritical steam conditions for larger units and subcritical steam conditions for smaller units. This proposed BSER would replace the determination from the 2015 rule, which identified BSER as partial carbon capture and storage.

In addition, we are evaluating our goals, and possible subsequent actions, with respect to national and international efforts to reduce future GHG emissions in order to limit future global temperature increases to less than two degrees Celsius. We are working with industry members to evaluate potential GHG reduction pathways.

We continue to evaluate opportunities and actions that preserve fuel diversity, lower costs for our customers, and contribute towards long-term GHG reductions. Our plan is to work with our industry partners, environmental groups, and the State of Wisconsin, with goals of reducing CO_2 emissions by approximately 40% and 80% below 2005 levels by 2030 and 2050, respectively. We have implemented and continue to evaluate numerous options in order to meet our CO_2 reduction goals. As a result of our generation reshaping plan, we expect to retire approximately 1,800 MW of coal generation by 2020, including PIPP, which we are required to retire by May 31, 2019. This plan included the 2018 retirement of the Pleasant Prairie power plant, the Pulliam power plant, and the jointly-owned Edgewater Unit 4 generation units. See Note 6, Property, Plant, and Equipment, for more information.

We are required to report our CO_2 equivalent emissions from our electric generating facilities under the EPA Greenhouse Gases Reporting Program. For 2017, we reported aggregated CO_2 equivalent emissions of approximately 29.2 million metric tonnes to the EPA. Based upon our preliminary analysis of the data, we estimate that we will report CO_2 equivalent emissions of approximately 26.4 million metric tonnes to the EPA for 2018. The level of CO_2 and other GHG emissions varies from year to year and is dependent on the level of electric generation and mix of fuel sources, which is determined primarily by demand, the availability of the generating units, the unit cost of fuel consumed, and how our units are dispatched by MISO.

We are also required to report CO_2 equivalent amounts related to the natural gas that our natural gas utilities distribute and sell. For 2017, we reported aggregated CO_2 equivalent emissions of approximately 26.5 million metric tonnes to the EPA. Based upon our preliminary analysis of the data, we estimate that we will report CO_2 equivalent emissions of approximately 29.5 million metric tonnes to the EPA for 2018.

Water Quality

Clean Water Act Cooling Water Intake Structure Rule – In August 2014, the EPA issued a final regulation under Section 316(b) of the Clean Water Act, that requires the location, design, construction, and capacity of cooling water intake structures at existing power plants to reflect the Best Technology Available (BTA) for minimizing adverse environmental impacts. The rule became effective in October 2014 and applies to all of our existing generating facilities with cooling water intake structures, except for the ERGS units, which were permitted under the rules governing new facilities.

The rule requires state permitting agencies to make BTA determinations, subject to EPA oversight, over the next several years as facility permits are reissued. Based on our assessment, we believe that existing technologies at our generating facilities, except for Weston Unit 2, satisfy the BTA requirements. WPS retired Pulliam Units 7 and 8 effective October 21, 2018. See Note 6, Property, Plant, and Equipment, for more information on the retirement of the Pulliam generating units. Therefore, WPS will not be required to make alterations to the existing water intake at these units. Based on the March 2018 reissued WPDES permit for Weston, the WDNR will not require physical modifications to the Weston Unit 2 intake structure to meet the BTA requirements based on low capacity use of the unit.

We have received a BTA determination by the WDNR, with EPA concurrence, for our intake modification at the VAPP. There has also been an interim BTA determination made by the WDNR as part of the March 2018 reissued WPDES permit for Weston Units 3 and 4. We expect that the WDNR will conclude, in the next permit reissuance, that the existing cooling tower systems for

Weston Units 3 and 4 are BTA. Due to the retirements of the Pleasant Prairie power plant, Pulliam Units 7 and 8, and our plans to retire PIPP, we do not believe that BTA determinations will be necessary for these units. Although we currently believe that existing technologies at PWGS and OC 5 through OC 8 satisfy the BTA requirements, final determinations will not be made until discharge permits are renewed for these units. Until that time, we cannot determine what, if any, intake structure or operational modifications will be required to meet the new BTA requirements for these units.

We also have provided information to the WDNR and the MDEQ about planned unit retirements. Following discussions with the MDEQ, in January 2019, we submitted a signed certification stating that PIPP will be retired no later than June 1, 2019. Based on this submittal, the MDEQ has authority to waive any remaining BTA requirements applicable to the PIPP units.

As a result of past capital investments completed to address 316(b) compliance at WE and WPS, we believe our fleet overall is well positioned to meet the new regulation and do not expect to incur significant costs to comply with this regulation.

Steam Electric Effluent Limitation Guidelines – The EPA's final steam electric effluent limitation guidelines (ELG) rule took effect in January 2016. This rule created new requirements for several types of power plant wastewaters. The two new requirements that affect WE and WPS relate to discharge limits for bottom ash transport water (BATW) and wet flue gas desulfurization (FGD) wastewater. Various petitions challenging the rule were consolidated and are pending in the United States Court of Appeals for the Fifth Circuit. In April 2017, the EPA issued an administrative stay of certain compliance deadlines while further reviewing the rule. In September 2017, the EPA issued a final rule (Postponement Rule) to postpone the earliest compliance date to November 1, 2020 for the BATW and wet FGD wastewater requirements. The latest ELG rule compliance date remains December 31, 2023 for any new wastewater treatment requirements contained in power plant discharge permits. This rule applies to wastewater discharges from our power plant processes in Wisconsin. Litigation over various aspects of the final ELG rule and the Postponement Rule is pending in several federal courts.

As a result of past capital investments completed to address ELG compliance at WE and WPS, we believe our fleet overall is well positioned to meet this new regulation. Our power plant facilities already have advanced wastewater treatment technologies installed that meet many of the discharge limits established by this rule. However, as currently constructed, the ELG rule will require additional wastewater treatment retrofits as well as installation of other equipment to minimize process water use. Due to completed and pending generating unit retirements, we believe the only facilities that will require bottom ash system modifications are Weston Unit 3 and Oak Creek Units 7 and 8. One wastewater treatment system modification may be required for the wet FGD discharges from the six units that make up the OCPP and ERGS. Based on preliminary engineering, the estimated rule compliance cost is approximately $70 million.

