WEC Energy Group, Inc.
231 W. Michigan St.
Milwaukee, WI 53203

April 30, 2019

Ms. Kavita Kale
Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Hwy
Lansing, Michigan 48917

RE: Annual Reports for Michigan Code of Conduct
Wisconsin Electric Power Company d/b/a We Energies, Upper Michigan Energy Resources Corporation, and Michigan Gas Utilities Corporation

Dear Ms. Kale:

The enclosed information is transmitted in accordance with the Code of Conduct Annual Report requirements related to MPSC Orders in Case No. U-12134. This information is being transmitted on behalf of our Executive Vice President, General Counsel and Corporate Secretary, Margaret C. Kelsey. Also enclosed is a copy of our most recent organizational chart.

Please note this transmittal includes information for Wisconsin Electric Power Company, Upper Michigan Energy Resources Corporation, and Michigan Gas Utilities Corporation.

If you should have any questions regarding this transmittal, please contact me at catherine.phillips@wecenergygroup.com or (414)-221-3479.

Sincerely,

/S/ CATHERINE PHILLIPS

Catherine Phillips
Attorney

Enclosures

INTEGRYS HOLDING, INC.

FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2018

INTEGRYS HOLDING, INC.
FINANCIAL STATEMENTS
For the Year Ended December 31, 2018
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GLOSSARY OF TERMS AND ABBREVIATIONS

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

Subsidiaries and Affiliates	
ATC	American Transmission Company LLC
Bluewater	Bluewater Natural Gas Holding, LLC
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
WBS	WEC Business Services LLC
WE	Wisconsin Electric Power Company
WEC Energy Group	WEC Energy Group, Inc.
WG	Wisconsin Gas LLC
WPS	Wisconsin Public Service Corporation
WPSI	WPS Investments, LLC
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
MPSC	Michigan Public Service Commission
MPUC	Minnesota Public Utilities Commission
PSCW	Public Service Commission of Wisconsin
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	
CAA	Clean Air Act
CO_2	Carbon Dioxide
CPP	Clean Power Plan
GHG	Greenhouse Gas
NOV	Notice of Violation
WPDES	Wisconsin Pollutant Discharge Elimination System

Measurements

Dth	Dekatherm
MW	Megawatt
MWh	Megawatt-hour

Other Terms and Abbreviations

AIA	Affiliated Interest Agreement
CNG	Compressed Natural Gas
Compensation Committee	Compensation Committee of the Board of Directors of WEC Energy Group, Inc.
D.C. Circuit Court of Appeals	United States Court of Appeals for the District of Columbia Circuit
FTR	Financial Transmission Right
MISO	Midcontinent Independent System Operator, Inc.
MISO Energy Markets	MISO Energy and Operating Reserves Market
QIP	Qualifying Infrastructure Plant
ROE	Return on Equity
SMP	Natural Gas System Modernization Program
Supreme Court	United States Supreme Court
Tax Legislation	Tax Cuts and Jobs Act of 2017
VITA	Variable Income Tax Adjustment Rider

FINANCIAL STATEMENTS AND NOTES

A. INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Shareholder of Integrys Holding, Inc.:

Milwaukee, Wisconsin

We have audited the accompanying consolidated financial statements of Integrys Holding, Inc. and its subsidiaries (the "Company"), which comprise the consolidated balance sheets and the consolidated statements of capitalization as of December 31, 2018 and 2017, and the related consolidated income statements, consolidated statements of comprehensive income, consolidated statements of equity, and consolidated statements of cash flows for the three years ended December 31, 2018, and the related notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor’s judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Integrys Holding, Inc. and its subsidiaries as of December 31, 2018 and 2017, and the results of their operations and their cash flows for the three years ended December 31, 2018, in accordance with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
March 26, 2019

INTEGRYS HOLDING, INC.

B. CONSOLIDATED INCOME STATEMENTS

Year Ended December 31 *(in millions)*	2018	2017	2016
Operating revenues	**$ 3,344.7**	$ 3,264.9	$ 3,088.9
Operating expenses			
Cost of sales	**1,315.4**	1,228.1	1,080.7
Other operation and maintenance	**1,028.4**	1,016.0	1,138.0
Depreciation and amortization	**338.7**	320.3	283.5
Property and revenue taxes	**72.3**	75.1	71.8
Total operating expenses	**2,754.8**	2,639.5	2,574.0
Operating income	**589.9**	625.4	514.9
Equity in earnings of transmission affiliate	**—**	93.8	82.2
Other income, net	**29.6**	36.7	33.2
Interest expense	**150.8**	144.0	134.2
Other expense	**(121.2)**	(13.5)	(18.8)
Income before income taxes	**468.7**	611.9	496.1
Income tax expense	**123.4**	221.5	196.7
Net income attributed to common shareholder	**$ 345.3**	$ 390.4	$ 299.4

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

INTEGRYS HOLDING, INC.

C. CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31 *(in millions)*	2018	2017	2016
Net income	**$ 345.3**	$ 390.4	$ 299.4
Other comprehensive income (loss), net of tax			
Derivatives accounted for as cash flow hedges			
Reclassification of net losses to net income, net of tax	**0.6**	0.5	0.6
Cumulative effect adjustment from adoption of ASU 2018-02	**(0.2)**	—	—
Cash flow hedges, net	**0.4**	0.5	0.6
Defined benefit plans			
Pension and OPEB adjustments arising during the period, net of tax	**(2.2)**	1.0	0.2
Amortization of pension and OPEB costs included in net periodic benefit cost, net of tax of $2.0, $3.0, and $2.9, respectively	**5.1**	4.3	4.3
Cumulative effect adjustment from adoption of ASU 2018-02	**(3.0)**	—	—
Defined benefit plans, net	**(0.1)**	5.3	4.5
Other comprehensive income, net of tax	**0.3**	5.8	5.1
Comprehensive income attributed to common shareholder	**$ 345.6**	$ 396.2	$ 304.5

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

INTEGRYS HOLDING, INC.

D. CONSOLIDATED BALANCE SHEETS

At December 31 *(in millions, except share and per share data)*	2018	2017
Assets		
Current assets		
Cash and cash equivalents	**$ 24.7**	$ 19.3
Accounts receivable and unbilled revenues, net of reserves of $89.6 and $84.8, respectively	**665.0**	668.1
Receivables from related parties	**59.3**	15.6
Materials, supplies, and inventories	**244.2**	238.0
Notes receivable from related party	**139.5**	278.2
Prepaid taxes	**41.5**	57.5
Other	**78.6**	57.6
Current assets	**1,252.8**	1,334.3
Long-term assets		
Property, plant, and equipment, net of accumulated depreciation of $3,541.8 and $3,442.5, respectively	**9,128.8**	8,460.4
Regulatory assets	**1,466.7**	1,385.7
Equity investment in transmission affiliate	**—**	621.1
Goodwill	**635.8**	635.8
Other	**361.5**	333.5
Long-term assets	**11,592.8**	11,436.5
Total assets	**$ 12,845.6**	$ 12,770.8
Liabilities and Equity		
Current liabilities		
Short-term debt	**$ 479.5**	$ 533.0
Current portion of long-term debt	**75.0**	255.0
Accounts payable	**479.7**	435.4
Payables to related parties	**109.8**	66.2
Accrued taxes	**63.0**	107.9
Customer credit balances	**87.6**	79.6
Other	**160.0**	163.6
Current liabilities	**1,454.6**	1,640.7
Long-term liabilities		
Long-term debt	**3,402.7**	2,994.6
Deferred income taxes	**1,129.9**	1,146.9
Deferred investment tax credits	**55.9**	57.8
Regulatory liabilities	**1,540.2**	1,479.2
Environmental remediation liabilities	**525.4**	557.7
Pension and OPEB obligations	**188.2**	209.8
AROs	**381.5**	501.7
Other	**177.6**	178.2
Long-term liabilities	**7,401.4**	7,125.9
Commitments and contingencies (Note 22)		
Common stock – $0.01 par value; 10,000 shares authorized, 1,020 shares issued and outstanding	**—**	—
Additional paid in capital	**2,301.5**	2,664.9
Retained earnings	**1,705.3**	1,356.8
Accumulated other comprehensive loss	**(17.2)**	(17.5)
Total common shareholder's equity	**3,989.6**	4,004.2
Total liabilities and equity	**$ 12,845.6**	$ 12,770.8

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

INTEGRYS HOLDING, INC.

E. CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31 *(in millions)*	2018	2017	2016
Operating activities			
Net income	**$ 345.3**	$ 390.4	$ 299.4
Reconciliation to cash provided by operating activities			
Depreciation and amortization	**338.7**	320.3	283.5
Deferred income taxes and investment tax credits, net	**144.2**	237.5	257.0
Contributions and payments related to pension and OPEB plans	**(61.1)**	(70.2)	(2.4)
Equity income in transmission affiliate, net of distributions	**—**	(9.3)	(26.0)
Cash paid for benefit-related transfers with WBS	**(0.3)**	(36.7)	(31.2)
Change in –			
Accounts receivable and unbilled revenues	**(70.2)**	(34.1)	(124.3)
Materials, supplies, and inventories	**(5.9)**	32.7	58.9
Prepaid taxes	**15.9**	(5.8)	70.5
Other current assets	**31.0**	5.3	1.6
Accounts payable	**160.5**	(10.3)	(8.6)
Accrued taxes	**(34.0)**	44.3	25.1
Other current liabilities	**3.6**	37.2	(21.6)
Other, net	**46.9**	(73.3)	22.7
Net cash provided by operating activities	**914.6**	828.0	804.6
Investing activities			
Capital expenditures	**(1,092.2)**	(960.0)	(665.6)
Acquisition of Forward Wind Energy Center	**(77.1)**	—	—
Proceeds from the sale of assets and businesses	**4.5**	4.3	99.7
Proceeds from assets transferred to WBS	**0.1**	25.5	7.6
Payments for assets transferred from WBS	**(70.6)**	(46.1)	(95.0)
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)
Short-term notes receivable from related parties, net	**138.7**	(278.2)	14.8
Capital contributions to transmission affiliate	**—**	(34.1)	(23.9)
Other, net	**(0.8)**	3.5	(2.6)
Net cash used in investing activities	**(1,043.8)**	(1,280.1)	(722.5)
Financing activities			
Issuance of common stock to parent	**—**	—	66.4
Retirement of long-term debt	**(369.9)**	(125.0)	(278.6)
Issuance of long-term debt	**600.0**	310.0	200.0
Repayment of loan	**—**	—	(28.6)
Change in short-term debt	**(53.5)**	305.0	(77.5)
Short-term debt to related parties, net	**—**	(42.0)	(53.1)
Other, net	**(4.4)**	(4.1)	(1.9)
Net cash provided by (used in) financing activities	**172.2**	443.9	(173.3)
Net change in cash, cash equivalents, and restricted cash	**43.0**	(8.2)	(91.2)
Cash, cash equivalents, and restricted cash at beginning of year	**39.0**	47.2	138.4
Cash, cash equivalents, and restricted cash at end of year	**$ 82.0**	$ 39.0	$ 47.2

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

INTEGRYS HOLDING, INC.

F. CONSOLIDATED STATEMENTS OF EQUITY

(in millions, except per share data)	Common Stock	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Shareholder's Equity
Balance at December 31, 2015	$ —	$ 2,691.7	$ 667.0	$ (28.4)	$ 3,330.3
Net income attributed to common shareholder	—	—	299.4	—	299.4
Other comprehensive income	—	—	—	5.1	5.1
Issuance of common stock to parent	—	66.4	—	—	66.4
Transfer of our ownership in WBS to WEC Energy Group	—	(73.0)	—	—	(73.0)
Other	—	0.2	—	—	0.2
Balance at December 31, 2016	$ —	$ 2,685.3	$ 966.4	$ (23.3)	$ 3,628.4
Net income attributed to common shareholder	—	—	390.4	—	390.4
Other comprehensive income	—	—	—	5.8	5.8
Transfer of net assets to UMERC	—	(20.6)	—	—	(20.6)
Other	—	0.2	—	—	0.2
Balance at December 31, 2017	**$ —**	**$ 2,664.9**	**$ 1,356.8**	**$ (17.5)**	**$ 4,004.2**
Net income attributed to common shareholder	**—**	**—**	**345.3**	**—**	**345.3**
Other comprehensive income	**—**	**—**	**—**	**3.5**	**3.5**
Transfer of WPSI's ownership interest in ATC and related taxes	**—**	**(363.4)**	**—**	**—**	**(363.4)**
Cumulative effect adjustment from ASU 2018-02 adoption	**—**	**—**	**3.2**	**(3.2)**	**—**
Balance at December 31, 2018	**$ —**	**$ 2,301.5**	**$ 1,705.3**	**$ (17.2)**	**$ 3,989.6**

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

INTEGRYS HOLDING, INC.

G. CONSOLIDATED STATEMENTS OF CAPITALIZATION

At December 31 *(in millions)*			2018	2017
Common shareholder's equity (see accompanying statement)			**$ 3,989.6**	$ 4,004.2
Long-term debt	**Interest Rate**	**Year Due**		
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
PGL First and Refunding Mortgage Bonds (secured) [1]	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) [2]	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
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
Total			**3,512.0**	3,281.9
Unamortized debt issuance costs			**(33.6)**	(31.7)
Unamortized discount, net and other			**(0.7)**	(0.6)
Total long-term debt, including current portion			**3,477.7**	3,249.6
Current portion of long-term debt			**(75.0)**	(255.0)
Total long-term debt			**3,402.7**	2,994.6
Total long-term capitalization			**$ 7,392.3**	$ 6,998.8

[1] 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.

[2] 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.

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

H. NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2018

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Nature of Operations—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. In this report, when we refer to "us," "we," "our," or "ours," we are referring to Integrys Holding, Inc. (Integrys).

We are a wholly owned subsidiary of WEC Energy Group. Our financial statements include the accounts of Integrys, a diversified energy holding company, and the accounts of our subsidiaries in the following reportable segments:

- Wisconsin segment – Consists of WPS, which is engaged primarily in the generation of electricity and the distribution of electricity and natural gas in Wisconsin. WPS's electric and natural gas operations in the state of Michigan were also included in this segment prior to their transfer 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 – Consisted of our approximate 34% ownership interest in ATC, a for-profit, electric transmission company regulated by the FERC and certain state regulatory commissions, through December 31, 2017. In January 2018, we transferred our ownership in WPSI, which held our ownership interest in ATC, to another subsidiary of WEC Energy Group.

- Corporate and other segment – Consists of the Integrys holding company, the PELLC holding company, PDL, and ITF. During 2016, we completed the sale of ITF, and PDL sold both its natural gas-fired cogeneration facility and its landfill gas facility. In 2018, PDL also sold three of its distributed commercial and industrial solar projects. These PDL facilities were not significant to our operations. Effective January 1, 2016, we transferred our ownership in WBS to WEC Energy Group. This transaction was a non-cash equity transfer between entities under common control and, therefore, did not result in the recognition of a gain or loss. See Note 3, Disposition, for more information on the sale of ITF.

In December 2016, both the MPSC and the PSCW approved the operation of UMERC as a stand-alone utility owned by WEC Energy Group 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 WPS, and the electric assets previously held by WE, located in the Upper Peninsula of Michigan. UMERC currently meets its market obligations through power purchase agreements with WPS and WE. UMERC will begin to generate electricity when its new generation solution in the Upper Peninsula of Michigan begins commercial operation, which is expected to occur on March 31, 2019. See Note 4, Related Parties, for more information on UMERC.

Our financial statements also reflect our proportionate interests in certain jointly owned utility facilities. See Note 8, 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 5, 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, our performance obligation is bundled to consist of both the sale and the delivery of the electric commodity.

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 utility monitors the deferral of under-collected costs to ensure that it does not cause them to earn a greater ROE than authorized by the PSCW.

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 utility 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 utility 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 include riders 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

A portion of our non-utility operating revenues are 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.

Other non-utility revenues are derived from distributed renewable solar projects, which 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.

Other Operating Revenues

Alternative Revenues

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

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

- The rates of PGL, NSG, and MERC include decoupling mechanisms. These mechanisms differ by state and allow the utilities to recover or refund the differences between actual and authorized margins for certain customer classes.
- MERC's rates include a conservation improvement program rider, which includes a financial incentive for meeting energy savings goals.
- WPS provides 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	**$ 138.9**	$ 128.4
Materials and supplies	**75.5**	65.8
Fossil fuel	**29.8**	43.8
Total	**$ 244.2**	$ 238.0

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 35% and 34% 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 our 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 6, 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
WPS	**2.50%**	2.55%	2.58%
PGL	**3.25%**	3.29%	3.31%
NSG	**2.45%**	2.43%	2.44%
MERC *	**1.95%**	2.51%	2.53%
MGU	**2.61%**	2.61%	2.63%

* 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 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 us for all or a portion of expenditures for certain capital projects. Such contributions in aid of construction costs are recorded as a reduction to property, plant, and equipment.

See Note 7, Property, Plant, and Equipment, for more information.

(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 WPS. Approximately 50% of WPS's retail jurisdictional CWIP expenditures are subject to the AFUDC calculation. For 2018, WPS's average AFUDC retail rate was 7.72%, and its average AFUDC wholesale rate was 1.96%. The other utilities did not record significant AFUDC for 2018, 2017, or 2016.

Total AFUDC was as follows for the years ended December 31:

(in millions)	2018	2017	2016
AFUDC – Debt	**$ 1.9**	$ 1.6	$ 8.1
AFUDC – Equity	**4.6**	4.1	19.5

(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 10, Goodwill and Other Intangible Assets, 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 7, Property, Plant, and Equipment, for more information.

(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 9, Asset Retirement Obligations, for more information.

(k) Emission Allowances—WPS accounts for emission allowances as inventory at average cost by vintage year. Charges to income result when allowances are used in operating WPS's generation plants. These charges are included in the costs subject to the fuel window rules. Gains on sales of allowances at WPS are returned to ratepayers.

(l) Stock-Based Compensation—Our employees participate in the WEC Energy Group stock-based compensation plans. In accordance with the WEC Energy Group shareholder approved WEC Energy Group 1993 Omnibus Stock Incentive Plan, Amended and Restated Effective as of January 1, 2016, WEC Energy Group provides long-term incentives through its equity interests to its 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 WEC Energy Group common stock, cash, or a combination thereof. The number of shares of WEC Energy Group common stock authorized for issuance under the plan is 34.3 million.

Stock-based compensation expense is allocated to us based on the outstanding awards held by our employees and our allocation of labor costs. Awards classified as equity awards are measured based on their grant-date fair value. Awards classified as liability awards are recorded at fair value each reporting period. We account for forfeitures as they occur, rather than estimating potential future forfeitures and recording them over the vesting period.

Stock Options

Our employees are granted WEC Energy Group 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 the fair market value of WEC Energy Group common stock on the grant date. Historically, all stock options have been granted with an exercise price equal to the fair market value of WEC Energy Group common stock on the date of the grant. Options may not be exercised within 6 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 grant.

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

	2018	2017	2016
Stock options granted	**45,740**	46,450	52,305
Estimated weighted-average fair value per stock option	**$ 7.77**	$ 7.44	$ 5.59
Assumptions used to value the options:			
Risk-free interest rate	**1.6% – 2.5%**	0.7% – 2.5%	0.4% – 1.8%
Dividend yield	**3.5%**	3.5%	4.0%
Expected volatility	**18.0%**	19.0%	18.0%
Expected life (years)	**6.0**	6.8	7.4

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 WEC Energy Group's dividend rate at the time of the grant and historical stock prices. Expected volatility and expected life assumptions were based on WEC Energy Group's historical experience.

Restricted Shares

WEC Energy Group restricted shares granted to our employees have a three-year vesting period with one-third of the award vesting on each anniversary of the grant date. The 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 WEC Energy Group's 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. Participants may earn between 0% and 175% of the base 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 WEC Energy Group's 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 11, Common Equity, for more information on WEC Energy Group's stock-based compensation plans.

(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. We and our subsidiaries are included in WEC Energy Group's consolidated federal and state income tax returns. In accordance with our tax allocation agreement with WEC Energy Group, we are allocated income tax payments and refunds based on our separate tax computation. See Note 15, 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 increased $3.2 million as a result of adopting ASU 2018-02, primarily related to our pension and post-retirement plans. 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 16, 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 purchased power, generation, and natural gas costs for the benefit of our customers. Our approach is non-speculative and designed to mitigate risk. Our 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 17, 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 18, Guarantees, for more information.

(q) Employee Benefits—The costs of pension and OPEB plans are expensed over the periods during which employees render service. These costs are distributed among WEC Energy Group's 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 19, 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 presented as customer credit balances 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 9, 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—The geographic concentration of our customers in our service territories 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 PGL and NSG is mitigated by their rider 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.

(u) Subsequent Events—Subsequent events were evaluated for potential recognition or disclosure through March 26, 2019, which is the date the financial statements were available to be issued.

NOTE 2—ACQUISITION

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 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.

NOTE 3—DISPOSITION

Corporate and Other Segment – Sale of Integrys Transportation Fuels

In February 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 sale, as ITF's assets and liabilities were adjusted to fair value, less costs to sell in 2015. 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. We recognized income before income taxes from ITF of $5.8 million for the year ended December 31, 2016.

NOTE 4—RELATED PARTIES

We and our subsidiaries routinely enter into transactions with related parties, including WEC Energy Group, its other subsidiaries, ATC, and other affiliated entities.

We provide and receive services, property, and other items of value to and from our parent, WEC Energy Group, and other subsidiaries of WEC Energy Group.

Following our acquisition by WEC Energy Group on June 29, 2015, Integrys Business Support, LLC (IBS) changed its name to WEC Business Services LLC, and a new AIA (Non-WBS AIA) went into effect. The new Non-WBS AIA included the former Wisconsin Energy Corporation subsidiaries. It governed the provision and receipt of services by WEC Energy Group's subsidiaries, except that WBS continued to provide services to us and our subsidiaries only under the existing WBS AIAs. WBS provided services to WEC Energy

Group and the former Wisconsin Energy Corporation subsidiaries under interim WBS AIAs. The Non-WBS AIA included no other significant changes from the prior Non-IBS AIA. The PSCW and all other relevant state commissions approved the Non-WBS AIA or granted appropriate waivers related to the Non-WBS AIA.

Services under the Non-WBS AIA were subject to various pricing methodologies. All services provided by any regulated subsidiary to another regulated subsidiary were priced at cost. All services provided by any regulated subsidiary to any nonregulated subsidiary were priced at the greater of cost or fair market value. All services provided by any nonregulated subsidiary to any regulated subsidiary were priced at the lesser of cost or fair market value. All services provided by any regulated or nonregulated subsidiary to WBS were priced at cost.

WBS provided several categories of services (including financial, human resource, and administrative services) to us pursuant to the WBS AIAs, which were approved, or from which we were granted appropriate waivers, by the appropriate regulators, including the PSCW. As required by FERC regulations for centralized service companies, WBS renders services at cost. The PSCW must be notified prior to making changes to the services offered under and the allocation methods specified in the WBS AIAs. Other modifications or amendments to the WBS AIAs would require PSCW approval. Recovery of allocated costs is addressed in our rate cases.

A new AIA took effect January 1, 2017. The new agreement replaced the previous agreements. The pricing methodology and services under this new agreement are substantially identical to those under the agreements that were replaced. All of the applicable state commissions approved modifications to the new AIA to incorporate WEC Energy Group's acquisition of Bluewater. See below for more information about the Bluewater acquisition.

Effective January 1, 2016, we transferred our ownership in WBS to WEC Energy Group. This transaction was a $73.0 million non-cash equity transfer between entities under common control, and therefore, did not result in the recognition of a gain or loss.

Effective January 1, 2018, we transferred WPSI's ownership interest in ATC, and related taxes, to another subsidiary of WEC Energy Group. This transaction was a $363.4 million non-cash equity transfer between entities under common control, and therefore, did not result in the recognition of a gain or loss.

We pay ATC for 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. Services are billed to and from ATC under agreements approved by the PSCW, at each of our fully allocated costs.

WPS provides services to WRPC under an operating agreement approved by the PSCW. WPS is also under a service agreement with WRPC where it is billed for services provided by WRPC. Services are billed to and from WRPC under these agreements at a fully allocated cost.

Our balance sheets included the following receivables and payables related to transactions entered into with ATC:

(in millions)	**December 31, 2018**	**December 31, 2017**
Accounts receivable		
Services provided to ATC	**$ 1.2**	$ 0.7
Accounts payable		
Network transmission services from ATC	**8.8**	9.0

The following table shows activity associated with our related party transactions for the years ended December 31:

(in millions)	2018	2017	2016
Transactions with WE			
Natural gas sales to WE from WPS	**$ 1.9**	$ 1.6	$ 1.9
Billings to WE from WPS [1]	**10.9**	4.5	4.2
Billings from WE to WPS [1]	**17.8**	28.2	9.0
Transactions with WBS [1]			
Billings to WBS [2]	**48.2**	103.5	24.8
Billings from WBS [3]	**322.4**	457.7	377.0
Transactions with UMERC [4]			
Electric sales to UMERC from WPS	**15.8**	16.2	—
Natural gas sales to UMERC from WPS	**2.7**	2.5	—
Transactions with Bluewater [5]			
Storage service fees	**4.7**	0.3	—
Transactions related to ATC			
Charges to ATC for services and construction	**7.9**	6.2	8.6
Charges from ATC for network transmission services	**106.1**	107.8	109.4
Refund from ATC related to a FERC audit	**6.6**	—	—
Refund from ATC per FERC ROE order	**—**	8.9	—
Transactions with equity-method investees			
Rental payments to WRPC [6]	**1.3**	1.3	—
Purchases of energy from WRPC	**—**	0.5	3.7
Charges from WRPC for services	**2.4**	2.2	—
Charges to WRPC for operations	**1.2**	0.9	0.7

(1) Includes amounts billed for services, pass through costs, and other items in accordance with the approved AIAs.

(2) Includes $0.1 million and $25.5 million for the transfer of a PGL training facility to WBS for the years ended December 31, 2018 and 2017, respectively. Includes $7.6 million primarily for the transfer of certain software assets to WBS for the year ended December 31, 2016.

(3) Includes $70.6 million, $46.1 million, and $95.0 million for the transfer of certain software assets to us for the years ended December 31, 2018, 2017, and 2016, respectively. The year ended December 31, 2017, includes $36.7 million of cash paid related to pension trust assets transferred to us in conjunction with the Integrys pension plan split for the year ended December 31, 2017. Effective January 1, 2017, the Integrys Energy Group Retirement Plan was split into six separate plans. While the split did not impact our pension benefit obligation, federal regulations required a different allocation of assets among the new plans. Assets were transferred out of our plan in January 2017. See Note 19, Employee Benefits, for more information. Includes $0.3 million and $31.2 million for the transfer of certain benefit-related liabilities to WBS for the years ended December 31, 2018 and 2016, respectively.

(4) UMERC became operational effective January 1, 2017. See below for more information.

(5) WEC Energy Group's acquisition of Bluewater was completed June 30, 2017. See below for more information.

(6) In March 2017, WPS terminated its purchased power agreement with WRPC and entered into a lease agreement with WRPC to lease 50% of its hydroelectric power generation facilities.

We manage our liquidity in part by maintaining adequate financing commitments with related parties. We have the ability to borrow to and from our parent, WEC Energy Group, in amounts up to $400 million. At December 31, 2018 and 2017, we had short-term notes receivable from WEC Energy Group of $139.5 million and $278.2 million, respectively. See Note 13, Short-Term Debt and Lines of Credit, for more information.

Parent Company's Acquisition of Natural Gas Storage Facilities in Michigan

In June 2017, WEC Energy Group completed its acquisition of Bluewater for $226.0 million. Bluewater owns natural gas storage facilities in Michigan that provide a portion of the current storage needs for WPS's natural gas utility operations. In September 2017, WPS entered into a long-term service agreement with a wholly owned subsidiary of Bluewater to take a portion of the storage, which was then approved by the PSCW in November 2017. See Note 24, Regulatory Environment, for more information.

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. UMERC, a subsidiary of WEC Energy Group, became operational effective January 1, 2017, and WPS transferred customers and property, plant, and equipment as of that date. WPS transferred approximately 9,000 retail electric customers and 5,300 natural gas customers to UMERC, along with approximately 600 miles of electric distribution lines and approximately 100 miles of natural gas distribution mains. WPS also transferred related electric distribution substations in the Upper Peninsula of Michigan and all property rights for the distribution assets to UMERC. The book value of the net assets (including the related deferred income tax liabilities) transferred to UMERC from WPS in 2017, was $20.6 million. This transaction was a non-cash equity transfer recorded to additional paid in capital between entities under common control, and therefore, did not result in the recognition of a gain or loss.

UMERC obtains energy through the MISO Energy Markets and meets its market obligations through power purchase agreements with WE and WPS. UMERC will begin to generate electricity when its new generation solution in the Upper Peninsula of Michigan begins commercial operation, which is expected to occur on March 31, 2019.

NOTE 5—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 revenues and cash flows are affected by economic factors. For our segments, revenues are further disaggregated by electric and natural gas operations and then by customer class. Each customer class within our electric and natural gas operations 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	Corporate and Other	Reconciling Eliminations	Integrys Holding Consolidated
Year ended December 31, 2018							
Electric	$ 1,192.2	$ —	$ —	$ 1,192.2	$ —	$ —	$ 1,192.2
Natural gas	305.5	1,406.8	428.4	2,140.7	—	—	2,140.7
Total utility revenues	1,497.7	1,406.8	428.4	3,332.9	—	—	3,332.9
Other non-utility revenues	—	0.2	16.1	16.3	7.8	—	24.1
Total revenues from contracts with customers	1,497.7	1,407.0	444.5	3,349.2	7.8	—	3,357.0
Other operating revenues	0.8	(7.0)	(6.3)	(12.5)	0.2	—	(12.3)
Total operating revenues	$ 1,498.5	$1,400.0	$438.2	$ 3,336.7	$ 8.0	$ —	$ 3,344.7

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	$ 381.5
Small commercial and industrial	371.4
Large commercial and industrial	238.8
Other	8.5
Total retail revenues	1,000.2
Wholesale	142.3
Resale	38.5
Other utility revenues	11.2
Total electric utility operating revenues	$ 1,192.2

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	$ 177.7	$ 877.5	$ 263.3	$ 1,318.5
Commercial and industrial	107.6	266.9	140.0	514.5
Total retail revenues	285.3	1,144.4	403.3	1,833.0
Transport	19.7	244.0	31.8	295.5
Other utility revenues *	0.5	18.4	(6.7)	12.2
Total natural gas utility operating revenues	$ 305.5	$ 1,406.8	$ 428.4	$ 2,140.7

* 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
Appliance service revenues	$ 15.9
Distributed renewable solar project revenues	7.8
Other	0.4
Total other non-utility operating revenues	$ 24.1

Other Operating Revenues

Other operating revenues consist primarily of the following:

(in millions)	Year Ended December 31, 2018
Alternative revenues *	$ (41.7)
Late payment charges	28.4
Leases	1.0
Total other operating revenues	$ (12.3)

* 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 6—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]			
Environmental remediation costs [3]	**$ 577.2**	$ 598.9	22
Pension and OPEB costs [4]	**496.5**	476.2	19
AROs	**156.7**	150.7	9
Plant retirements	**78.1**	8.3	7
Income tax related items [5]	**42.2**	12.0	15
Uncollectible expense [6]	**38.7**	35.1	1(d)
Energy costs recoverable through rate adjustments [7]	**28.1**	20.3	1(d)
Termination of a tolling agreement with Fox Energy Company LLC [8]	**21.7**	27.2	
Derivatives	**16.0**	14.1	1(o)
Unamortized loss on reacquired debt [9]	**13.6**	14.6	
De Pere Energy Center [10]	**10.1**	14.0	
Crane Creek wind project production tax credits [11]	**0.4**	22.8	
Other, net	**37.8**	28.7	
Total regulatory assets	**$ 1,517.1**	$ 1,422.9	
Balance sheet presentation			
Current assets	**$ 50.4**	$ 37.2	
Regulatory assets	**1,466.7**	1,385.7	
Total regulatory assets	**$ 1,517.1**	$ 1,422.9	

[1] Based on prior and current rate treatment, we believe it is probable that our utilities will continue to recover from customers the regulatory assets in this table. In accordance with GAAP, our regulatory assets do not include the allowance for ROE that is capitalized for regulatory purposes. This allowance was $15.1 million and $14.7 million at December 31, 2018 and 2017, respectively.