Land Quality

Manufactured Gas Plant Remediation – We have identified sites at which our utilities or a predecessor company owned or operated a manufactured gas plant or stored manufactured gas. We have also identified other sites that may have been impacted by historical manufactured gas plant activities. Our natural gas utilities are responsible for the environmental remediation of these sites, some of which are in the EPA Superfund Alternative Approach Program. We are also working with various state jurisdictions in our investigation and remediation planning. These sites are at various stages of investigation, monitoring, remediation, and closure.

In addition, we are coordinating the investigation and cleanup of some of these sites subject to the jurisdiction of the EPA under what is called a "multisite" program. This program involves prioritizing the work to be done at the sites, preparation and approval of documents common to all of the sites, and use of a consistent approach in selecting remedies. At this time, we cannot estimate future remediation costs associated with these sites beyond those described below.

The future costs for detailed site investigation, future remediation, and monitoring are dependent upon several variables including, among other things, the extent of remediation, changes in technology, and changes in regulation. Historically, our regulators have allowed us to recover incurred costs, net of insurance recoveries and recoveries from potentially responsible parties, associated with the remediation of manufactured gas plant sites. Accordingly, we have established regulatory assets for costs associated with these sites.

We have established the following regulatory assets and reserves related to manufactured gas plant sites as of December 31:

(in millions)	2018	2017
Regulatory assets	$ **687.1**	$ 676.6
Reserves for future remediation	**616.4**	617.2

Renewables, Efficiency, and Conservation

Wisconsin Legislation – In 2005, Wisconsin enacted Act 141, which established a goal that 10% of all electricity consumed in Wisconsin be generated by renewable resources by December 31, 2015. WE and WPS have achieved renewable energy percentages of 8.27% and 9.74%, respectively, and met their compliance requirements by constructing various wind parks, a biomass facility, and by also relying on renewable energy purchases. WE and WPS continue to review their renewable energy portfolios and acquire cost-effective renewables as needed to meet their requirements on an ongoing basis. The PSCW administers the renewable program related to Act 141, and each utility funds the program based on 1.2% of its annual operating revenues.

Michigan Legislation – In 2008, Michigan enacted Act 295, which required 10% of the state's electric energy to come from renewables by 2015 and energy optimization (efficiency) targets up to 1% annually by 2015. In December 2016, Michigan revised this legislation with Act 342, which requires additional renewable energy requirements beyond 2015. The revised legislation retained the 10% renewable energy portfolio requirement through 2018, increased the requirement to 12.5% for years 2019 through 2020, and increased the requirement to 15.0% for 2021. WE and UMERC were in compliance with these requirements as of December 31, 2018. The revised legislation continues to allow recovery of costs incurred to meet the standards and provides for ongoing review and revision to assure the measures taken are cost-effective. Upon the commercial operation of the new generating solution in the Upper Peninsula of Michigan and Tilden becoming a customer of UMERC, WE will no longer be subject to Michigan's renewable energy requirements. See Note 24, Regulatory Environment, for more information regarding the new natural gas-fired generation.

Enforcement and Litigation Matters

We and our subsidiaries are involved in legal and administrative proceedings before various courts and agencies with respect to matters arising in the ordinary course of business. Although we are unable to predict the outcome of these matters, management believes that appropriate reserves have been established and that final settlement of these actions will not have a material effect on our financial condition or results of operations.

Consent Decrees

Wisconsin Public Service Corporation Consent Decree – Weston and Pulliam Power Plants – In November 2009, the EPA issued an NOV to WPS, which alleged violations of the CAA's New Source Review requirements relating to certain projects completed at the Weston and Pulliam power plants from 1994 to 2009. WPS entered into a Consent Decree with the EPA resolving this NOV. This Consent Decree was entered by the United States District Court for the Eastern District of Wisconsin in March 2013.

The final Consent Decree includes:

- the installation of emission control technology, including ReACT™ on Weston 3,
- changed operating conditions,
- limitations on plant emissions,
- beneficial environmental projects totaling $6.0 million, and
- a civil penalty of $1.2 million.

The Consent Decree also contains requirements to refuel, repower, and/or retire certain Weston and Pulliam units. Effective June 1, 2015, WPS retired Weston Unit 1 and Pulliam Units 5 and 6. In May 2016, the EPA approved WPS's proposed revision to update requirements reflecting the conversion of Weston Unit 2 from coal to natural gas fuel, and also proposed revisions to the list of beneficial environmental projects required by the Consent Decree. WPS retired Pulliam Units 7 and 8 on October 21, 2018. See Note 6, Property, Plant, and Equipment, for more information about the retirement. WPS completed the mitigation projects required and received a completeness letter from the EPA in October 2018. We plan to request termination of the WPS Consent Decree during 2019.

WPS received approval from the PSCW in its 2015 rate order to defer and amortize the undepreciated book value of the retired plant related to Weston Unit 1 and Pulliam Units 5 and 6 starting June 1, 2015, and concluding by 2023. Therefore, in June 2015, WPS recorded a regulatory asset of $11.5 million for the undepreciated book value. In addition, WPS received approval from the PSCW in its rate orders to recover prudently incurred costs as a result of complying with the terms of the Consent Decree, with the exception of the civil penalty.

Joint Ownership Power Plants Consent Decree – Columbia and Edgewater – In December 2009, the EPA issued an NOV to Wisconsin Power and Light, the operator of the Columbia and Edgewater plants, and the other joint owners of these plants, including Madison Gas and Electric, WE (former co-owner of an Edgewater unit), and WPS. The NOV alleged violations of the CAA's New Source Review requirements related to certain projects completed at those plants. WPS, along with Wisconsin Power and Light, Madison Gas and Electric, and WE, entered into a Consent Decree with the EPA resolving this NOV. This Consent Decree was entered by the United States District Court for the Western District of Wisconsin in June 2013. WE paid an immaterial portion of the assessed penalty but has no further obligations under the Consent Decree.

The final Consent Decree includes:

- the installation of emission control technology, including scrubbers at the Columbia plant,
- changed operating conditions,
- limitations on plant emissions,
- beneficial environmental projects, with WPS's portion totaling $1.3 million, and
- WPS's portion of a civil penalty and legal fees totaling $0.4 million.

As a result of the continued implementation of the Consent Decree related to the jointly owned Columbia and Edgewater plants, the Edgewater 4 generating unit was retired on September 28, 2018. See Note 6, Property, Plant, and Equipment, for more information about the retirement.