[2] As of December 31, 2018, we had $117.8 million of regulatory assets not earning a return and $5.3 million of regulatory assets earning a return based on short-term interest rates. The regulatory assets not earning a return primarily relate to uncollectible expense and certain environmental remediation costs, the recovery of which depends on the timing of the actual expenditures, as well as natural gas costs recoverable through rate adjustments, 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] As of December 31, 2018, we had made cash expenditures of $51.8 million related to these environmental remediation costs. The remaining $525.4 million represents our estimated future cash expenditures.

[4] 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.

[5] For information on 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 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.

[7] Represents energy costs that will be recovered from customers in the future.

[8] Represents an early termination fee of a tolling agreement WPS had with the Fox Energy Center. Prior to the purchase of the Fox Energy Center in 2013, WPS supplied natural gas for the facility and purchased capacity and the associated energy output under the tolling agreement. WPS is authorized recovery of this asset over a nine-year period that began on January 1, 2014.

[9] Amounts are recovered over the term of the replacement debt for PGL and NSG as authorized by the ICC.

(10) Prior to WPS purchasing the De Pere Energy Center in 2002, WPS had a long-term power purchase contract with them that was accounted for as a capital lease. As a result of the purchase, the capital lease obligation was reversed, and the difference between the capital lease asset and the purchase price was recorded as a regulatory asset. WPS is authorized recovery of this regulatory asset through 2023.

(11) In 2012, WPS elected to claim and subsequently received a Section 1603 Grant for the Crane Creek wind project in lieu of the production tax credit. As a result, WPS reversed previously recorded production tax credits and recorded regulatory assets. In May 2018, the PSCW issued an order requiring WPS to use a portion of its tax benefits from the Tax Legislation that was signed into law in December 2017 to reduce the regulatory assets related to its Crane Creek wind project production tax credits. See Note 24, Regulatory Environment, for more information.

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]	**$ 902.6**	$ 972.8	15
Removal costs [2]	**386.1**	376.1	
Pension and OPEB costs [3]	**149.8**	95.7	19
Decoupling	**30.5**	1.8	1(d)
Earnings sharing mechanism	**21.2**	—	24
Energy efficiency programs [4]	**18.2**	10.0	
Energy costs refundable through rate adjustments [5]	**17.7**	11.5	1(d)
Derivatives	**11.8**	6.4	1(o)
Other, net	**17.4**	16.7	
Total regulatory liabilities	**$ 1,555.3**	$ 1,491.0	
Balance sheet presentation			
Other current liabilities	**$ 15.1**	$ 11.8	
Regulatory liabilities	**1,540.2**	1,479.2	
Total regulatory liabilities	**$ 1,555.3**	$ 1,491.0	

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

(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.

NOTE 7—PROPERTY, PLANT, AND EQUIPMENT

Property, plant, and equipment consisted of the following utility and non-utility assets at December 31:

(in millions)	2018	2017
Electric - generation	**$ 2,831.2**	$ 2,624.1
Electric - distribution	**1,510.0**	1,361.6
Natural gas - distribution, storage, and transmission	**7,232.8**	6,753.0
Plant to be retired, net	**—**	57.9
Other	**709.6**	582.9
Less: Accumulated depreciation	**3,532.0**	3,270.1
Net	**8,751.6**	8,109.4
CWIP	**324.1**	280.8
Net utility property, plant, and equipment	**9,075.7**	8,390.2
Non-utility and other property, plant, and equipment	**62.9**	88.7
Less: Accumulated depreciation	**9.8**	18.6
Net	**53.1**	70.1
CWIP	**—**	0.1
Net non-utility and other property, plant, and equipment	**53.1**	70.2
Total property, plant, and equipment	**$ 9,128.8**	$ 8,460.4

Wisconsin Segment Plant to be Retired

We have evaluated future plans for our older and less efficient fossil fuel generating units and have retired our plants identified below. In December 2017, a severance liability in the amount of $3.6 million was recorded in other current liabilities related to these plant retirements.

(in millions)	
Severance liability at December 31, 2017	$ 3.6
Severance payments	**(0.8)**
Total severance liability at December 31, 2018	**$ 2.8**

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 8—JOINTLY OWNED UTILITY FACILITIES

WPS holds a joint ownership interest in certain electric generating facilities. WPS is entitled to its share of generating capability and output of each facility equal to its respective ownership interest. WPS also pays its ownership share of additional construction costs, fuel inventory purchases, and operating expenses, unless specific agreements have been executed to limit its maximum exposure to additional costs. WPS records its proportionate share of significant jointly owned electric generating facilities as property, plant, and equipment on the balance sheets.

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

(in millions, except for percentages and MW)	Weston Unit 4	Columbia Energy Center Units 1 and 2 [2]	Forward Wind Energy Center
Ownership	**70.0%**	**28.1%**	**44.6%**
WPS's share of rated capacity (MW) [1]	**384.9**	**314.8**	**8.7**
In-service date	**2008**	**1975 and 1978**	**2008**
Property, plant, and equipment	**$ 615.4**	**$ 438.8**	**$ 123.7**
Accumulated depreciation	**$ (205.2)**	**$ (132.2)**	**$ (43.7)**
CWIP	**$ 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%.

WPS's proportionate share of direct expenses for the joint operation of these plants is recorded in operating expenses in the income statements. WPS has supplied its own financing for all jointly owned projects.

NOTE 9—ASSET RETIREMENT OBLIGATIONS

Our utilities have recorded AROs primarily for the removal of natural gas distribution mains and service pipes (including asbestos and polychlorinated biphenyls [PCBs]); asbestos abatement at certain generation facilities, office buildings, and service centers; 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 PDL for the removal of solar equipment components.

The following table shows changes to our AROs during the years ended December 31:

(in millions)	2018	2017	2016
Balance as of January 1	**$ 501.7**	$ 492.7	$ 509.2
Accretion	**24.4**	24.1	25.1
Additions and revisions to estimated cash flows	**(110.7)** [1]	21.0 [2]	—
Liabilities settled	**(33.9)**	(36.1)	(41.6)
Balance as of December 31	**$ 381.5**	$ 501.7	$ 492.7

[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 $5.6 million ARO was recorded for the legal requirement to dismantle, at retirement, the wind generation project known as Forward Wind Energy Center. See Note 2, Acquisition, for more information on Forward Wind Energy Center.

(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 10—GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill represents the excess of the cost of an acquisition over the fair value of the identifiable net assets acquired. The following table shows our goodwill balances by segment as of December 31, 2018 and 2017. Our goodwill balances did not change during the years ended December 31, 2018 and 2017.

	Wisconsin		Illinois		Other States		Total	
(in millions)	2018	2017	2018	2017	2018	2017	2018	2017
Gross goodwill	**$ 36.4**	$ 36.4	**$ 630.1**	$ 630.1	**$ 267.0**	$ 267.0	**$ 933.5**	$ 933.5
Accumulated impairment losses	**—**	—	**(192.8)**	(192.8)	**(104.9)**	(104.9)	**(297.7)**	(297.7)
Net goodwill	**$ 36.4**	$ 36.4	**$ 437.3**	$ 437.3	**$ 162.1**	$ 162.1	**$ 635.8**	$ 635.8

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.

The identifiable intangible assets other than goodwill listed below are classified as other long-term assets on our balance sheets.

	December 31, 2018			December 31, 2017		
(in millions)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized intangible assets (1)	**$ 8.7**	**$ (7.2)**	**$ 1.5**	$ 8.7	$ (6.0)	$ 2.7
Unamortized intangible assets (2)	**5.7**	**—**	**5.7**	5.7	—	5.7
Total intangible assets	**$ 14.4**	**$ (7.2)**	**$ 7.2**	$ 14.4	$ (6.0)	$ 8.4

(1) Primarily represents contractual service agreements that provide for major maintenance and protection against unforeseen maintenance costs related to the combustion turbine generators at WPS's Fox Energy Center. The remaining weighted-average amortization period for our amortized intangible assets at December 31, 2018, was approximately one year.

(2) Consists primarily of a trade name.

NOTE 11—COMMON EQUITY

Stock-Based Compensation

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

(in millions)	2018	2017	2016
Stock options	**$ 2.8**	$ 2.0	$ 1.4
Restricted stock	**4.9**	2.0	3.4
Performance units	**8.9**	8.7	4.0
Stock-based compensation expense	**$ 16.6**	$ 12.7	$ 8.8
Related tax benefit	**$ 4.6**	$ 5.1	$ 3.5

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

Stock Options

The following is a summary of our employees' WEC Energy Group 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	93,465	$ 56.81		
Granted	**45,740**	**$ 66.02**		
Exercised	**(3,430)**	**$ 56.78**		
Outstanding as of December 31, 2018	**135,775**	**$ 59.91**	**8.1**	**$ 1.3**
Exercisable as of December 31, 2018	**15,365**	**$ 57.36**	**7.6**	**$ 0.2**

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 WEC Energy Group's 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 year ended December 31, 2018, was $0.1 million. Cash received by WEC Energy Group from exercises of its options by our employees was $0.2 million during the year ended December 31, 2018. No WEC Energy Group stock options held by our employees were exercised during the years ended December 31, 2017 and 2016.

As of December 31, 2018, we expected to recognize approximately $1.8 million of unrecognized compensation cost related to unvested and outstanding WEC Energy Group stock options over the next 1.7 years on a weighted-average basis.

During the first quarter of 2019, the Compensation Committee awarded 45,243 non-qualified WEC Energy Group stock options with an 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 is a summary of our employees' WEC Energy Group restricted stock activity during 2018:

Restricted Shares	Number of Shares	Weighted-Average Grant Date Fair Value
Outstanding and unvested as of January 1, 2018	18,030	$ 56.11
Granted	**4,206**	**$ 64.99**
Released	**(8,211)**	**$ 55.94**
Transferred	**198**	**$ 64.99**
Forfeited	**(1,363)**	**$ 58.37**
Outstanding and unvested as of December 31, 2018	**12,860**	**$ 59.02**

The intrinsic value of WEC Energy Group restricted stock held by our employees that was released was $0.5 million and $0.4 million for the years ended December 31, 2018 and 2017, respectively. The actual tax benefit from released restricted shares for the same years was $0.1 million and $0.2 million, respectively. No shares of WEC Energy Group restricted stock held by our employees were released during 2016.

As of December 31, 2018, we expected to recognize approximately $1.8 million of unrecognized compensation cost related to unvested and outstanding WEC Energy Group restricted stock over the next 1.5 years on a weighted-average basis.

During the first quarter of 2019, the Compensation Committee awarded 3,946 WEC Energy Group restricted shares to our 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 18,260; 19,990; and 19,710 WEC Energy Group performance units, respectively, to our officers and other key employees under the WEC Energy Group Performance Unit Plan.

At December 31, 2018, our employees held 51,546 of outstanding WEC Energy Group performance units, including dividend equivalents. A liability of $3.1 million was recorded on our balance sheet at December 31, 2018 related to these outstanding units. As of December 31, 2018, we expected to recognize approximately $8.1 million of unrecognized compensation cost related to unvested and outstanding WEC Energy Group performance units over the next 1.3 years on a weighted-average basis.

During the first quarter of 2019, performance units held by our employees with an intrinsic value of $1.4 million were settled. The actual tax benefit from the distribution of these awards was $0.3 million. In January 2019, the Compensation Committee also awarded 17,099 WEC Energy Group performance units to our officers and other key employees under its normal schedule of awarding long-term incentive compensation.

Restrictions

Our ability to transfer funds to WEC Energy Group primarily depends on the availability of funds from our utility subsidiaries. Various financing arrangements and regulatory requirements impose certain restrictions on the ability of our subsidiaries to transfer funds to us in the form of cash dividends, loans, or advances. All of our utility subsidiaries, with the exception of MGU, are prohibited from loaning funds to us, either directly or indirectly.

In accordance with WPS's most recent rate order, WPS may not pay common dividends above the test year forecasted amounts reflected in its rate case, if it would cause its average common equity ratio, on a financial basis, to fall below its authorized level of 51%. A return of capital in excess of the test year amount can be paid by WPS at the end of the year provided that its average common equity ratio does not fall below the authorized level.

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.

We have the option to defer interest payments on our junior subordinated notes, from time to time, for one or more periods of up to ten consecutive years per period. During any period in which we defer interest payments, we may not declare or pay any dividends or distributions on, or redeem, purchase, acquire, or make a liquidation payment on, any of our capital stock.

See Note 13, Short-Term Debt and Lines of Credit, for discussion of certain financial covenants related to the short-term debt obligations of our subsidiaries.

As of December 31, 2018, restricted net assets of our consolidated subsidiaries totaled approximately $2.5 billion.

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

NOTE 12—PREFERRED STOCK

The following table shows our subsidiaries' authorized shares of preferred stock at December 31, 2018 and 2017. There were no shares outstanding.

	Shares Authorized
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**

NOTE 13—SHORT-TERM DEBT AND LINES OF CREDIT

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

(in millions, except percentages)	2018	2017
Commercial paper		
Amount outstanding at December 31	**$ 479.5**	$ 533.0
Average interest rate on amounts outstanding at December 31	**2.86%**	1.81%

Our average amount of commercial paper borrowings based on daily outstanding balances during 2018, was $431.3 million with a weighted-average interest rate during the period of 2.26%.

WPS and PGL have entered into bank back-up credit facilities to maintain short-term credit liquidity which, among other terms, requires them to maintain, subject to certain exclusions, a total funded debt to capitalization ratio of 65% or less. As of December 31, 2018, both companies were in compliance with their respective financial covenants.

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
Revolving credit facility (WPS)	October 2022	**$ 400.0**
Revolving credit facility (PGL)	October 2022	**350.0**
Revolving short-term notes payable to WEC Energy Group		**400.0**
Total short-term credit capacity		**$ 1,150.0**
Less:		
Commercial paper outstanding		**$ 479.5**
Letters of credit issued inside credit facilities		**1.3**
Short-term debt to WEC Energy Group		**—**
Available capacity under existing credit agreements		**$ 669.2**

The WPS and PGL facilities have renewal provisions 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.

NOTE 14—LONG-TERM DEBT

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

Integrys Holding, Inc.

In May 2018, we redeemed at par all $114.9 million outstanding of our 2006 Junior Subordinated Notes Due 2066.

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.

Bonds and Notes

The following table shows the future maturities of our long-term debt outstanding as of December 31, 2018:

(in millions)	Payments
2019	$ 75.0
2020	250.0
2021	400.0
2022	—
2023	—
Thereafter	2,787.0
Total	$ 3,512.0

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

Effective August 2023, our $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.

Our long-term debt obligations, and those of certain of our subsidiaries, contain covenants related to payment of principal and interest when due and various financial reporting obligations. Failure to comply with these covenants could result in an event of default, which could result in the acceleration of outstanding debt obligations.