NOTE 23—SUPPLEMENTAL CASH FLOW INFORMATION

	Year Ended December 31		
(in millions)	**2018**	**2017**	**2016**
Cash (paid) for interest, net of amount capitalized	**$ (441.5)**	$ (413.7)	$ (411.9)
Cash (paid) received for income taxes, net	**(16.3)**	5.2	39.7
Significant non-cash transactions:			
Accounts payable related to construction costs	**65.9**	169.2	170.1
Receivable related to corporate-owned life insurance proceeds	**7.7**	—	—
Portion of Bostco real estate holdings sale financed with note receivable *	**—**	7.0	—

* See Note 3, Dispositions, for more information on this sale.

Effective January 1, 2018, we adopted ASU 2016-18, Restricted Cash. Under this ASU, amounts generally described as restricted cash and restricted cash equivalents are included with cash and cash equivalents when reconciling the beginning-of-the period and end-of-the period total amounts shown on the statements of cash flows. As a result, we no longer present transfers between cash and cash equivalents and restricted cash and restricted cash equivalents in the statements of cash flows. Instead, changes in restricted cash are classified as either operating activities, investing activities, or financing activities.

The majority of our restricted cash consists of amounts held in the Integrys rabbi trust, which are used to fund participants' benefits under the Integrys deferred compensation plan and certain Integrys non-qualified pension plans. All assets held within the rabbi trust are restricted as they can only be withdrawn from the trust to make qualifying benefit payments.

Our statements of cash flows for the years ended December 31, 2017 and 2016 were retroactively restated from what was previously presented in our 2017 Annual Report on Form 10-K to reflect the adoption of ASU 2016-18. The impacts to our statements of cash flows from adoption of this standard are reflected in the table below.

	Year Ended December 31, 2017			Year Ended December 31, 2016		
(in millions)	2017 Form 10-K Cash Flows	Impact of ASU 2016-18	Cash Flows After Adoption	2017 Form 10-K Cash Flows	Impact of ASU 2016-18	Cash Flows After Adoption
Operating Activities						
Change in –						
Other current assets	$ (6.0)	$ (1.1)	$ (7.1)	$ 103.1	$ 0.1	$ 103.2
Other, net	(197.5)	0.1	(197.4)	(53.8)	0.2	(53.6)
Net cash provided by operating activities	2,079.6	(1.0)	2,078.6	2,103.5	0.3	2,103.8
Investing Activities						
Withdrawal of restricted cash from rabbi trust for qualifying payments	19.5	(19.5)	—	26.6	(26.6)	—
Proceeds from the sale of investments held in rabbi trust	—	8.7	8.7	—	1.7	1.7
Purchase of investments held in rabbi trust	—	(3.7)	(3.7)	—	(59.2)	(59.2)
Net cash used in investing activities	(2,239.6)	(14.5)	(2,254.1)	(1,270.1)	(84.1)	(1,354.2)
Net change in cash, cash equivalents, and restricted cash	1.4	(15.5)	(14.1)	(12.3)	(83.8)	(96.1)
Cash, cash equivalents, and restricted cash at beginning of year	37.5	35.2	72.7	49.8	119.0	168.8
Cash, cash equivalents, and restricted cash at end of year	$ 38.9	$ 19.7	$ 58.6	$ 37.5	$ 35.2	$ 72.7

The following table provides a reconciliation of cash and cash equivalents and restricted cash reported within the balance sheets to the sum of the total of the same amounts shown in the statements of cash flows at December 31:

(in millions)	2018	2017	2016
Cash and cash equivalents	**$ 84.5**	$ 38.9	$ 37.5
Restricted cash included in other current assets	**2.5**	—	0.8
Restricted cash included in other long term assets	**59.1**	19.7	34.4
Cash, cash equivalents, and restricted cash	**$ 146.1**	$ 58.6	$ 72.7

Effective January 1, 2018, we retrospectively adopted ASU 2016-15, Classification of Certain Cash Receipts and Cash Payments. There are eight main provisions of this ASU for which current GAAP either was unclear or did not include specific guidance. The adoption of this guidance had no impact on our financial statements for the years ended December 31, 2018, 2017, and 2016.

ASU 2016-15 provides an accounting policy election for classifying distributions received from equity method investments. We adopted the cumulative earnings approach for classifying distributions received in the statements of cash flows. Under the cumulative earnings approach, we compare the distributions received to cumulative equity method earnings since inception. Any distributions received up to the amount of cumulative equity earnings are considered a return on investment and classified in operating activities. Any excess distributions are considered a return of investment and classified in investing activities. We did not receive any excess distributions during the years ended December 31, 2018, 2017, and 2016.

NOTE 24—REGULATORY ENVIRONMENT

Tax Cuts and Jobs Act of 2017

In December 2017, our regulated utilities deferred for return to ratepayers, through future refunds, bill credits, riders, or reductions in other regulatory assets, the estimated tax benefit of $2,450 million related to the Tax Legislation that was signed into law in December 2017. This tax benefit resulted from the revaluation of deferred taxes. The Tax Legislation also reduced the corporate federal tax rate from a maximum of 35% to a 21% rate, effective January 1, 2018. We have received written orders from the PSCW and the MPSC addressing the refunding of certain of these tax benefits to ratepayers in Wisconsin and Michigan, respectively. The ICC has approved the VITA in Illinois, and the MPUC addressed the impacts to MERC in its 2018 rate order. See the Variable Income Tax Adjustment Rider discussion and the 2018 Minnesota Rate Case discussion below for more information. A summary of the Wisconsin and Michigan orders is outlined below.

Wisconsin

In May 2018, the PSCW issued an order regarding the benefits associated with the Tax Legislation. The PSCW order requires WE's and WPS's electric utility operations to use 80% and 40%, respectively, of the current 2018 and 2019 tax benefits to reduce certain regulatory assets. The remaining 20% and 60% at WE and WPS, respectively, is to be returned to electric customers in the form of bill credits. For our Wisconsin natural gas utility operations, the PSCW indicated that 100% of the current 2018 and 2019 tax benefits should be returned to natural gas customers in the form of bill credits. Regarding the net tax benefit associated with the revaluation of deferred taxes, amortization required in accordance with normalization accounting is to be used to reduce certain regulatory assets for our electric utilities and is being deferred at our natural gas utilities. The timing and method of returning the remaining net tax benefit associated with the revaluation of deferred taxes at our electric and natural gas utilities was not addressed and will be determined in a future rate proceeding.

Michigan

In February 2018, the MPSC issued an order requiring Michigan utilities to make three filings related to the Tax Legislation. The first of those filings, which was filed in March 2018, prospectively addressed the impact on base rates for the change in tax expense resulting from the federal tax rate reduction from 35% to 21%. UMERC and MGU proposed providing a volumetric bill credit, subject to reconciliation and true up. In May 2018, the MPSC issued orders approving settlements that resulted in volumetric bill credits for all of UMERC's and MGU's customers effective July 1, 2018.

The second filing, which was filed in July 2018, addressed the impact on base rates for the change in tax expense resulting from the federal tax rate reduction from 35% to 21% from January 1, 2018 until July 1, 2018. UMERC and MGU proposed to return the tax savings from these months to customers via volumetric bill credits over multiple months. The MPSC issued orders approving settlements in September 2018. In accordance with the settlement orders, the savings were returned to UMERC's and MGU's customers via volumetric bill credits that were in effect from October 1, 2018 through December 31, 2018.

The third filing was filed in October 2018 and addressed the remaining impacts of the Tax Legislation on base rates – most notably the re-measurement of deferred tax balances. UMERC and MGU proposed providing a volumetric bill credit, subject to reconciliation and true up, to return these remaining impacts of the Tax Legislation to customers. The MPSC has not yet issued an order with respect to this filing.

WE, which serves one retail electric customer in Michigan, has reached a settlement with that customer. That settlement was approved by the MPSC in May 2018 and addressed all base rate impacts of the Tax Legislation, which are being returned to the customer through bill credits.

Wisconsin Electric Power Company, Wisconsin Gas LLC, and Wisconsin Public Service Corporation

2018 and 2019 Rates

During April 2017, WE, WG, and WPS filed an application with the PSCW for approval of a settlement agreement they made with several of their commercial and industrial customers regarding 2018 and 2019 base rates. In September 2017, the PSCW issued an order that approved the settlement agreement, which freezes base rates through 2019 for electric, natural gas, and steam customers of WE, WG, and WPS. Based on the PSCW order, the authorized ROE for WE, WG, and WPS remains at 10.2%, 10.3%, and 10.0%, respectively, and the current capital cost structure for all of our Wisconsin utilities will remain unchanged through 2019.

In addition to freezing base rates, the settlement agreement extends and expands the electric real-time market pricing program options for large commercial and industrial customers and mitigates the continued growth of certain escrowed costs at WE during the base rate freeze period by accelerating the recognition of certain tax benefits. WE will flow through the tax benefit of its repair-related deferred tax liabilities in 2018 and 2019, to maintain certain regulatory asset balances at their December 31, 2017 levels. While WE would typically follow the normalization accounting method and utilize the tax benefits of the deferred tax liabilities in rate-making as an offset to rate base, benefiting customers over time, the federal tax code does allow for passing these tax repair-related benefits to ratepayers much sooner using the flow through accounting method. The flow through treatment of the repair-related deferred tax liabilities offsets the negative income statement impact of holding the regulatory assets level, resulting in no change to net income.

The agreement also allows WPS to extend through 2019, the deferral for the revenue requirement of ReACT™ costs above the authorized $275.0 million level, and other deferrals related to WPS's electric real-time market pricing program and network transmission expenses. The total cost of the ReACT™ project, excluding $51 million of AFUDC, was $342 million.

Pursuant to the settlement agreement, WPS also agreed to adopt, beginning in 2018, the earnings sharing mechanism that has been in place for WE and WG since January 2016, and all three utilities agreed to keep the mechanism in place through 2019. Under this earnings sharing mechanism, if WE, WG, or WPS earns above its authorized ROE, 50% of the first 50 basis points of additional utility earnings must be shared with customers. All utility earnings above the first 50 basis points must also be shared with customers.

As required in the settlement agreement, WE, WG, and WPS anticipate initiating a rate proceeding with the PSCW by April 1, 2019.

Acquisition of a Wind Energy Generation Facility in Wisconsin

In October 2017, WPS, along with two other unaffiliated utilities, entered into an agreement to purchase Forward Wind Energy Center, which consists of 86 wind turbines located in Wisconsin with a total capacity of 138 MW. The FERC approved the transaction in January 2018, and the PSCW approved the transaction in March 2018. The transaction closed on April 2, 2018. See Note 2, Acquisitions, for more information.

Wisconsin Public Service Corporation Proposed Solar Generation Projects

On May 31, 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. Subject to receipt of the PSCW's approval, 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.

Natural Gas Storage Facilities in Michigan

In January 2017, we signed an agreement for the acquisition of Bluewater. Bluewater owns natural gas storage facilities in Michigan that provide approximately one-third of the current storage needs for the natural gas operations of WE, WG, and WPS. As a result of this agreement, WE, WG, and WPS filed a request with the PSCW in February 2017 for a declaratory ruling on various items associated with the storage facilities. In the filing, WE, WG, and WPS requested that the PSCW review and confirm the reasonableness and prudency of their potential long-term storage service agreements and interstate natural gas transportation contracts related to the storage facilities. WE, WG, and WPS also requested approval to amend our Affiliated Interest Agreement to ensure WBS and our other subsidiaries could provide services to the storage facilities. During June 2017, the PSCW granted, subject to various conditions, these declarations and approvals, and we acquired Bluewater on June 30, 2017. In September 2017, WE, WG, and WPS entered into the long-term service agreements for the natural gas storage, which were approved by the PSCW in November 2017. See Note 2, Acquisitions, for more information.

2016 Wisconsin Public Service Corporation Rate Order

In April 2015, WPS initiated a rate proceeding with the PSCW. In December 2015, the PSCW issued a final written order for WPS, effective January 1, 2016. The order, which reflected a 10.0% ROE and a common equity component average of 51.0%, authorized a net retail electric rate decrease of $7.9 million (-0.8%) and a net retail natural gas rate decrease of $6.2 million (-2.1%). The decrease in retail electric rates was due to lower monitored fuel costs in 2016 compared with 2015. Absent the adjustment for electric fuel costs, WPS would have realized an electric rate increase. Based on the order, the PSCW allowed WPS to escrow ATC and MISO network transmission expenses through 2016. In addition, SSR payments are escrowed until a future rate proceeding. The order directed WPS to defer as a regulatory asset or liability the differences between actual transmission expenses and those included in rates. In addition, the PSCW approved a deferral for ReACT™, which required WPS to defer the revenue requirement of ReACT™ costs above the authorized $275.0 million level through 2016. Fuel costs will continue to be monitored using a 2% tolerance window.