NOTE 15—INCOME TAXES

Income Tax Expense

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

(in millions)	2018	2017	2016
Current tax benefit	**$ (20.8)**	$ (16.0)	$ (60.3)
Deferred income taxes, net	**146.2**	239.2	260.8
Investment tax credit, net	**(2.0)**	(1.7)	(3.8)
Total income tax expense	**$ 123.4**	$ 221.5	$ 196.7

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*		2016	
(in millions)	Amount	Effective Tax Rate	Amount	Effective Tax Rate	Amount	Effective Tax Rate
Expected tax at statutory federal tax rates	**$ 98.4**	**21.0 %**	$ 214.2	35.0 %	$ 173.6	35.0 %
State income taxes net of federal tax benefit	**29.7**	**6.3 %**	28.1	4.6 %	23.2	4.7 %
Tax Legislation	**—**	**— %**	(19.3)	(3.2)%	—	— %
AFUDC – Equity	**(1.0)**	**(0.2)%**	(1.4)	(0.2)%	(6.8)	(1.4)%
Other, net	**(3.7)**	**(0.8)%**	(0.1)	— %	6.7	1.3 %
Total income tax expense	**$ 123.4**	**26.3 %**	$ 221.5	36.2 %	$ 196.7	39.6 %

* The net impact of Tax Legislation in the amount of $21.2 million is represented in both the Tax Legislation 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 net tax benefit related to the remeasurement of our deferred taxes in the amount of $1,090 million. Accordingly, the tax benefit related to our regulated operations was recorded as both an increase to regulatory liabilities as well as a decrease to certain existing regulatory assets at December 31, 2017. The effects of the Tax Legislation related to our non-utility and non-regulated operations resulted in the recording of an income tax benefit of $21.2 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 Securities and Exchange Commission 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 at December 31 were as follows:

(in millions)	2018	2017
Deferred tax assets		
Tax gross up – regulatory items	**$ 250.1**	$ 265.0
Future tax benefits	**45.3**	142.9
Other	**70.6**	47.7
Total deferred tax assets	**366.0**	455.6
Valuation allowance	**(11.0)**	(14.2)
Net deferred tax assets	**$ 355.0**	$ 441.4
Deferred tax liabilities		
Property-related	**$ 1,371.6**	$ 1,468.5
Employee benefits and compensation	**72.6**	53.0
Regulatory deferrals	**17.8**	49.4
Other	**22.9**	17.4
Total deferred tax liabilities	**1,484.9**	1,588.3
Deferred tax liability, net	**$ 1,129.9**	$ 1,146.9

Consistent with rate-making treatment, deferred taxes 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	**—**	**20.1**	**(1.3)**	**2038**
State net operating loss	**181.7**	**10.9**	**—**	**2023**
State tax credit	**—**	**4.6**	**—**	**2018**
Balance as of December 31, 2018	**$ 181.7**	**$ 45.3**	**$ (11.0)**	

2017 *(in millions)*	Gross Value	Deferred Tax Effect	Valuation Allowance
Future tax benefits as of December 31, 2017			
Federal foreign tax credit	$ —	$ 13.5	$ (13.5)
Other federal tax credit	—	109.8	(0.1)
Charitable contribution	12.9	3.7	(0.6)
State net operating loss	183.0	11.0	—
State tax credit	—	4.9	—
Balance as of December 31, 2017	$ 195.9	$ 142.9	$ (14.2)

Valuation allowances of $11.0 million have been established for certain tax benefit carryforwards based on our projected ability to realize such benefits by off-setting 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 at January 1	**$ 17.3**	$ 8.8
Increase related to tax positions of prior years	**—**	8.1
Decrease related to tax positions of prior years	**(0.2)**	**—**
Increase related to tax positions of the current year	**—**	0.4
Balance at December 31	**$ 17.1**	$ 17.3

The amount of unrecognized tax benefits at December 31, 2018 and 2017, excludes deferred tax assets related to uncertainty in income taxes of $1.1 million and $1.8 million, respectively. At 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 $16.0 million and $15.5 million, respectively.

For the years ended December 31, 2018 and 2017, we recognized $0.1 million of interest expense and $0.1 million of interest income related to unrecognized tax benefits in our income statements, respectively. For the year ended December 31, 2016, we recognized no interest related to unrecognized tax benefits in our income statement. For the years ended December 31, 2018, 2017, and 2016, we recognized no penalties related to unrecognized tax benefits in our income statements. At December 31, 2018, we had $0.4 million of interest accrued and no penalties accrued related to unrecognized tax benefits on our balance sheets. At 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 is 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, we were subject to examination by federal as well as by state or local tax authorities for the 2013 through 2018 tax years in our major operating jurisdictions as follows:

Jurisdiction	Year
Federal	2015-2018
Illinois	2013-2018
Michigan	2016-2018
Minnesota	2014-2018
Wisconsin	2014-2018

NOTE 16—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	**$ 5.2**	**$ 1.7**	**$ —**	**$ 6.9**
FTRs	**—**	**—**	**3.0**	**3.0**
Coal contracts	**—**	**0.4**	**—**	**0.4**
Total derivative assets	**$ 5.2**	**$ 2.1**	**$ 3.0**	**$ 10.3**
Investments held in rabbi trust	**$ 65.0**	**$ —**	**$ —**	**$ 65.0**
Derivative liabilities				
Natural gas contracts	**$ 3.1**	**$ 0.6**	**$ —**	**$ 3.7**

	December 31, 2017			
(in millions)	Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	$ 1.0	$ 3.4	$ —	$ 4.4
Petroleum products contracts	0.3	—	—	0.3
FTRs	—	—	2.0	2.0
Coal contracts	—	0.4	—	0.4
Total derivative assets	$ 1.3	$ 3.8	$ 2.0	$ 7.1
Investments held in rabbi trust	$ 120.7	$ —	$ —	$ 120.7
Derivative liabilities				
Natural gas contracts	$ 4.1	$ 3.6	$ —	$ 7.7
Coal contracts	—	0.5	—	0.5
Total derivative liabilities	$ 4.1	$ 4.1	$ —	$ 8.2

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. They also include FTRs, which are used to manage electric transmission congestion costs in the MISO Energy Markets. See Note 17, Derivative Instruments, for more information.

We hold investments in our rabbi trust. These investments are restricted as they can only be withdrawn from the trust to fund participants' benefits under our deferred compensation plan and certain 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 and $4.0 million for the years ended December 31, 2017 and 2016, respectively. The net unrealized gains included in earnings for the year ended December 31, 2018 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	**$ 2.0**	$ 2.0	$ 2.0
Realized and unrealized losses	**—**	—	(0.2)
Purchases	**9.0**	6.9	7.1
Sales	**—**	—	(0.2)
Settlements	**(8.0)**	(6.9)	(6.7)
Balance at the end of the period	**$ 3.0**	$ 2.0	$ 2.0

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 are included in 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
Long-term debt, including current portion	**$ 3,477.7**	**$ 3,486.9**	$ 3,249.6	$ 3,499.1

The fair value of long-term debt is categorized within Level 2 of the fair value hierarchy.

NOTE 17—DERIVATIVE INSTRUMENTS

The following table shows our derivative assets and derivative liabilities, none of which are designated as hedging instruments.

	December 31, 2018		December 31, 2017	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Other current				
Natural gas contracts	**$ 6.5**	**$ 3.5**	$ 4.3	$ 6.6
Petroleum products contracts	**—**	**—**	0.3	—
FTRs	**3.0**	**—**	2.0	—
Coal contracts	**0.2**	**—**	—	0.5
Total other current	**$ 9.7**	**$ 3.5**	$ 6.6	$ 7.1
Other long-term				
Natural gas contracts	**$ 0.4**	**$ 0.2**	$ 0.1	$ 1.1
Coal contracts	**0.2**	**—**	0.4	—
Total other long-term	**$ 0.6**	**$ 0.2**	$ 0.5	$ 1.1
Total	**$ 10.3**	**$ 3.7**	$ 7.1	$ 8.2

Realized gains and losses on derivative instruments are primarily recorded in cost of sales on our 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	96.0 Dth	**$ 11.9**	77.2 Dth	$ (5.9)	92.9 Dth	$ (37.7)
Petroleum products contracts	1.8 gallons	**0.4**	1.3 gallons	0.1	4.4 gallons	(0.6)
FTRs	9.3 MWh	**12.5**	9.1 MWh	6.4	8.4 MWh	6.0
Total		**$ 24.8**		$ 0.6		$ (32.3)

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	**$ 10.3**	**$ 3.7**	$ 7.1	$ 8.2
Gross amount not offset on the balance sheet	**(3.0)** [1]	**(3.2)** [2]	(3.3)	(6.1) [3]
Net amount	**$ 7.3**	**$ 0.5**	$ 3.8	$ 2.1

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

(2) Includes cash collateral posted of $0.4 million.

(3) Includes cash collateral posted of $2.8 million.

At December 31, 2018 and 2017, we had posted cash collateral of $1.0 million and $9.4 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.

NOTE 18—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 supporting commodity transactions of subsidiaries [1]	**$ 88.6**	$ 69.6	$ 1.0	$ 18.0
Standby letters of credit [2]	**21.4**	—	0.2	21.2
Other guarantees [3]	**17.7**	—	10.0	7.7
Total guarantees	**$ 127.7**	$ 69.6	$ 11.2	$ 46.9

(1) Consists of (a) $5.0 million and $6.0 million to support the business operations of WBS and PDL, respectively; and (b) $62.1 million and $15.5 million related to natural gas supply at MERC and MGU, respectively. These amounts are not reflected on our balance sheets.

(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) Consists of (a) $7.7 million to support PDL's future payment obligations related to its distributed solar generation projects, of which $6.6 million is covered by a reciprocal guarantee from a third party that is not reflected on our balance sheets and (b) $10.0 million related to the sale of a nonregulated retail marketing business previously owned by us, of which an insignificant liability was recorded.

NOTE 19—EMPLOYEE BENEFITS

Pension and Other Postretirement Employee Benefits

Through December 31, 2016, we maintained a noncontributory, qualified pension plan sponsored by WBS that covered the majority of our employees. Effective January 1, 2017, that plan was split into six separate plans. While the split did not impact our pension benefit obligation, federal regulations required a different allocation of assets among the new plans. We maintain several unfunded non-qualified retirement plans and our subsidiaries maintain noncontributory, qualified pension 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. WEC Energy Group also offers medical, dental, and life insurance benefits to active employees and their dependents. We expense the costs of these benefits as incurred.

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. In October 2017, we remeasured the obligations of our OPEB plan as a result of a plan design change to move all participants to the same Medicare Advantage plan design starting January 1, 2018.

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	**$ 1,359.3**	$ 1,297.6	**$ 394.4**	$ 408.4
Service cost	**27.0**	26.0	**13.0**	13.9
Interest cost	**50.0**	52.1	**14.3**	16.3
Plan amendments	**—**	—	**(3.3)**	(27.1)
Actuarial (gain) loss	**(81.4)**	79.4	**(111.6)**	1.6
Participant contributions	**—**	—	**6.0**	5.9
Benefit payments	**(93.1)**	(95.8)	**(23.3)**	(24.6)
Transfer	**—**	**—**	**(5.4)**	—
Obligation at December 31	**$ 1,261.8**	$ 1,359.3	**$ 284.1**	$ 394.4
Change in fair value of plan assets				
Fair value at January 1	**$ 1,198.6**	$ 1,017.2	**$ 452.9**	$ 419.6
Actual return on plan assets	**(67.4)**	171.9	**(19.4)**	50.4
Employer contributions	**60.7**	68.8	**0.4**	1.4
Net transfer from affiliates	**—**	36.5 *	**—**	0.2 *
Participant contributions	**—**	—	**6.0**	5.9
Benefit payments	**(93.1)**	(95.8)	**(23.3)**	(24.6)
Transfer	**—**	—	**(0.1)**	—
Fair value at December 31	**$ 1,098.8**	$ 1,198.6	**$ 416.5**	$ 452.9
Funded status at December 31	**$ (163.0)**	$ (160.7)	**$ 132.4**	$ 58.5

* Related to our receipt of pension assets from affiliates as a result of our pension plan split for the year ended December 31, 2017. Assets were transferred into our plan in January 2017. See Note 4, Related Parties, for more information.

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	**$ 9.0**	$ 29.5	**$ 148.6**	$ 78.1
Pension and OPEB obligations	**172.0**	190.2	**16.2**	19.6
Total net (liabilities) assets	**$ (163.0)**	$ (160.7)	**$ 132.4**	$ 58.5

The accumulated benefit obligation for the defined benefit pension plans was $1,141.9 million and $1,255.7 million at 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	**$ 484.4**	$ 529.8
Accumulated benefit obligation	**438.1**	481.1
Fair value of plan assets	**329.9**	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 income (loss) [1]				
Net actuarial loss (gain)	**$ 24.3**	$ 28.2	**$ (1.8)**	$ (1.6)
Prior service credits	**—**	—	**(0.1)**	(0.2)
Total	**$ 24.3**	$ 28.2	**$ (1.9)**	$ (1.8)
Net regulatory assets (liabilities) [2]				
Net actuarial loss (gain)	**$ 513.5**	$ 493.9	**$ (81.4)**	$ (20.1)
Prior service costs (credits)	**7.1**	8.8	**(92.5)**	(102.1)
Total	**$ 520.6**	$ 502.7	**$ (173.9)**	$ (122.2)

[1] Amounts related to the nonregulated entities are included in accumulated other comprehensive loss.

[2] Amounts related to the utilities 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)	$ 45.9	$ (3.8)
Prior service costs (credits)	1.7	(13.2)
Total 2019 – estimated amortization	$ 47.6	$ (17.0)

The components of net periodic benefit cost for the years ended December 31 are as follows:

	Pension Costs			OPEB Costs		
(in millions)	2018	2017	2016	2018	2017	2016
Service cost	**$ 27.0**	$ 26.0	$ 27.9	**$ 13.0**	$ 13.9	$ 15.8
Interest cost	**50.0**	52.1	54.4	**14.3**	16.3	18.8
Expected return on plan assets	**(79.3)**	(78.5)	(75.2)	**(32.1)**	(30.2)	(28.8)
(Gain) loss on plan settlement	**(0.1)**	3.0	9.9	**—**	—	—
Amortization of prior service cost (credit)	**1.7**	1.7	1.7	**(12.8)**	(10.7)	(8.1)
Amortization of net actuarial loss	**49.7**	45.6	46.7	**1.3**	2.9	5.6
Net periodic benefit cost (credit)	**$ 49.0**	$ 49.9	$ 65.4	**$ (16.3)**	$ (7.8)	$ 3.3

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. 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)	2017 Annual Report Income Statement	Impact of ASU 2017-07	Income Statement After Adoption	2017 Annual Report Income Statement	Impact of ASU 2017-07	Income Statement After Adoption
Operating expenses						
Other operation and maintenance	$ 1,017.6	$ (1.6)	$ 1,016.0	$ 1,156.9	$ (18.9)	$ 1,138.0
Other expense						
Other income, net	38.3	(1.6)	36.7	52.1	(18.9)	33.2

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%**	3.69%	**4.25%**	3.62%
Rate of compensation increase	**4.00%**	4.00%	**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	**5.90%**	6.00%
Ultimate trend rate (Post 65)	**N/A**	N/A	**5.00%**	5.00%
Year ultimate trend rate is reached (Post 65)	**N/A**	N/A	**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	**3.75%**	4.13%	4.26%
Expected return on assets	**7.25%**	7.25%	7.25%
Rate of compensation increase	**4.00%**	4.00%	4.00%

	OPEB Costs		
	2018	2017	2016
Discount rate	**3.62%**	4.00%	4.34%
Expected return on 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)	**6.00%**	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

WEC Energy Group consults with its investment advisors on an annual basis to help 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 for the pension and OPEB plans is 7.25%.

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	$ 4.0	$ (3.1)
Effect on health care component of the accumulated postretirement benefit obligations	23.4	(19.3)

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 payments 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.