In March 2016, WPS requested extensions from the PSCW through 2017 for the deferral of the revenue requirement of ReACT™ costs above the authorized $275.0 million level as well as escrow accounting of ATC and MISO network transmission expenses. In April 2016, WPS also requested to extend through 2017 the previously approved deferral of the revenue requirement difference between the Real Time Market Pricing and the standard tariffed rates for any of WPS's large commercial and industrial customers who entered into a service agreement with WPS under Real Time Market Pricing prior to April 15, 2016. These requests were approved by the PSCW in June 2016.

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

Illinois Proceedings

In December 2015, the ICC ordered a series of stakeholder workshops to evaluate PGL's SMP. This ICC action did not impact PGL's ongoing work to modernize and maintain the safety of its natural gas distribution system, but it instead provided the ICC with an opportunity to analyze long-term elements of the program through the stakeholder workshops. The workshops were completed in March 2016. In July 2016, the ICC initiated a proceeding to review, among other things, the planning, reporting, and monitoring of the program, including the target end date for the program, and issued a final order in January 2018. The order did not have a significant impact on PGL's existing SMP design and execution. An appeal related to the final order was filed by the Illinois Attorney General in April 2018.

Qualifying Infrastructure Plant Rider

In July 2013, Illinois Public Act 98-0057, The Natural Gas Consumer, Safety & Reliability Act, became law. This law provides PGL with a cost recovery mechanism that allows collection, through a surcharge on customer bills, of prudently incurred costs to upgrade Illinois natural gas infrastructure. In September 2013, PGL filed with the ICC requesting the proposed rider, which was approved in January 2014.

PGL's QIP 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 February 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 PGL's QIP rider during the open reconciliation years will be deemed recoverable by the ICC.

Variable Income Tax Adjustment Rider

In April 2018, the ICC approved the VITA proposed by PGL and NSG. The VITA recovers or refunds changes in income tax expense resulting from differences in income tax rates and amortization of deferred tax excesses and deficiencies (in accordance with the Tax Legislation) from the amounts used in the last PGL and NSG rate case, effective January 25, 2018.

Minnesota Energy Resources Corporation

2018 Minnesota Rate Case

In October 2017, MERC initiated a rate proceeding with the MPUC. In November 2017, the MPUC approved an interim rate order, effective January 1, 2018, authorizing a retail natural gas rate increase of $9.5 million (3.78%). In March 2018, to reflect changes in MERC's effective tax rate as a result of the enactment of the Tax Legislation, the MPUC approved a $2.5 million reduction in interim retail natural gas rates to $7.0 million (2.81%), effective April 1, 2018. The interim rates reflect a 9.11% ROE and a common equity component average of 50.9%.

In December 2018, the MPUC issued a final written order for MERC. The order authorized a retail natural gas rate increase of $3.1 million (1.26%). The rates reflect a 9.7% ROE and a common equity component average of 50.9%. In January 2019, the Minnesota Attorney General filed a petition for reconsideration requesting the MPUC reconsider its decision to set the ROE at 9.7%. The MPUC’s order is stayed while the petition for rehearing is pending, and interim rates remain in effect. MERC’s customers will be entitled to a refund to the extent the interim rate increase exceeds the final approved rate increase.

The final order addressed the various impacts of the Tax Legislation, including the remeasurement of deferred tax balances. All of the impacts from the Tax Legislation will be included in base rates. The order also approved MERC's continued use of its decoupling mechanism for residential customers. Effective January 1, 2019, MERC's small commercial and industrial customers will no longer be included in the decoupling mechanism.

2016 Minnesota Rate Order

In September 2015, MERC initiated a rate proceeding with the MPUC. In October 2016, the MPUC issued a final written order for MERC, effective March 1, 2017. The order authorized a retail natural gas rate increase of $6.8 million (3.0%). The rates reflected a 9.11% ROE and a common equity component average of 50.32%. The order approved MERC's request to continue the use of its decoupling mechanism for another three years. The final approved rate increase was lower than the interim rates collected from customers during 2016. Therefore, we refunded $4.1 million to MERC's customers in 2017.

Michigan Gas Utilities Corporation

2016 Michigan Rate Order

In June 2015, MGU initiated a rate proceeding with the MPSC. In December 2015, the MPSC issued a final written order, effective January 1, 2016, approving a settlement agreement for MGU. The order authorized a retail natural gas rate increase of $3.4 million (2.4%), a 9.9% ROE, and a common equity component average of 52.0%. Based on the settlement agreement, MGU discontinued the use of its decoupling mechanism after December 31, 2015. In addition, since bonus depreciation was in effect in 2016, MGU established a regulatory liability for the resulting cost savings and must refund the liability in its next general rate case.

Upper Michigan Energy Resources Corporation

Formation of Upper Michigan Energy Resources Corporation

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, and UMERC became operational effective January 1, 2017. This utility holds the electric and natural gas distribution assets, previously held by WE and WPS, located in the Upper Peninsula of Michigan.

In August 2016, we entered into an agreement with Tilden under which Tilden will purchase electric power from UMERC for its iron ore mine for 20 years, contingent upon UMERC's construction of approximately 180 MW of natural gas-fired generation in the Upper Peninsula of Michigan.

In October 2017, the MPSC approved both the agreement with Tilden and UMERC's application for a certificate of necessity to begin construction of the proposed generation. The estimated cost of this project is $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. The new units are expected to begin commercial operation during the second quarter of 2019. Upon receiving the MPSC's approval, retirement of WE's PIPP generating units became probable. Pursuant to MISO's April 2018 approval of the retirement of the plant, the PIPP units are required to be retired on or before May 31, 2019. Tilden will remain a customer of WE until this new generation begins commercial operation.

NOTE 25—OTHER INCOME, NET

Total other income, net was as follows for the years 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

NOTE 26—QUARTERLY FINANCIAL INFORMATION (Unaudited)

(in millions, except per share amounts)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2018					
Operating revenues	**$ 2,286.5**	**$ 1,672.5**	**$ 1,643.7**	**$ 2,076.8**	**$ 7,679.5**
Operating income	**545.1**	**330.8**	**302.7**	**289.8**	**1,468.4**
Net income attributed to common shareholders	**390.1**	**231.0**	**233.2**	**205.0**	**1,059.3**
Earnings per share (1)					
Basic	**$ 1.24**	**$ 0.73**	**$ 0.74**	**$ 0.65**	**$ 3.36**
Diluted	**1.23**	**0.73**	**0.74**	**0.65**	**3.34**
2017					
Operating revenues	$ 2,304.5	$ 1,631.5	$ 1,657.5	$ 2,055.0	$ 7,648.5
Operating income (2)	614.7	362.2	392.2	407.0	1,776.1
Net income attributed to common shareholders	356.6	199.1	215.4	432.6	1,203.7
Earnings per share (1)					
Basic	$ 1.13	$ 0.63	$ 0.68	$ 1.37	$ 3.81
Diluted	1.12	0.63	0.68	1.36	3.79

(1) Earnings per share for the individual quarters may not total the year ended earnings per share amount because of changes to the average number of shares outstanding and changes in incremental issuable shares throughout the year.

(2) Includes the retroactive restatement impacts of the implementation of ASU 2017-07. See Note 18, Employee Benefits, for more information on this new standard.

NOTE 27—NEW ACCOUNTING PRONOUNCEMENTS

Leases

In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842), which revised the previous guidance (Topic 840) regarding accounting for leases. Revisions include requiring a lessee to recognize a lease asset and a lease liability on its balance sheet for each lease, including operating leases with an initial term greater than 12 months. In addition, required quantitative and qualitative disclosures related to lease agreements were expanded. For lessors however, accounting for leases was largely unchanged from previous provisions of GAAP.

We have finalized our inventory of leases, documented our technical accounting issues, and implemented required changes to internal controls and processes as a result of the new lease guidance. In addition, we continue to finalize the related financial disclosures that will be incorporated into our quarterly report on Form 10-Q for the quarter ended March 31, 2019.

As required, we adopted Topic 842 for interim and annual periods beginning January 1, 2019. We utilized the following practical expedients, which were available under ASU 2016-02, in our adoption of the new lease guidance.

- We did not reassess whether any expired or existing contracts were leases or contained leases.
- We did not reassess the lease classification for any expired or existing leases (that is, all leases that were classified as operating leases in accordance with Topic 840 continue to be classified as operating leases, and all leases that were classified as capital leases in accordance with Topic 840 continue to be classified as capital leases).
- We did not reassess the accounting for initial direct costs for any existing leases.

We did not elect the practical expedient allowing entities to account for the nonlease components in lease contracts as part of the single lease component to which they were related. Instead, in accordance with ASC 842-10-15-31, our policy is to account for each lease component separately from the nonlease components of the contract.

We did not elect the practical expedient to use hindsight in determining the lease term and in assessing impairment of our right-of-use assets. No impairment losses were included in the measurement of our right-of-use assets upon our adoption of Topic 842.

In January 2018, the FASB issued ASU 2018-01, Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842, which is an amendment to ASU 2016-02. Land easements (also commonly referred to as rights of way) represent the right to use, access or cross another entity's land for a specified purpose. This new guidance permits an entity to elect a transitional practical expedient, to be applied consistently, to not evaluate under Topic 842 land easements that were already in existence or had expired at the time of the entity's adoption of Topic 842. Once Topic 842 is adopted, an entity is required to apply Topic 842 prospectively to all new (or modified) land easements to determine whether the arrangement should be accounted for as a lease. We elected this practical expedient upon our adoption of Topic 842, resulting in none of our land easements being treated as leases.

In July 2018, the FASB issued ASU 2018-11, Leases (Topic 842): Targeted Improvements, which amends ASU 2016-02 and allows entities the option to initially apply Topic 842 at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption, if required. We used the optional transition method to apply the new guidance as of January 1, 2019, rather than as of the earliest period presented.

While we are still refining our estimates, we expect that the right of use asset and related lease liability that we will record related to our operating leases will be in the range of $40 million to $60 million. Regarding our capital lease, while the adoption of Topic 842 changed the classification of expense related to this lease on a prospective basis, it had no impact on the total amount of lease expense recorded, and did not impact the capital lease asset and related liability amounts recorded on our balance sheets. Prior to January 1, 2019, all lease expense related to our capital lease, which relates to a long-term power purchase commitment, was recorded in cost of sales, as a component of operating income. Subsequent to our adoption of Topic 842, lease expense related to this capital lease is divided between depreciation and amortization and interest expense, as required by the new guidance. We did not require a cumulative-effect adjustment upon adoption of Topic 842, and the new guidance is not expected to have any impact on future net income or cash flows.

Financial Instruments Credit Losses

In June 2016, the FASB issued ASU 2016-13, Measurement of Credit Losses on Financial Instruments. This guidance is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019. This ASU introduces a new impairment model known as the current expected credit loss model. The ASU requires a financial asset measured at amortized cost to be presented at the net amount expected to be collected. Previously, recognition of the full amount of credit losses was generally delayed until the loss was probable of occurring. We are currently assessing the effects this guidance may have on our financial statements.

Cloud Computing

In August 2018, the FASB issued ASU 2018-15, Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract. The standard allows entities who are customers in hosting arrangements that are service contracts to apply the existing internal-use software guidance to determine which implementation costs to capitalize as an asset related to the service contract and which costs to expense. The guidance specifies classification for capitalizing implementation costs and related amortization expense within the financial statements and requires additional disclosures. The guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2019. Early adoption is permitted and can be applied either retrospectively or prospectively. We are currently evaluating the transition methods and the impact the adoption of this standard may have on our consolidated financial statements.

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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 (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.

Deloitte & Touche LLP

February 26, 2019

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

Deloitte.

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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 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 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 financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's 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.