Our pension plan's assets are invested in a corporate pension trust with a target asset allocation of 45% equity investments, 45% fixed income investments, and 10% private equity and real estate investments. Our two largest OPEB trusts have target asset allocations of 45% equity investments and 55% fixed income investments, and 50% equity investments and 50% fixed income investments, respectively. Equity securities include investments in large-cap, mid-cap, and small-cap companies primarily located in the United States. 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	$ 135.7	$ —	$ —	$ 135.7	$ 45.3	$ —	$ —	$ 45.3
International Equity	137.7	0.5	—	138.2	50.3	0.1	—	50.4
Fixed income securities: *								
United States Bonds	28.0	204.7	—	232.7	79.4	64.6	—	144.0
International Bonds	4.0	36.1	—	40.1	4.3	3.1	—	7.4
	$ 305.4	$ 241.3	$ —	$ 546.7	$ 179.3	$ 67.8	$ —	$ 247.1
Investments measured at net asset value				$ 552.1				$ 169.4
Total	$ 305.4	$ 241.3	$ —	$ 1,098.8	$ 179.3	$ 67.8	$ —	$ 416.5

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

	December 31, 2017							
	Pension Plan Assets				OPEB Plan Assets			
(in millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Asset Class								
Cash and cash equivalents	$ —	$ 37.4	$ —	$ 37.4	$ 16.2	$ 0.8	$ —	$ 17.0
Equity securities:								
United States Equity	164.7	—	—	164.7	50.4	—	—	50.4
International Equity	165.2	—	0.7	165.9	59.5	—	0.2	59.7
Fixed income securities: *								
United States Bonds	30.0	217.4	—	247.4	80.5	63.1	—	143.6
International Bonds	3.9	35.6	—	39.5	4.2	3.4	—	7.6
Private Equity and Real Estate	—	105.7	21.1	126.8	—	2.2	0.4	2.6
	$ 363.8	$ 396.1	$ 21.8	$ 781.7	$ 210.8	$ 69.5	$ 0.6	$ 280.9
Investments measured at net asset value				$ 416.9				$ 172.0
Total	$ 363.8	$ 396.1	$ 21.8	$ 1,198.6	$ 210.8	$ 69.5	$ 0.6	$ 452.9

* 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:

	Private Equity and Real Estate		International Equity	
(in millions)	Pension	OPEB	Pension	OPEB
Beginning balance at January 1, 2018	**$ 21.1**	**$ 0.4**	**$ 0.7**	**$ 0.2**
Realized and unrealized losses	**1.7**	**—**	**(0.1)**	**—**
Purchases	**4.1**	**0.1**	**—**	**—**
Liquidations	**(0.1)**	**—**	**—**	**—**
Transfers out of level 3	**(26.8)**	**(0.5)**	**(0.6)**	**(0.2)**
Ending balance at December 31, 2018	**$ —**	**$ —**	**$ —**	**$ —**

	Private Equity and Real Estate		International Equity		U.S. Bonds
(in millions)	Pension	OPEB	Pension	OPEB	Pension
Beginning balance at January 1, 2017	$ —	$ —	$ —	$ —	$ 0.6
Realized and unrealized losses	—	—	(0.2)	—	(0.6)
Purchases	21.1	0.4	0.9	0.2	—
Ending balance at December 31, 2017	$ 21.1	$ 0.4	$ 0.7	$ 0.2	**$ —**

Cash Flows

We expect to contribute $0.7 million to the pension plans and $0.3 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	OPEB
2019	$ 101.4	$ 16.7
2020	97.3	18.8
2021	99.9	19.8
2022	97.3	19.8
2023	94.0	20.5
2024 through 2028	430.2	108.7

Savings Plans

WEC Energy Group sponsors a 401(k) savings plan that allows substantially all of our full-time 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, which amounts are contributed to an employee's savings plan account based on the employee's wages, age, and years of service. Our share of the total costs incurred under all of these plans was $22.1 million in 2018, $21.7 million in 2017, and $19.0 million in 2016.

NOTE 20—INVESTMENT IN AMERICAN TRANSMISSION COMPANY

At December 31, 2017, our electric transmission investment segment consisted of WPSI's ownership interest in ATC, which was approximately 34%. In January 2018, we transferred our ownership interest in ATC to another subsidiary of WEC Energy Group. ATC is 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-related projects. The following table provides a reconciliation of the changes in our investment in ATC:

(in millions)	2018	2017	2016
Balance at January 1	**$ 621.1**	$ 600.2	$ 550.4
Less: Transfer of ownership interest	**621.1**	—	—
Add: Earnings from equity method investment	**—**	93.8	82.2
Add: Capital contributions	**—**	34.1	23.9
Less: Distributions	**—**	107.0 *	56.2
Less: Other	**—**	—	0.1
Balance at December 31	**$ —**	$ 621.1	$ 600.2

* Of this amount, $22.5 million was recorded as a receivable from ATC in other current assets at December 31, 2017.

See Note 4, Related Parties, for more information on transactions with ATC.

NOTE 21—SEGMENT INFORMATION

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

- The Wisconsin segment includes the electric and natural gas utility and non-utility operations of WPS. Through December 31, 2016, the Wisconsin segment included WPS's electric and natural gas operations in the Upper Peninsula of Michigan. Effective January 1, 2017, WPS transferred its customers and electric and natural gas distribution assets located in the Upper Peninsula of Michigan to UMERC. See Note 4, Related Parties, for more information on 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.

- Through December 31, 2017, the electric transmission investment segment included our approximate 34% 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. In January 2018, we transferred our ownership interest in ATC to another subsidiary of WEC Energy Group. See Note 4, Related Parties, for more information.

- The corporate and other segment includes the operations of the Integrys holding company, the PELLC holding company, PDL, and ITF. The sale of ITF was completed in the first quarter of 2016. See Note 3, Disposition, for more information on the sale of ITF.

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.

	Regulated Operations							
2018 *(in millions)*	**Wisconsin**	**Illinois**	**Other States**	**Electric Transmission Investment**	**Total Regulated Operations**	**Corporate and Other**	**Reconciling Eliminations**	**Integrys Holding Consolidated**
External revenues	**$ 1,498.5**	**$1,400.0**	**$ 438.2**	**$ —**	**$ 3,336.7**	**$ 8.0**	**$ —**	**$ 3,344.7**
Other operation and maintenance	**448.0**	**472.3**	**101.0**	**—**	**1,021.3**	**7.1**	**—**	**1,028.4**
Depreciation and amortization	**141.9**	**170.3**	**24.1**	**—**	**336.3**	**2.4**	**—**	**338.7**
Operating income (loss)	**266.4**	**255.8**	**68.8**	**—**	**591.0**	**(1.1)**	**—**	**589.9**
Interest expense	**53.9**	**51.2**	**8.7**	**—**	**113.8**	**37.8**	**(0.8)**	**150.8**
Capital expenditures and asset acquisitions	**521.4**	**545.0**	**102.9**	**—**	**1,169.3**	**—**	**—**	**1,169.3**
Total assets	**5,217.7**	**6,162.3**	**1,127.0**	**—**	**12,507.0**	**410.0**	**(71.4)**	**12,845.6**

	Regulated Operations							
2017 *(in millions)*	**Wisconsin**	**Illinois**	**Other States**	**Electric Transmission Investment**	**Total Regulated Operations**	**Corporate and Other**	**Reconciling Eliminations**	**Integrys Holding Consolidated**
External revenues	$ 1,485.4	$1,355.5	$ 411.2	$ —	$ 3,252.1	$ 12.8	$ —	$ 3,264.9
Other operation and maintenance *	447.5	464.4	101.0	—	1,012.9	3.1	—	1,016.0
Depreciation and amortization	139.3	152.6	24.8	—	316.7	3.6	—	320.3
Operating income *	285.1	279.9	54.4	—	619.4	6.0	—	625.4
Equity in earnings of transmission affiliate	—	—	—	93.8	93.8	—	—	93.8
Interest expense	54.3	45.0	8.7	—	108.0	40.1	(4.1)	144.0
Capital expenditures	335.8	545.2	74.5	—	955.5	4.5	—	960.0
Total assets	4,741.3	5,823.3	1,045.9	643.7	12,254.2	599.6	(83.0)	12,770.8

* Includes the retroactive restatement impacts of the implementation of ASU 2017-07. See Note 19, Employee Benefits, for more information on this new standard.

	Regulated Operations							
2016 *(in millions)*	**Wisconsin**	**Illinois**	**Other States**	**Electric Transmission Investment**	**Total Regulated Operations**	**Corporate and Other**	**Reconciling Eliminations**	**Integrys Holding Consolidated**
External revenues	$ 1,448.2	$1,242.2	$ 376.6	$ —	$ 3,067.0	$ 21.9	$ —	$ 3,088.9
Other operation and maintenance *	503.7	509.1	112.6	—	1,125.4	12.6	—	1,138.0
Depreciation and amortization	124.1	134.0	21.1	—	279.2	4.3	—	283.5
Operating income (loss) *	253.0	215.6	47.5	—	516.1	(1.2)	—	514.9
Equity in earnings of transmission affiliate	—	—	—	82.2	82.2	—	—	82.2
Interest expense	48.1	38.9	8.5	—	95.5	46.7	(8.0)	134.2
Capital expenditures	311.2	293.2	59.5	—	663.9	1.7	—	665.6
Total assets	4,639.4	5,392.7	966.2	600.2	11,598.5	464.1	(233.8)	11,828.8

* Includes the retroactive restatement impacts of the implementation of ASU 2017-07. See Note 19, Employee Benefits, for more information on this new standard.

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

The 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:								
Purchased power	2041	$ 410.8	$ 75.1	$ 48.2	$ 46.8	$ 41.8	$ 39.7	$ 159.2
Coal supply and transportation	2024	325.4	115.0	63.1	48.2	47.6	50.8	0.7
Natural gas utility supply and transportation	2048	1,157.1	202.0	168.8	107.5	83.9	51.9	543.0
Total		$ 1,893.3	$ 392.1	$ 280.1	$ 202.5	$ 173.3	$ 142.4	$ 702.9

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 $2.6 million, $3.8 million, and $2.4 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	$ 0.5
2020	0.3
2021	0.3
2022	0.3
2023	0.3
Later years	2.9
Total	$ 4.6

Environmental Matters

Consistent with other companies in the energy industry, we face significant ongoing environmental compliance and remediation obligations related to current and past operations. Specific environmental issues affecting us include, but are not limited to, current and future regulation of air emissions such as sulfur dioxide, nitrogen oxide, 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 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 National Ambient Air Quality Standards. The EPA issued final nonattainment area designations on May 1, 2018. The following counties within our service territories were designated as partial nonattainment: Door, Manitowoc, 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 Affordable Clean Energy (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. WEC Energy Group's plan, which includes us, 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 WEC Energy Group's CO_2 reduction goals. As a result of WEC Energy Group's generation reshaping plan, we retired approximately 300 MW of coal generation in 2018, consisting of the Pulliam power plant and the jointly-owned Edgewater Unit 4 generation units. See Note 7, 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 5.7 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 6.4 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 emissions related to the natural gas that our natural gas utilities distribute and sell. For 2017, we reported aggregated CO_2 equivalent emissions of approximately 16.9 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 18.9 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.

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 7, 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 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 retirement of Pulliam Units 7 and 8, we do not believe that BTA determinations will be necessary for these units. We also have provided information to the WDNR about planned unit retirements.

As a result of past capital investments completed to address 316(b) compliance at 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 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 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 facility that will require bottom ash system modifications is Weston Unit 3. Based on preliminary engineering, the estimated rule compliance cost is approximately $20 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 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	**$ 577.2**	$ 598.9
Reserves for future remediation	**525.4**	557.5

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. WPS achieved a renewable energy percentage of 9.74% and met its compliance requirements by constructing various wind parks and by also relying on renewable energy purchases. WPS continues to review its renewable energy portfolios and acquire cost-effective renewables as needed to meet its requirements on an ongoing basis. The PSCW administers the renewable program related to Act 141, and WPS funds the program, along with other utilities, based on 1.2% of its annual operating revenues.

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.

Manlove Field Matter

In September 2017, the Illinois Department of Natural Resources, Office of Oil and Gas Resource Management, issued an NOV to PGL related to a leak of natural gas that PGL identified at its Manlove Gas Storage Field in December 2016. PGL quickly contained the leak

after it was discovered. The leak resulted in the migration of natural gas from a well located at the facility to the Mahomet Aquifer located in central Illinois, which impacted residential freshwater wells. PGL has been working with residents potentially impacted by the natural gas leak, and the Illinois state agencies to investigate and remediate the impacts of the natural gas leak to the Mahomet Aquifer. In October 2017, the Illinois Attorney General (AG) filed a complaint against PGL alleging certain violations of the Illinois Environmental Protection Act and the Oil and Gas Act. PGL entered into an interim order with the State of Illinois in October 2017 whereby PGL agreed, among other things, to continue actions it was already undertaking proactively. In addition, in December 2017, the Illinois Environmental Protection Agency served an NOV to PGL alleging the same violations as the AG, and in January 2018, served an NOV alleging certain violations of Illinois air emission rules arising from the construction and operation of flaring equipment at the leak site. Both matters have been referred to the AG for enforcement.

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

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 7, 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.

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 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 7, Property, Plant, and Equipment, for more information about the retirement.

NOTE 23—SUPPLEMENTAL CASH FLOW INFORMATION

(in millions)	2018	2017	2016
Cash (paid) for interest, net of amount capitalized	**$ (146.1)**	$ (137.7)	$ (137.5)
Cash (paid) received for income taxes, net	**(1.1)**	58.9	149.6
Significant non-cash transactions:			
Accounts payable related to construction costs	**60.4**	141.9	161.0
Receivable related to corporate-owned life insurance proceeds	**7.7**	—	—
Non-cash equity transfer of WPSI's ownership interest in ATC and related taxes to another subsidiary of WEC Energy Group *	**363.4**	—	—
Non-cash equity transfer of net assets to UMERC *	**0.4**	20.6	—
Non-cash equity transfer of our ownership in WBS to WEC Energy Group *	**—**	—	73.0

* See Note 4, Related Parties, for more information on these transactions.

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 our rabbi trust, which are used to fund participants' benefits under our deferred compensation plan and certain 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 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 Annual Report Cash Flows	Impact of ASU 2016-18	Cash Flows After Adoption	2017 Annual Report Cash Flows	Impact of ASU 2016-18	Cash Flows After Adoption
Operating Activities						
Change in –						
Other current assets	$ 6.4	$ (1.1)	$ 5.3	$ 1.5	$ 0.1	$ 1.6
Other, net	(73.4)	0.1	(73.3)	22.5	0.2	22.7
Net cash provided by operating activities	829.0	(1.0)	828.0	804.3	0.3	804.6
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	(1,265.6)	(14.5)	(1,280.1)	(638.4)	(84.1)	(722.5)
Net change in cash, cash equivalents, and restricted cash	7.3	(15.5)	(8.2)	(7.4)	(83.8)	(91.2)
Cash, cash equivalents, and restricted cash at beginning of year	12.0	35.2	47.2	19.4	119.0	138.4
Cash, cash equivalents, and restricted cash at end of year	$ 19.3	$ 19.7	$ 39.0	$ 12.0	$ 35.2	$ 47.2

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	**$ 24.7**	$ 19.3	$ 12.0
Restricted cash included in other current assets	**—**	—	0.8
Restricted cash included in other long-term assets	**57.3**	19.7	34.4
Cash, cash equivalents, and restricted cash	**$ 82.0**	$ 39.0	$ 47.2

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 $1,069 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 WPS's electric utility operations to use 40% of the current 2018 and 2019 tax benefits to reduce certain regulatory assets. The remaining 60% is to be returned to electric customers in the form of bill credits. For WPS's 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 WPS's electric utility operations and is being deferred for its natural gas utility operations. The timing and method of returning the remaining net tax benefit associated with the revaluation of deferred taxes for WPS's electric and natural gas utility operations 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%. MGU proposed providing a volumetric bill credit, subject to reconciliation and true up. In May 2018, the MPSC issued an order approving a settlement that resulted in volumetric bill credits for all of 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. MGU proposed to return the tax savings from these months to customers via volumetric bill credits over multiple months. The MPSC issued an order approving a settlement in September 2018. In accordance with the settlement order, the savings were returned to 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. 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.

Wisconsin Public Service Corporation

2018 and 2019 Rates

During April 2017, WPS, along with WE and WG, 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 WPS's electric and natural gas customers. Based on the PSCW order, WPS's authorized ROE remains at 10.0%, and its current capital cost structure 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. Additionally, the agreement 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 its 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 agreed to keep the mechanism in place through 2019. Under this earnings sharing mechanism, if 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, WPS anticipates 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, Acquisition, for more information.

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, WEC Energy Group signed an agreement for the acquisition of Bluewater. Bluewater owns natural gas storage facilities in Michigan that provide a portion of the current storage needs for WPS's natural gas utility operations. As a result of this agreement, WPS, along with WE and WG, filed a request with the PSCW in February 2017 for a declaratory ruling on various items associated with the storage facilities. In the filing, WPS requested that the PSCW review and confirm the reasonableness and prudency of its potential long-term storage service agreement and interstate natural gas transportation contract related to the storage facilities. WPS, along with WE and WG, also requested approval to amend WEC Energy Group's AIA to ensure WBS and WEC Energy Group's other subsidiaries could provide services to the storage facilities. During June 2017, the PSCW granted, subject to various conditions, these declarations and approvals, and WEC Energy Group acquired Bluewater on June 30, 2017. In September 2017, WPS entered into the long-term service agreement for the natural gas storage, which was then approved by the PSCW in November 2017.