Deloitte & Touche LLP

February 26, 2019

INTERNAL CONTROL OVER FINANCIAL REPORTING

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our and our subsidiaries' internal control over financial reporting based on the framework in *Internal Control – Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation, our management concluded that our and our subsidiaries' internal control over financial reporting was effective as of December 31, 2018.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of the effectiveness of internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

For Deloitte & Touche LLP's Report of Independent Registered Public Accounting Firm, attesting to the effectiveness of our internal controls over financial reporting, see Page F-98.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

During 2018, we completed an enterprise resource planning (ERP) system integration project to bring all of our subsidiaries onto a consolidated ERP system. Accordingly, we are modifying the design and documentation of certain internal control processes and procedures related to the integrated ERP system. We do not believe that the implementation of the ERP system will have an adverse effect on our internal control over financial reporting.

With the exception of the ERP system implementation described above, there were no changes in our internal control over financial reporting (as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) during the fourth quarter of 2018 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

WEC ENERGY GROUP, INC.
COMPARATIVE SELECTED 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.

PERFORMANCE GRAPH

The performance graph below shows a comparison of the cumulative total return, assuming reinvestment of dividends, over the last five years had $100 been invested at the close of business on December 31, 2013, in each of:

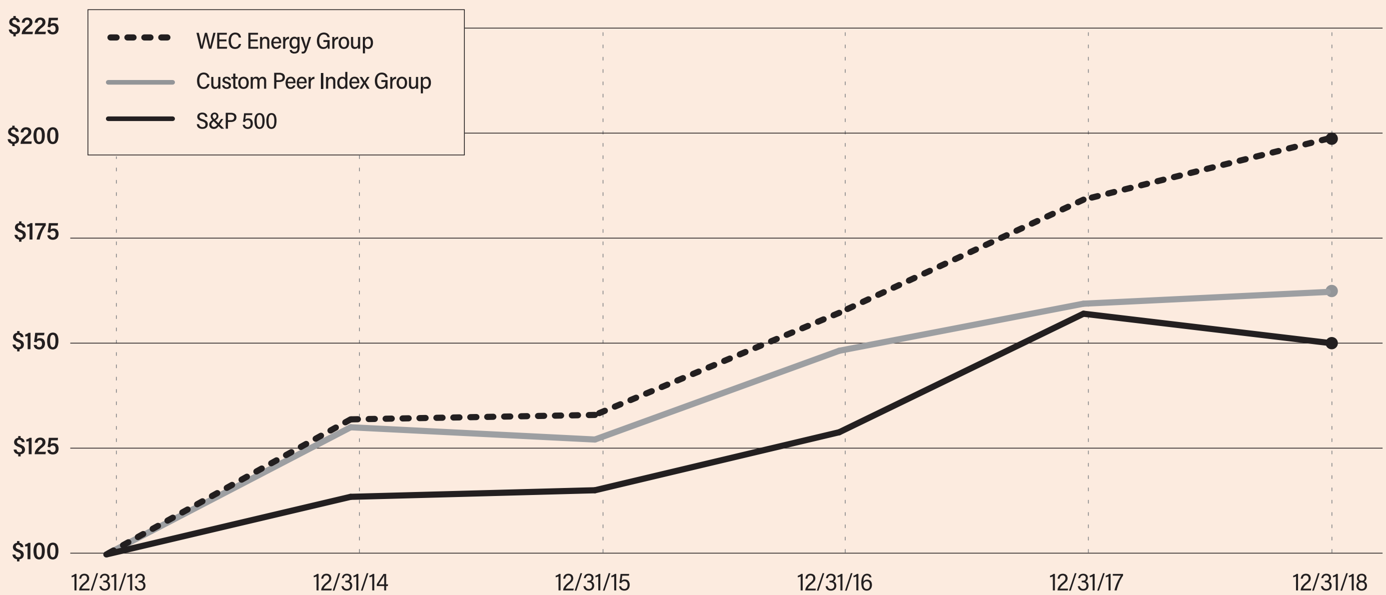
- WEC Energy Group common stock;
- a Custom Peer Group Index; and
- the Standard & Poor's 500 Index ("S&P 500").

Custom Peer Group Index. We have used the Custom Peer Group Index for peer comparison purposes because we believe the Index provided an accurate representation of our peers. The Custom Peer Group Index is a market capitalization-weighted index of companies, including WEC Energy Group, that are similar to us in terms of size and business model.

In addition to WEC Energy Group, the companies in the Custom Peer Group Index are: Alliant Energy Corporation; Ameren Corporation; American Electric Power Company, Inc.; CMS Energy Corporation; Consolidated Edison, Inc.; DTE Energy Company; Duke Energy Corp.; Edison International; Evergy, Inc.; Eversource Energy; FirstEnergy Corp.; NiSource Inc.; OGE Energy Corp.; PG&E Corporation; Pinnacle West Capital Corporation; SCANA Corporation; The Southern Company; and Xcel Energy Inc.

On June 4, 2018, Great Plains Energy, Inc. completed its merger with Westar Energy, Inc. to form the new holding company Evergy, Inc. Great Plains Energy has been included in the Custom Peer Group Index for the past several years, and is now superseded by Evergy. Accordingly, the Five-Year Cumulative Return for the Custom Peer Group Index was calculated using Great Plains Energy's performance through June 4, 2018, and Evergy's performance thereafter.

Five-Year Cumulative Return



Value of Investment at Year-End

	12/31/13	12/31/14	12/31/15	12/31/16	12/31/17	12/31/18
WEC Energy Group, Inc.	$100	$132.08	$133.13	$157.38	$184.26	$198.74
Custom Peer Group Index	$100	$130.20	$127.29	$148.37	$159.55	$162.34
S&P 500	$100	$113.68	$115.24	$129.02	$157.17	$150.27

MARKET FOR OUR COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

NUMBER OF COMMON STOCKHOLDERS

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.

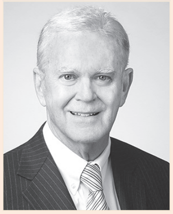
COMMON STOCK LISTING AND TRADING

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.

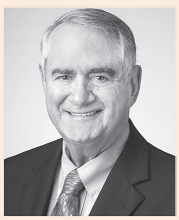
BOARD OF DIRECTORS



John F. Bergstrom
Director since 1987.
Chairman and Chief Executive Officer of Bergstrom Corporation, which owns and operates numerous automobile sales and leasing companies.

Barbara L. Bowles
Director since 1998.
Retired Vice Chair of Profit Investment Management and Retired Chairman of The Kenwood Group, Inc., investment advisory firms. The Kenwood Group, Inc. was merged into Profit Investment Management in 2006.

William J. Brodsky
Director since 2015.
Chairman of Cedar Street Asset Management LLC, a Chicago-based portfolio management firm that specializes in investments in international equities.



Albert J. Budney, Jr.
Director since 2015.
Retired President and Director of Niagara Mohawk Holdings, Inc., a holding company whose subsidiaries distribute electricity in New York.

Patricia W. Chadwick
Director since 2006.
President of Ravengate Partners, LLC, which provides businesses and not-for-profit institutions with advice about the financial markets, business management, and global economics.

Curt S. Culver
Director since 2004.
Non-Executive Chairman of the Board of MGIC Investment Corporation and Mortgage Guaranty Insurance Corporation, a private mortgage insurance company.

Danny L. Cunningham
Director since 2018.
Retired Partner and Chief Risk Officer of Deloitte & Touche LLP, an industry-leading audit, consulting, tax, and advisory firm.

William M. Farrow III
Director since 2018.
Chairman and Chief Executive Officer of Winston and Wolfe LLC, a privately held technology development and advisory company.

Thomas J. Fischer
Director since 2005.
Principal of Fischer Financial Consulting LLC, which provides consulting on corporate financial, accounting, and governance matters.

J. Kevin Fletcher
Director since 2019.
President and Chief Executive Officer of WEC Energy Group, Inc.

Gale E. Klappa
Director since 2003.
Executive Chairman of the Board of WEC Energy Group, Inc.

Henry W. Knueppel
Director since 2013.
Retired Chairman and Chief Executive Officer of Regal Beloit Corporation, a leading manufacturer of electric motors, mechanical and electrical motion controls, and power generation products.

Allen L. Leverett
Director since 2016.
Former President and Chief Executive Officer of WEC Energy Group, Inc.

Ulice Payne, Jr.
Director since 2003.
Managing Member of Addison-Clifton, LLC, which provides global trade compliance advisory services.

Mary Ellen Stanek
Director since 2012.
Managing Director and Director of Asset Management of Baird Financial Group; Chief Investment Officer, Baird Advisors; President, Baird Funds, Inc. Baird Financial Group provides wealth management, capital markets, private equity, and asset management services to clients worldwide.

OFFICERS

The names and positions as of December 31, 2018 of WEC Energy Group's officers are listed below.

Gale E. Klappa [1] [2] - Chairman of the Board and Chief Executive Officer.

J. Kevin Fletcher [1] [3] - President.

Frederick D. Kuester [1] - Senior Executive Vice President.

Robert M. Garvin [1] - Executive Vice President-External Affairs.

Margaret C. Kelsey [1] - Executive Vice President, General Counsel and Corporate Secretary.

Scott J. Lauber [1] [4] - Executive Vice President, Chief Financial Officer and Treasurer.

M. Beth Straka [1] - Senior Vice President-Corporate Communications and Investor Relations.

Darnell K. DeMasters - Vice President-Federal Government Affairs.

William J. Guc [1] - Vice President and Controller.

James A. Schubilske - Vice President and Chief Audit Officer.

Keith H. Ecke - Assistant Corporate Secretary.

David L. Hughes - Assistant Treasurer.

(1) Executive Officer of WEC Energy Group as of December 31, 2018.

(2) Effective February 1, 2019, Mr. Klappa was appointed Executive Chairman of WEC Energy Group.

(3) Effective February 1, 2019, Mr. Fletcher was appointed President and Chief Executive Officer and a Director of WEC Energy Group.

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

The following individuals were also executive officers of WEC Energy Group as of December 31, 2018:

- Charles R. Matthews - President of Peoples Energy, LLC, and President and Chief Executive Officer of The Peoples Gas Light and Coke Company and North Shore Gas Company.
- Tom Metcalfe - President of Wisconsin Electric Power Company, Wisconsin Gas LLC and Wisconsin Public Service Corporation.

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Stockholder Information

Account information

Visit **www.computershare.com/investor**.
WEC Energy Group's transfer agent, Computershare, provides our registered stockholders with secure account access. Stockholders can view share balances, market value, tax documents and account statements; review answers to frequently asked questions; perform many transactions; and sign up for eDelivery, the paperless communication program. eDelivery also provides electronic delivery of annual meeting materials.

- Write to:
  WEC Energy Group
  c/o Computershare
  P.O. Box 505000
  Louisville, KY 40233-5000

- If sending overnight correspondence, mail to:
  WEC Energy Group
  c/o Computershare
  462 South 4th St. - Suite 1600
  Louisville, KY 40202

- Call Computershare at 800-558-9663. Service representatives are available from 7 a.m. to 7 p.m. Central time on business days. An automated voice-response system also provides information 24 hours a day, seven days a week.

Securities analysts and institutional investors may contact our Investor Relations Line at **414-221-2592**. Stockholders who hold WEC Energy Group stock in brokerage accounts should contact their brokerage firm for account information.

Stock purchase plan

WEC Energy Group's Stock Plus Investment Plan provides a convenient way to purchase our common stock and reinvest dividends. To review the prospectus and enroll, go to **wecenergygroup.com** and select the Investors tab. You also may contact Computershare at **800-558-9663** to request an enrollment package. This is not an offer to sell, or a solicitation of an offer to buy, any securities. Any stock offering will be made only by prospectus.

Dividends

Dividends, as declared by the board of directors, typically are payable on the first day of March, June, September and December. Stockholders may have their dividends deposited directly into their bank accounts. Contact Computershare to request an authorization form.

Internet access helps reduce costs

You may access **wecenergygroup.com** for the latest information about the company. The site provides access to financial, corporate governance and other information, including Securities and Exchange Commission reports.

Annual certifications

WEC Energy Group has filed the required certifications of its Chief Executive Officer and Chief Financial Officer under the Sarbanes-Oxley Act regarding the quality of its public disclosures. These exhibits can be found in the company's Form 10-K for the year ended Dec. 31, 2018. The certification of WEC Energy Group's Chief Executive Officer regarding compliance with the New York Stock Exchange (NYSE) corporate governance listing standards will be filed with the NYSE following the 2019 Annual Meeting of Stockholders. Last year, we filed this certification on May 24, 2018.

Corporate Responsibility

WEC Energy Group is committed to sustainable business practices and supporting the communities we serve across the Midwest. For more information, review our Corporate Responsibility Report.

www.wecenergygroup.com/csr

WEC Energy Group

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