2016 Wisconsin 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, system support resource 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

Natural Gas System Modernization Program 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 2019, PGL filed its 2018 reconciliation with the ICC, which, along with the 2017, 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%. In February 2019, this petition was denied by the MPUC. Interim rates remain in effect until final rates are implemented, which is expected to be in the second quarter of 2019. MERC’s customers will be entitled to a refund to the extent the interim rate increase exceeds the final approved rate increase. Therefore, as of December 31, 2018, MERC recorded a $5.1 million regulatory liability for amounts to be refunded to customers.

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.

NOTE 25—ACCUMULATED OTHER COMPREHENSIVE LOSS

The following table shows the changes, net of tax, to our accumulated other comprehensive loss:

(in millions)	Cash Flow Hedges	Defined Benefit Plans	Accumulated Other Comprehensive Loss
Balance at December 31, 2015	$ (2.5)	$ (25.9)	$ (28.4)
Other comprehensive income before reclassifications	—	0.2	0.2
Amounts reclassified out of accumulated other comprehensive loss	0.6	4.3	4.9
Net 2016 other comprehensive income	0.6	4.5	5.1
Balance at December 31, 2016	(1.9)	(21.4)	(23.3)
Other comprehensive income before reclassifications	—	1.0	1.0
Amounts reclassified out of accumulated other comprehensive loss	0.5	4.3	4.8
Net 2017 other comprehensive income	0.5	5.3	5.8
Balance at December 31, 2017	(1.4)	(16.1)	(17.5)
Other comprehensive loss before reclassifications	**—**	**(2.2)**	**(2.2)**
Amounts reclassified out of accumulated other comprehensive loss	**0.6**	**5.1**	**5.7**
Cumulative effect adjustment from adoption of ASU 2018-02 *	**(0.2)**	**(3.0)**	**(3.2)**
Net 2018 other comprehensive income (loss)	**0.4**	**(0.1)**	**0.3**
Balance at December 31, 2018	**$ (1.0)**	**$ (16.2)**	**$ (17.2)**

* During the fourth quarter of 2018, we early adopted ASU 2018-02. As a result, we reclassified the stranded tax effects associated with the Tax Legislation from accumulated other comprehensive loss to retained earnings. See Note 1(m), Income Taxes, for more information.

NOTE 26—OTHER INCOME, NET

Total other income, net was as follows for the years ended December 31:

(in millions)	2018	2017	2016
(Losses) gains on investments held in rabbi trust	**$ (1.8)**	$ 21.5	$ 5.1
Non-service credit (cost) components of net periodic benefit costs	**4.4**	(1.6)	(18.9)
AFUDC – Equity	**4.6**	4.2	19.5
Interest income from parent	**4.6**	2.5	—
Gain on repurchase of notes	**—**	—	25.7
Other, net	**17.8**	10.1	1.8
Total other income, net	**$ 29.6**	$ 36.7	$ 33.2

NOTE 27—NEW ACCOUNTING PRONOUNCEMENTS

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 annual report for the year ended December 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 less than $5 million, and we had no capital leases upon adoption. 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 consolidated 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.

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2018

OR

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

For the transition period from _____ to _____

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

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

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

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

None

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

Yes [X] No [ ]

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

Yes [ ] No [X]

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes [X] No [ ]

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).

Yes [X] No [ ]

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

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

Large accelerated filer [X]	Accelerated filer [ ]
Non-accelerated filer [ ]	Smaller reporting company [ ]
	Emerging growth company [ ]

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

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes [ ] No [X]

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

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

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

Documents incorporated by reference:

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

WEC ENERGY GROUP, INC.
ANNUAL REPORT ON FORM 10-K
For the Year Ended December 31, 2018
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GLOSSARY OF TERMS AND ABBREVIATIONS

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

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

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

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 described in Item 1A. Risk Factors and those identified below:

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

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

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

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

- The timely completion of capital projects within budgets, as well as the recovery of the related costs through rates;

- The impact of federal, state, and local legislative and/or regulatory changes, including changes in rate-setting policies or procedures, deregulation and restructuring of the electric and/or natural gas utility industries, transmission or distribution system operation, the approval process for new construction, reliability standards, pipeline integrity and safety standards, allocation of energy assistance, energy efficiency mandates, and tax laws that affect our ability to use production tax credits and investment tax credits;

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

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

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

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

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

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.

PART I

ITEM 1. BUSINESS

A. INTRODUCTION

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

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

WEC Energy Group, Inc.

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

Available Information

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

B. UTILITY ENERGY OPERATIONS

Wisconsin Segment

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

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

Electric Utility Operations

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

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

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

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

Operating Revenues

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

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

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

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

Electric Sales

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

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

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

Steam Sales

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

Electric Sales Forecast

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

Customers

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

Large Electric Retail Customers

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

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

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

Wholesale Customers

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

Resale

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

Electric Generation and Supply Mix

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

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

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

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

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

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

[4] Includes hydroelectric, biomass, and wind generation.

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

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

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

Reshaping our Generation Fleet

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

Coal-Fired Generation

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

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

Natural Gas-Fired Generation

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

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

Oil-Fired Generation

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

Renewable Generation

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

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

Solar

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

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

Hydroelectric

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

Wind

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

Biomass

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

Electric System Reliability

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

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

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

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

Fuel and Purchased Power Costs

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

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

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

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

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

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

Coal Supply

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

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

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

Coal Deliveries

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

Midcontinent Independent System Operator Costs

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

Power Purchase Commitments

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

Other Matters

Seasonality

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

Competition

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

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

Environmental Matters

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

Natural Gas Utility Operations

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

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

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

Operating Revenues

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

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

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

Natural Gas Sales Forecast

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

Customers

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

Natural Gas Supply, Pipeline Capacity and Storage

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

Pipeline and Storage Capacity

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

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

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

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

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

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

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

Natural Gas Supply

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

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

Hedging Natural Gas Supply Prices

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

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

Seasonality

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

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

Competition

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

Illinois Segment

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

Illinois Utilities Operating Statistics

Operating Revenues

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

	Year Ended December 31	
(in millions)	**2017**	**2016**
Operating revenues		
Residential	$ 934.8	$ 839.2
Commercial and industrial	156.7	136.5
Total retail revenues	1,091.5	975.7
Transport	246.9	239.4
Other operating revenues	17.1	27.1
Total operating revenues	$ 1,355.5	$ 1,242.2

Customers

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

Natural Gas Supply, Pipeline Capacity, and Storage

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

Pipeline Capacity and Storage

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

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

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

Natural Gas Supply

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

Hedging Natural Gas Supply Prices

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

Natural Gas System Modernization Program

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

Seasonality

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

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

Competition

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

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

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

Other States Segment

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

Other States Utilities Operating Statistics

Operating Revenues

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

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

Customers

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

Natural Gas Supply, Pipeline Capacity and Storage

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

Pipeline Capacity and Storage

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

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

Natural Gas Supply

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

Hedging Natural Gas Supply Prices

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

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

Seasonality

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

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

Competition

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

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

Electric Transmission Segment

ATC is a regional transmission company that owns, maintains, monitors, and operates electric transmission systems in Wisconsin, Michigan, Illinois, and Minnesota. ATC is expected to provide comparable service to all customers, including WE, WPS, and UMERC, and to support effective competition in energy markets without favoring any market participant. ATC is regulated by the FERC for all rate terms and conditions of service and is a transmission-owning member of MISO. MISO maintains operational control of ATC's transmission system, and WE, WPS, and UMERC are non-transmission owning members and customers of MISO. As of December 31, 2018, our ownership interest in ATC was approximately 60%. In addition, we own approximately 75% of ATC Holdco, a separate entity formed in December 2016 to invest in transmission-related projects outside of ATC's traditional footprint.

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

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

C. NON-UTILITY OPERATIONS

Non-Utility Energy Infrastructure Segment

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

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

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

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

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

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

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

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

Corporate and Other Segment

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

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

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

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

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

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

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

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

D. REGULATION

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

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

Regulated Utility Operations

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

Rates

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

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

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

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

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

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

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

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

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

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

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

Electric Transmission, Capacity, and Energy Markets

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

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

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

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

Other Electric Regulations

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

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

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

Other Natural Gas Regulations

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

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

Non-Utility Energy Infrastructure Operations

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

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

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

E. ENVIRONMENTAL COMPLIANCE

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

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

F. EMPLOYEES

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

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

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

	Number of Employees	Expiration Date of Current Labor Agreement
WE		
Local 2150 of International Brotherhood of Electrical Workers	1,611	August 15, 2020
Local 420 of International Union of Operating Engineers	360	September 30, 2021
Local 2006 Unit 1 of United Steel Workers of America	114	October 31, 2021
Local 510 of International Brotherhood of Electrical Workers	75	October 31, 2020
Total WE	2,160	
WPS		
Local 420 of International Union of Operating Engineers	850	April 16, 2021
WG		
Local 2150 of International Brotherhood of Electrical Workers	81	August 15, 2020
Local 2006 Unit 1 of United Steel Workers of America	209	October 31, 2021
Total WG	290	
PGL		
Local 18007 of Utility Workers Union of America	990	April 30, 2023
Local 18007(C) of Utility Workers Union of America	92	July 31, 2021
Total PGL	1,082	
NSG		
Local 2285 of International Brotherhood of Electrical Workers [(1)]	121	June 30, 2019
MERC		
Local 31 of International Brotherhood of Electrical Workers	43	May 31, 2020
Local 49 of International Union of Operating Engineers[(2)]	3	January 1, 2022
Total MERC	46	
MGU		
Local 12295 of United Steelworkers of America	70	January 15, 2020
Local 417 of Utility Workers Union of America	25	February 15, 2022
Total MGU	95	
Total represented employees	4,644	

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

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

ITEM 1A. RISK FACTORS

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

Risks Related to Legislation and Regulation

Our business is significantly impacted by governmental regulation and oversight.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

and local taxing authorities continue to evaluate the impact of federal income tax reform, and any changes on the state or local level could lessen or increase the impacts of the Tax Legislation.

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

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

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

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

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

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

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

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

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

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

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

Risks Related to the Operation of Our Business

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

As a holding company with no operations of our own, our ability to meet our financial obligations including, but not limited to, debt service, taxes, and other expenses, as well as pay dividends on our common stock, is dependent upon the ability of our subsidiaries to pay amounts to us, whether through dividends or other payments. Our subsidiaries are separate legal entities that are not required to pay any of our obligations or to make any funds available for that purpose or for the payment of dividends on our common stock. The ability of our subsidiaries to pay amounts to us depends on their earnings, cash flows, capital requirements, and general financial condition, as well as regulatory limitations. Prior to distributing cash to us, our subsidiaries have financial obligations

that must be satisfied, including, among others, debt service and preferred stock dividends. In addition, each subsidiary's ability to pay amounts to us depends on any statutory, regulatory, and/or contractual restrictions and limitations applicable to such subsidiary, which may include requirements to maintain specified levels of debt or equity ratios, working capital, or other assets. Our utility subsidiaries are regulated by various state utility commissions, which generally possess broad powers to ensure that the needs of the utility customers are being met.

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

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

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

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

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

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

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

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

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

Risks Related to Economic and Market Volatility

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

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

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

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

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

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

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

Any downgrade by the rating agencies could:

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

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

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

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

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

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

Changes in commodity prices could result in:

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

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

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

The use of derivative contracts could result in financial losses.

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

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

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

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

earn a distribution charge for transporting the natural gas for these customers. It is uncertain whether retail choice might be implemented in Wisconsin or Minnesota.

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

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

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

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

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

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

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

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

A. REGULATED

Electric Facilities

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

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

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

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

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

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

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

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

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

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

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

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

Natural Gas Facilities

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

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

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

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

Steam Facilities

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

General

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

B. NON-UTILITY ENERGY INFRASTRUCTURE SEGMENT

Bluewater and We Power are considered non-utility energy infrastructure operations, however, their facilities are shown in the regulated section. We Power owns and leases generating facilities to WE. We Power's share of the ERGS units and both PWGS units are being leased to WE under long-term leases. Bluewater provides natural gas storage and hub services to WE, WG, and WPS.

In January 2019, we completed the acquisition of an 80% ownership interest in Upstream, a wind generation facility located in Antelope County, Nebraska. The Upstream site consists of 81 wind turbines with a combined capacity of 202.5 MW. See Note 2, Acquisitions, for more information.

In December 2018, we completed the acquisition of an 80% ownership interest in Coyote Ridge, a wind generation facility under construction in Brookings County, South Dakota. Coyote Ridge is expected to be in service by the end of 2019. The Coyote Ridge site will consist of 39 wind turbines with a combined capacity of 97.5 MW. See Note 2, Acquisitions, for more information.

In August 2018, we completed the acquisition of an 80% ownership interest in Bishop Hill III, which consists of 53 wind turbines located in Henry County, Illinois with a total capacity of 132 MW. In December 2018, we acquired an additional 10% membership interest in this wind farm. See Note 2, Acquisitions, for more information.

C. CORPORATE AND OTHER

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

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

ITEM 3. LEGAL PROCEEDINGS

The following should be read in conjunction with Note 22, Commitments and Contingencies, and Note 24, Regulatory Environment, in this report for additional information on material legal proceedings and matters related to us and our subsidiaries.

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

Environmental Matters

Manlove Field Matter

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

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

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

Presque Isle Power Plant Matter

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

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

EXECUTIVE OFFICERS OF THE REGISTRANT

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

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

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

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

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

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

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

Scott J. Lauber.[(3)] Age 53.
- WEC Energy Group — Executive Vice President, Chief Financial Officer and Treasurer since October 2018. Executive Vice President and Chief Financial Officer from April 2016 to October 2018. Vice President and Treasurer from February 2013 to March 2016.
- WE — Executive Vice President, Chief Financial Officer and Treasurer since October 2018. Director since April 2016. Executive Vice President and Chief Financial Officer from April 2016 to October 2018. Vice President and Treasurer from February 2013 to March 2016.

Charles R. Matthews. Age 62.
- PELLC — President since June 2015.
- PGL — Director, President, and Chief Executive Officer since June 2015.
- NSG — Director, President, and Chief Executive Officer since June 2015.
- WE — Senior Vice President - Wholesale Energy and Fuels from January 2012 to June 2015.

Tom Metcalfe. Age 51.

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

Mary Beth Straka. Age 54.

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

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

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

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

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

PART II

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

Number of Common Shareholders

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

Common Stock Listing and Trading

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

Common Stock Dividends of WEC Energy Group

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

ITEM 6. SELECTED FINANCIAL DATA

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

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

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

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

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

CORPORATE DEVELOPMENTS

Introduction

We are a diversified holding company with natural gas and electric utility operations (serving customers in Wisconsin, Illinois, Michigan, and Minnesota), an approximately 60% equity ownership interest in American Transmission Company LLC (ATC) (a for-profit electric transmission company regulated by the FERC and certain state regulatory commissions), and non-utility energy infrastructure operations through We Power (which owns generation assets in Wisconsin), Bluewater (which owns underground natural gas storage facilities in Michigan), and a 90% ownership interest in Bishop Hill III (a wind generating facility in Illinois).

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

Corporate Strategy

Our goal is to continue to build and sustain long-term value for our shareholders and customers by focusing on the fundamentals of our business: reliability; operating efficiency; financial discipline; customer care; and safety.

Reshaping Our Generation Fleet

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

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

In December 2018, Wisconsin Electric Power Company (WE) received approval from the PSCW for two renewable energy pilot programs. The Solar Now pilot is expected to add 35 MW of solar to WE's portfolio, allowing commercial and industrial customers to site solar arrays on their property. The second program, the Dedicated Renewable Energy Resource pilot, would allow large commercial and industrial customers to access renewable resources that WE would operate, adding up to 150 MW of renewables to WE's portfolio, and allowing these larger customers to meet their sustainability and renewable energy goals.

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

Reliability

We have made significant reliability-related investments in recent years, and plan to continue strengthening and modernizing our generation fleet and distribution networks to further improve reliability. Our investments, coupled with our commitment to

operating efficiency and customer care, resulted in We Energies being recognized by PA Consulting Group, an independent consulting firm, as the most reliable utility in the Midwest for the eighth year in a row.

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

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

- The Peoples Gas Light and Coke Company continues to work on its Natural Gas System Modernization Program, which primarily involves replacing old cast and ductile iron pipes and facilities in Chicago's natural gas delivery system with modern polyethylene pipes to reinforce the long-term safety and reliability of the system.

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

Operating Efficiency

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

We continue to focus on integrating and improving business processes and consolidating our IT infrastructure across all of our companies. We expect these efforts to continue to drive operational efficiency and to put us in position to effectively support plans for future growth.

Financial Discipline

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

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

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

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

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

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

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

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

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

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

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

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

[3] Represents additional transmission expense associated with WE's flow through of tax benefits of its repair-related deferred tax liabilities starting in 2018, in accordance with a settlement agreement with the PSCW, to maintain certain regulatory asset balances at their December 31, 2017 levels. See Note 24, Regulatory Environment, for more information.

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

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

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

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

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

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

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

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

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

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

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

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.

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

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

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

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

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

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

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

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

2018 Compared with 2017

Natural Gas Utility Margins

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

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. See Item 1. Business – D. Regulation for more information on these commissions.

Regulated entities are allowed to defer certain costs that would otherwise be charged to expense if the regulated entity believes the recovery of those costs is probable. We record regulatory assets pursuant to specific orders or by a generic order issued by our regulators. Recovery of the deferred costs in future rates is subject to the review and approval by those regulators. We assume the risks and benefits of ultimate recovery of these items in future rates. If the recovery of the deferred costs, including those referenced below, is not approved by our regulators, the costs would be charged to income in the current period. In general, our regulatory assets are recovered over a period of between one to six years. Regulators can impose liabilities on a prospective basis for amounts previously collected from customers and for amounts that are expected to be refunded to customers. We record these items as regulatory liabilities. As of December 31, 2018, our regulatory assets were $3,855.8 million, and our regulatory liabilities were $4,288.4 million.

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

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

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

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

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

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

Commodity Costs

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

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

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

Weather

Our utilities' rates are based upon estimated normal temperatures. Our electric utility margins are unfavorably sensitive to below normal temperatures during the summer cooling season and, to some extent, to above normal temperatures during the winter heating season. Our natural gas utility margins are unfavorably sensitive to above normal temperatures during the winter heating season. PGL, NSG, and MERC have decoupling mechanisms in place that help reduce the impacts of weather. Decoupling mechanisms differ by state and allow utilities to recover or refund certain differences between actual and authorized margins. A

summary of actual weather information in our utilities' service territories during 2018, 2017, and 2016, as measured by degree days, may be found in Results of Operations.

Interest Rates

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

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

Marketable Securities Return

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

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

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

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

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

Economic Conditions

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

Inflation

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

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

Competitive Markets

Electric Utility Industry

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

Wisconsin

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

Michigan

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

Natural Gas Utility Industry

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

Wisconsin

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

Illinois

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

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.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

A. REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on the Financial Statements

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

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

Basis for Opinion

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

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

/s/DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
February 26, 2019

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

A. REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on Internal Control over Financial Reporting

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

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

Basis for Opinion

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

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

Definition and Limitations of Internal Control over Financial Reporting

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

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

/s/DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
February 26, 2019

B. CONSOLIDATED INCOME STATEMENTS

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

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

C. CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

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

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

D. CONSOLIDATED BALANCE SHEETS

At December 31 *(in millions, except share and per share amounts)*	2018	2017
Assets		
Current assets		
Cash and cash equivalents	**$ 84.5**	$ 38.9
Accounts receivable and unbilled revenues, net of reserves of $149.2 and $143.2, respectively	**1,280.9**	1,350.7
Materials, supplies, and inventories	**548.2**	539.0
Prepayments	**256.8**	210.0
Other	**77.2**	74.9
Current assets	**2,247.6**	2,213.5
Long-term assets		
Property, plant, and equipment, net of accumulated depreciation of $8,515.9 and $8,618.5, respectively	**22,000.9**	21,347.0
Regulatory assets	**3,805.1**	2,803.2
Equity investment in transmission affiliates	**1,665.3**	1,553.4
Goodwill	**3,052.8**	3,053.5
Other	**704.1**	619.9
Long-term assets	**31,228.2**	29,377.0
Total assets	**$ 33,475.8**	$ 31,590.5
Liabilities and Equity		
Current liabilities		
Short-term debt	**$ 1,440.1**	$ 1,444.6
Current portion of long-term debt	**365.0**	842.1
Accounts payable	**876.4**	859.9
Accrued payroll and benefits	**185.4**	169.1
Other	**464.8**	553.6
Current liabilities	**3,331.7**	3,869.3
Long-term liabilities		
Long-term debt	**9,994.0**	8,746.6
Deferred income taxes	**3,388.1**	2,999.8
Deferred revenue, net	**520.4**	543.3
Regulatory liabilities	**4,251.6**	3,718.6
Environmental remediation liabilities	**616.4**	617.4
Pension and OPEB obligations	**422.8**	397.4
Other	**1,108.1**	1,206.3
Long-term liabilities	**20,301.4**	18,229.4
Commitments and contingencies (Note 22)		
Common shareholders' equity		
Common stock – $0.01 par value; 325,000,000 shares authorized; 315,523,192 and 315,574,624 shares outstanding, respectively	**3.2**	3.2
Additional paid in capital	**4,250.1**	4,278.5
Retained earnings	**5,538.2**	5,176.8
Accumulated other comprehensive (loss) income	**(2.6)**	2.9
Common shareholders' equity	**9,788.9**	9,461.4
Preferred stock of subsidiary	**30.4**	30.4
Noncontrolling interests	**23.4**	—
Total liabilities and equity	**$ 33,475.8**	$ 31,590.5

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

E. CONSOLIDATED STATEMENTS OF CASH FLOWS

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

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

F. CONSOLIDATED STATEMENTS OF EQUITY

(in millions, expect per share amounts)	WEC Energy Group Common Shareholders' Equity							
	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.

G. CONSOLIDATED STATEMENTS OF CAPITALIZATION

At December 31 *(in millions)*			2018	2017
Common shareholder's equity (see accompanying statement)			**$ 9,788.9**	$ 9,461.4
Preferred stock of subsidiary (Note 11)			**30.4**	30.4
Long-term debt	**Interest Rate**	**Year Due**		
WEC Energy Group Senior Notes (unsecured)	1.65%	2018	**—**	300.0
	2.45%	2020	**400.0**	400.0
	3.375%	2021	**600.0**	—
	3.55%	2025	**500.0**	500.0
	6.20%	2033	**200.0**	200.0
WEC Energy Group Junior Notes (unsecured) [1]	4.853%	2067	**500.0**	500.0
WE Debentures (unsecured)	1.70%	2018	**—**	250.0
	4.25%	2019	**250.0**	250.0
	2.95%	2021	**300.0**	300.0
	3.10%	2025	**250.0**	250.0
	6.50%	2028	**150.0**	150.0
	5.625%	2033	**335.0**	335.0
	5.70%	2036	**300.0**	300.0
	3.65%	2042	**250.0**	250.0
	4.25%	2044	**250.0**	250.0
	4.30%	2045	**250.0**	250.0
	4.30%	2048	**300.0**	—
	6.875%	2095	**100.0**	100.0
WPS Senior Notes (unsecured)	1.65%	2018	**—**	250.0
	3.35%	2021	**400.0**	—
	6.08%	2028	**50.0**	50.0
	5.55%	2036	**125.0**	125.0
	3.671%	2042	**300.0**	300.0
	4.752%	2044	**450.0**	450.0
WG Debentures (unsecured)	3.53%	2025	**200.0**	200.0
	5.90%	2035	**90.0**	90.0
	3.71%	2046	**200.0**	200.0
PGL First and Refunding Mortgage Bonds (secured) [2]	8.00%	2018	**—**	5.0
	4.63%	2019	**75.0**	75.0
	3.87%	2028	**150.0**	—
	3.90%	2030	**50.0**	50.0
	1.875%	2033	**50.0**	50.0
	4.00%	2033	**50.0**	50.0
	3.98%	2042	**100.0**	100.0
	3.96%	2043	**220.0**	220.0
	4.21%	2044	**200.0**	200.0
	3.65%	2046	**50.0**	50.0
	3.65%	2046	**150.0**	150.0
	3.77%	2047	**100.0**	100.0
NSG First Mortgage Bonds (secured) [3]	3.43%	2027	**28.0**	28.0
	3.87%	2028	**50.0**	—
	3.96%	2043	**54.0**	54.0
MGU Senior Notes (unsecured)	3.11%	2027	**30.0**	30.0
	3.41%	2032	**30.0**	30.0
	4.01%	2047	**30.0**	30.0
MERC Senior Notes (unsecured)	3.11%	2027	**40.0**	40.0
	3.41%	2032	**40.0**	40.0
	4.01%	2047	**40.0**	40.0
Bluewater Gas Storage Senior Notes (unsecured)	3.76%	2019-2047	**122.7**	125.0

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.

H. NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

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

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

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

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

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

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

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

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

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

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

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

(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:

	Electric Utility Operating Revenues
(in millions)	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.

	December 31, 2017							
	Pension Plan Assets				OPEB Assets			
(in millions)	Level 1	Level 2	Level 3	Total	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:

	Private Equity and Real Estate		International Equity	
(in millions)	Pension	OPEB	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	**$ —**	**$ —**	**$ —**	**$ —**

	Private Equity and Real Estate		International Equity		U.S. Bonds
(in millions)	Pension	OPEB	Pension	OPEB	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.

	Utility Operations								
2018 *(in millions)*	**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.

	Utility Operations								
2017 *(in millions)*	**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.

	Utility Operations								
2016 *(in millions)*	**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.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Our management, with the participation of our principal executive officer and principal financial officer, has evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Based upon such evaluation, our principal executive officer and principal financial officer have concluded that, as of the end of such period, our disclosure controls and procedures are effective (i) in recording, processing, summarizing and reporting, on a timely basis, information required to be disclosed by us in the reports that we file or submit under the Exchange Act and (ii) to ensure that information required to be disclosed in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

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

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.

Report of Independent Registered Public Accounting Firm

For Deloitte & Touche LLP's Report of Independent Registered Public Accounting Firm, attesting to the effectiveness of our internal controls over financial reporting, see Section A of Item 8.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE OF THE REGISTRANT

The information under "Proposal 1: Election of Directors – Terms Expiring in 2020," "2019 Director Nominees for Election," "Section 16(a) Beneficial Ownership Reporting Compliance," "Information Related to the Annual Meeting – Stockholder Nominees and Proposals," and "Governance – Board Committees – Audit and Oversight," in our Definitive Proxy Statement on Schedule 14A to be filed with the SEC for our Annual Meeting of Shareholders to be held May 2, 2019 (the "2019 Annual Meeting Proxy Statement") is incorporated herein by reference. Also see "Executive Officers of the Registrant" in Part I of this report.

We have adopted a written code of ethics, referred to as our Code of Business Conduct, with which all of our directors, executive officers, and employees, including the principal executive officer, principal financial officer, and principal accounting officer, must comply with. We have posted our Code of Business Conduct on our website, www.wecenergygroup.com. We have not provided any waiver to the Code for any director, executive officer, or other employee. Any amendments to, or waivers for directors and executive officers from, the Code of Business Conduct will be disclosed on our website or in a current report on Form 8-K.

Our website, www.wecenergygroup.com, also contains our Corporate Governance Guidelines and the charters of our Audit and Oversight, Corporate Governance, and Compensation Committees.

Our Code of Business Conduct, Corporate Governance Guidelines, and committee charters are also available without charge to any shareholder of record or beneficial owner of our common stock by writing to the corporate secretary, Margaret C. Kelsey, at our principal business office, 231 West Michigan Street, P.O. Box 1331, Milwaukee, Wisconsin 53201.

ITEM 11. EXECUTIVE COMPENSATION

The information under "Compensation Discussion and Analysis," "Executive Compensation Tables," "Governance – Director Compensation," "Governance – Board Committees – Compensation," "Compensation Committee Report," "Pay Ratio Disclosure," "Risk Analysis of Compensation Policies and Practices," and "Certain Relationships and Related Transactions – Compensation Committee Interlocks and Insider Participation" in the 2019 Annual Meeting Proxy Statement is incorporated herein by reference.

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

The security ownership information called for by Item 12 of Form 10-K is incorporated herein by reference to this information included under "WEC Energy Group Common Stock Ownership" in the 2019 Annual Meeting Proxy Statement.

Equity Compensation Plan Information

The following table sets forth information about our equity compensation plans as of December 31, 2018:

Plan Type	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants, and Rights (a)	Weighted Average Exercise Price of Outstanding Options, Warrants, and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Shares Reflected in Column (a)) (c)
Equity Compensation Plans Approved by Security Holders	4,452,533	$ 48.86	26,900,950 *
Equity Compensation Plans Not Approved by Security Holders	N/A	N/A	N/A
Total	4,452,533	$ 48.86	26,900,950

* Includes shares available for future issuance under our Omnibus Stock Incentive Plan, all of which could be granted as awards of stock options, stock appreciation rights, performance units, restricted stock, or other stock based awards.

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

The information under "Proposal 1: Election of Directors – Terms Expiring in 2020 – Director Independence," "Governance – Board Committees," "Governance – Corporate Governance Framework – Related Party Transactions/Conflicts of Interest," and "Certain Relationships and Related Transactions" in the 2019 Annual Meeting Proxy Statement is incorporated herein by reference. A full description of the guidelines our Board uses to determine director independence is located in Appendix A of our Corporate Governance Guidelines, which can be found on the Corporate Governance section of our Company's website at www.wecenergygroup.com/govern/governance.htm.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information regarding the fees paid to, and services performed by, our independent auditors and the pre-approval policy of our audit and oversight committee under "Independent Auditors' Fees and Services" in the 2019 Annual Meeting Proxy Statement is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

1. Financial Statements and Reports of Independent Registered Public Accounting Firm Included in Part II of This Report

Description	Page in 10-K
Reports of Independent Registered Public Accounting Firm.	74
Consolidated Income Statements for the three years ended December 31, 2018, 2017, and 2016.	76
Consolidated Statements of Comprehensive Income for the three years ended December 31, 2018, 2017, and 2016.	77
Consolidated Balance Sheets at December 31, 2018 and 2017.	78
Consolidated Statements of Cash Flows for the three years ended December 31, 2018, 2017, and 2016.	79
Consolidated Statements of Equity for the three years ended December 31, 2018, 2017, and 2016.	80
Consolidated Statements of Capitalization at December 31, 2018 and 2017.	81
Notes to Consolidated Financial Statements.	83

2. Financial Statement Schedules Included in Part IV of This Report

Schedule I, Condensed Parent Company Financial Statements, including Income Statements, Statements of Comprehensive Income, and Statements of Cash Flows for the three years ended December 31, 2018, 2017, and 2016 and Balance Sheets as of December 31, 2018 and 2017.	148
Schedule II, Valuation and Qualifying Accounts, for the three years ended December 31, 2018, 2017, and 2016.	154

Other schedules are omitted because of the absence of conditions under which they are required or because the required information is given in the financial statements or notes thereto.

3. Exhibits and Exhibit Index

The following exhibits are filed or furnished with or incorporated by reference in the report with respect to WEC Energy Group, Inc. (File No. 001-09057). An asterisk (*) indicates incorporation by reference pursuant to Exchange Act Rule 12b-32. Each management contract and compensatory plan or arrangement required to be filed as an exhibit to this report pursuant to Item 15(b) of Form 10-K is identified below by two asterisks (**) following the description of the exhibit.

Number	Exhibit	
2	**Plan of Acquisition, Reorganization, Arrangement, Liquidation, or Succession**	
	2.1*	Agreement and Plan of Merger, dated as of June 22, 2014, by and between Wisconsin Energy Corporation (n/k/a WEC Energy Group, Inc.) and Integrys Energy Group, Inc. (Exhibit 2.1 to Wisconsin Energy Corporation's 06/22/14 Form 8-K.)
3	**Articles of Incorporation and By-laws**	
	3.1*	Restated Articles of Incorporation of WEC Energy Group, Inc., as amended effective May 21, 2012. (Exhibit 3.1 to Wisconsin Energy Corporation's 06/30/12 Form 10-Q.)

Number	Exhibit
	3.2* Articles of Amendment to the Restated Articles of Incorporation of WEC Energy Group, Inc., as amended. (Exhibit 3.1 to WEC Energy Group's 06/29/15 Form 8-K.)
	3.3* Bylaws of WEC Energy Group, Inc., as amended to October 20, 2016. (Exhibit 3.1 to WEC Energy Group's 10/20/16 Form 8-K.)
4	**Instruments defining the rights of security holders, including indentures**
	4.1* Reference is made to Article III of the Restated Articles of Incorporation and the Bylaws of WEC Energy Group, Inc. (See Exhibits 3.1 and 3.3 above.)
	4.2* Replacement Capital Covenant, dated May 11, 2007, by Wisconsin Energy Corporation for the benefit of certain debtholders named therein. (Exhibit 4.2 to Wisconsin Energy Corporation's 05/08/07 Form 8-K.)
	4.3* Amendment to Replacement Capital Covenant, dated as of June 29, 2015. (Exhibit 4.1 to Wisconsin Energy Corporation's 06/29/15 Form 8-K.)
	Indentures and Securities Resolutions:
	4.4* Indenture for Debt Securities of Wisconsin Electric Power Company (the "Wisconsin Electric Indenture"), dated December 1, 1995. (Exhibit (4)-1 under File No. 1-1245, WE's 12/31/95 Form 10-K.)
	4.5* Securities Resolution No. 1 of Wisconsin Electric under the Wisconsin Electric Indenture, dated December 5, 1995. (Exhibit (4)-2 under File No. 1-1245, WE's 12/31/95 Form 10-K.)
	4.6* Securities Resolution No. 3 of Wisconsin Electric under the Wisconsin Electric Indenture, dated May 27, 1998. (Exhibit (4)-1 under File No. 1-1245, WE's 06/30/98 Form 10-Q.)
	4.7* Securities Resolution No. 5 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of May 1, 2003. (Exhibit 4.47 filed with Post-Effective Amendment No. 1 to Wisconsin Electric's Registration Statement on Form S-3 (File No. 333-101054), filed May 6, 2003.)
	4.8* Securities Resolution No. 7 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of November 2, 2006. (Exhibit 4.1 under File No. 1-1245, WE's 11/02/06 Form 8-K.)
	4.9* Securities Resolution No. 10 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of December 8, 2009. (Exhibit 4.1 under File No. 1-1245, WE's 12/08/09 Form 8-K.)
	4.10* Securities Resolution No. 11 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of September 7, 2011. (Exhibit 4.1 under File No. 1-1245, WE's 09/07/11 Form 8-K.)
	4.11* Securities Resolution No. 12 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of December 5, 2012. (Exhibit 4.1 under File No. 1-1245, WE's 12/05/12 Form 8-K.)
	4.12* Securities Resolution No. 14 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of May 12, 2014. (Exhibit 4.1 under File No. 1-1245, WE's 05/12/14 Form 8-K.)
	4.13* Securities Resolution No. 15 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of May 14, 2015. (Exhibit 4.1 under File No. 1-1245, WE's 05/14/15 Form 8-K.)
	4.14* Securities Resolution No. 16 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of November 13, 2015. (Exhibit 4.1 under File No. 1-1245, WE's 11/13/15 Form 8-K.)
	4.15* Securities Resolution No. 17 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of October 1, 2018. (Exhibit 4.1 under File No. 1-1245, WE's 10/01/18 Form 8-K.)
	4.16* Indenture for Debt Securities of Wisconsin Energy Corporation (the "Wisconsin Energy Indenture"), dated as of March 15, 1999, between WEC Energy Group and The Bank of New York Mellon Trust Company, N.A. (as successor to First National Bank of Chicago), as Trustee. (Exhibit 4.46 to Wisconsin Energy Corporation's 03/25/99 Form 8-K.)

Number	Exhibit
4.17*	Securities Resolution No. 4 of Wisconsin Energy Corporation under the Wisconsin Energy Indenture, dated as of March 17, 2003. (Exhibit 4.12 filed with Post-Effective Amendment No. 1 to Wisconsin Energy Corporation's Registration Statement on Form S-3 (File No. 333-69592), filed March 20, 2003.)
4.18*	Securities Resolution No. 5 of Wisconsin Energy Corporation under the Wisconsin Energy Indenture, dated as of May 8, 2007. (Exhibit 4.1 to Wisconsin Energy Corporation's 05/08/07 Form 8-K.)
4.19*	Securities Resolution No. 6 of Wisconsin Energy Corporation under the Wisconsin Energy Indenture, dated as of June 4, 2015. (Exhibit 4.1 to Wisconsin Energy Corporation's 06/04/15 Form 8-K.)
4.20*	Securities Resolution No. 7 of WEC Energy Group under the Wisconsin Energy Indenture, dated as of June 4, 2018. (Exhibit 4.1 to WEC Energy Group's 06/04/18 Form 8-K.)
4.21*	Indenture, dated as of December 1, 1998, between Wisconsin Public Service Corporation ("WPS") and U.S. Bank National Association (successor to Firstar Bank Milwaukee, N.A., National Association) (Exhibit 4A to Form 8-K filed December 18, 1998) (File No. 1-3016).
4.22*	First Supplemental Indenture, dated as of December 1, 1998, between WPS and Firstar Bank Milwaukee, N.A., National Association (Exhibit 4C to Form 8-K filed December 18, 1998) (File No. 1-3016).
4.23*	Fifth Supplemental Indenture, dated as of December 1, 2006, by and between WPS and U.S. Bank National Association (Exhibit 4.1 to Form 8-K filed November 30, 2006) (File No. 1-3016).
4.24*	Ninth Supplemental Indenture, dated as of December 1, 2012, by and between WPS and U.S. Bank National Association (Exhibit 4.1 to Form 8-K filed November 29, 2012) (File No. 1-3016).
4.25*	Tenth Supplemental Indenture, dated as of November 1, 2013, by and between WPS and U.S. Bank National Association (Exhibit 4.1 to Form 8-K filed November 18, 2013) (File No. 1-3016).
4.26*	Twelfth Supplemental Indenture, dated as of November 21, 2018, by and between WPS and U.S. Bank National Association (Exhibit 4.1 to Form 8-K filed November 21, 2018) (File No. 1-3016).
	Certain agreements and instruments with respect to unregistered long-term debt not exceeding 10 percent of the total assets of the Registrant and its subsidiaries on a consolidated basis have been omitted as permitted by related instructions. The Registrant agrees pursuant to Item 601(b)(4) of Regulation S-K to furnish to the Securities and Exchange Commission, upon request, a copy of all such agreements and instruments.
10	**Material Contracts**
10.1	WEC Energy Group Supplemental Pension Plan, Amended and Restated Effective as of January 1, 2018.**
10.2	Legacy Wisconsin Energy Corporation Executive Deferred Compensation Plan, Amended and Restated as of January 1, 2018.**
10.3	WEC Energy Group Executive Deferred Compensation Plan, Amended and Restated Effective as of January 1, 2018.**
10.4*	Legacy Wisconsin Energy Corporation Directors' Deferred Compensation Plan, Amended and Restated Effective as of January 1, 2017. (Exhibit 10.4 to WEC Energy Group's 12/31/16 Form 10-K.)**
10.5*	WEC Energy Group Directors' Deferred Compensation Plan, Amended and Restated Effective as of January 1, 2017. (Exhibit 10.5 to WEC Energy Group's 12/31/16 Form 10-K.)**
10.6	WEC Energy Group Non-Qualified Retirement Savings Plan, Amended and Restated Effective as of January 1, 2018.**
10.7	WEC Energy Group Supplemental Long Term Disability Plan, Amended and Restated Effective as of January 1, 2017.**

Number	Exhibit
10.8	WEC Energy Group Short-Term Performance Plan, Amended and Restated Effective as of January 1, 2019.**
10.9*	Wisconsin Energy Corporation 2014 Rabbi Trust by and between Wisconsin Energy Corporation and The Northern Trust Company dated February 23, 2015, regarding the trust established to provide a source of funds to assist in meeting the liabilities under various nonqualified deferred compensation plans made between Wisconsin Energy Corporation or its subsidiaries and various plan participants. (Exhibit 10.13 to Wisconsin Energy Corporation's 12/31/14 Form 10K.)**
10.10*	Letter Agreement by and between WEC Energy Group, Inc. and Gale E. Klappa, dated as of December 7, 2017. (Exhibit 10.1 to WEC Energy Group's 12/08/17 Form 8-K.)**
10.11*	Terms and Conditions Governing Gale Klappa's and Frederick Kuester's Restricted Stock Awards Under the 1993 Omnibus Stock Incentive Plan. (Exhibit 10.2 to WEC Energy Group's 12/08/17 Form 8-K.)**
10.12*	Letter Agreement by and between Gale E. Klappa and WEC Energy Group, Inc., dated as of January 17, 2019. (Exhibit 10.1 to WEC Energy Group's 01/22/2019 Form 8-K.)**
10.13*	Amended and Restated Senior Officer Employment and Non-Compete Agreement between Wisconsin Energy Corporation and Allen L. Leverett, dated as of December 30, 2008. (Exhibit 10.26 to Wisconsin Energy Corporation's 12/31/08 Form 10-K.)**
10.14*	Terms of Employment for J. Patrick Keyes. (Exhibit 10.1 to Wisconsin Energy Corporation's 09/30/12 Form 10-Q.)**
10.15*	Letter Agreement by and between Wisconsin Energy Corporation and J. Patrick Keyes, dated as of December 20, 2010. (Exhibit 10.20 to Wisconsin Energy Corporation's 12/31/12 Form 10-K.)**
10.16*	Amendment to the Letter Agreement by and between Wisconsin Energy Corporation and J. Patrick Keyes, dated as of August 15, 2011. (Exhibit 10.21 to Wisconsin Energy Corporation's 12/31/12 Form 10-K.)**
10.17*	Letter Agreement by and between Wisconsin Energy Corporation and Robert Garvin, dated January 31, 2011. (Exhibit 10.1 to Wisconsin Energy Corporation's 03/31/11 Form 10-Q.)**
10.18*	Letter Agreement by and between Wisconsin Energy Corporation and Joseph Kevin Fletcher, dated as of August 17, 2011. (Exhibit 10.1 to Wisconsin Energy Corporation's 09/30/11 Form 10-Q.)**
10.19*	Letter Agreement by and between WEC Energy Group, Inc. and Margaret C. Kelsey, dated as of July 19, 2017. (Exhibit 10.1 to WEC Energy Group's 09/30/17 Form 10-Q.)**
10.20*	Consulting Agreement between Wisconsin Energy Corporation and Frederick D. Kuester, dated January 7, 2013 ("Kuester Consulting Agreement"). (Exhibit 10.19 to WEC Energy Group's 12/31/17 Form 10-K.)**
10.21*	Amendment to the Kuester Consulting Agreement, dated January 18, 2018. (Exhibit 10.20 to WEC Energy Group's 12/31/17 Form 10-K.)**
10.22*	Letter Agreement by and between WEC Energy Group, Inc. and Frederick D. Kuester, dated as of February 23, 2018. (Exhibit 10.1 to WEC Energy Group's 03/31/2018 Form 10-Q.)**
10.23*	WEC Energy Group 1993 Omnibus Stock Incentive Plan, Amended and Restated effective as of January 1, 2016 (Exhibit 10.19 to WEC Energy Group's 12/31/15 Form 10-K.)**
10.24*	Terms and Conditions Governing Non-Qualified Stock Option Award under the 1993 Omnibus Stock Incentive Plan. (Exhibit 10.1 to Wisconsin Energy Corporation's 09/30/07 Form 10-Q.)**
10.25*	2016 WEC Energy Group Terms and Conditions Governing Director Restricted Stock Awards under the 1993 Omnibus Stock Incentive Plan. (Exhibit 10.24 to WEC Energy Group's 12/31/15 Form 10-K.)**
10.26*	Director Restricted Stock Award Terms and Conditions under the 1993 Omnibus Stock Incentive Plan. (Exhibit 10.2 to WEC Energy Group's 12/01/16 Form 8-K.)**

Number	Exhibit
10.27*	WEC Energy Group Performance Unit Plan, amended and restated effective as of January 1, 2017. (Exhibit 10.1 to WEC Energy Group's 12/01/16 Form 8-K.)**
10.28*	2016 WEC Energy Group Restricted Stock Award Terms and Conditions governing awards under the 1993 Omnibus Stock Incentive Plan. (Exhibit 10.27 to WEC Energy Group's 12/31/15 Form 10-K.)**
10.29*	Wisconsin Energy Corporation Terms and Conditions Governing Non-Qualified Stock Option Award for option awards under the 1993 Omnibus Stock Incentive Plan, approved December 4, 2014. (Exhibit 10.3 to Wisconsin Energy Corporation's 12/04/14 Form 8-K.)**
10.30*	2016 WEC Energy Group Terms and Conditions Governing Non-Qualified Stock Option Award for option awards under the 1993 Omnibus Stock Incentive Plan. (Exhibit 10.29 to WEC Energy Group's 12/31/15 Form 10-K.)**
10.31*	Port Washington I Facility Lease Agreement between Port Washington Generating Station, LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of May 28, 2003. (Exhibit 10.7 to WE's 06/30/03 Form 10-Q (File No. 001-01245).)
10.32*	Port Washington II Facility Lease Agreement between Port Washington Generating Station, LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of May 28, 2003. (Exhibit 10.8 to WE's 06/30/03 Form 10-Q (File No. 001-01245).)
10.33*	Elm Road I Facility Lease Agreement between Elm Road Generating Station Supercritical, LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of November 9, 2004. (Exhibit 10.56 to Wisconsin Energy Corporation's 12/31/04 Form 10-K.)
10.34*	Elm Road II Facility Lease Agreement between Elm Road Generating Station Supercritical, LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of November 9, 2004. (Exhibit 10.57 to Wisconsin Energy Corporation's 12/31/04 Form 10-K.)
10.35*	Point Beach Nuclear Plant Power Purchase Agreement between FPL Energy Point Beach, LLC and Wisconsin Electric Power Company, dated as of December 19, 2006 (the "PPA"). (Exhibit 10.1 to Wisconsin Energy Corporation's 03/31/08 Form 10-Q.)
10.36*	Letter Agreement between Wisconsin Electric Power Company and FPL Energy Point Beach, LLC dated October 31, 2007, which amends the PPA. (Exhibit 10.45 to Wisconsin Energy Corporation's 12/31/07 Form 10-K.)
10.37*	Integrys Energy Group, Inc. Deferred Compensation Plan, as Amended and Restated Effective January 1, 2016. (Exhibit 10.1 to WEC Energy Group's 06/30/16 Form 10-Q.)**
10.38*	Integrys Energy Group, Inc. Pension Restoration and Supplemental Retirement Plan, as Amended and Restated Effective January 1, 2017. (Exhibit 10.1 to WEC Energy Group's 06/30/17 Form 10-Q.)**
10.39*	PELLC Directors Deferred Compensation Plan as amended and restated April 7, 2004. (Exhibit 10(a) under File No. 1-5540, PELLC's 06/30/04 Form 10-Q.)**
10.40*	Amended and Restated Trust under PELLC Directors Deferred Compensation Plan, Directors Stock and Option Plan, Executive Deferred Compensation Plan and Supplemental Retirement Benefit Plan, dated as of August 13, 2003. (Exhibit 10(a) under File No. 1-5540, PELLC's 09/30/03 Form 10-Q.)**
10.41*	Amendment Number One to the Amended and Restated Trust under PELLC Directors Deferred Compensation Plan, Directors Stock and Option Plan, Executive Deferred Compensation Plan and Supplemental Retirement Benefit Plan, dated as of July 24, 2006. (Exhibit 10(e) under File No. 1-5540, PELLC's 09/30/06 Form 10-Q.)**

Number	Exhibit	
21	**Subsidiaries of the registrant**	
	21.1	Subsidiaries of WEC Energy Group.
23	**Consents of experts and counsel**	
	23.1	Deloitte & Touche LLP – Milwaukee, WI, Consent of Independent Registered Public Accounting Firm for WEC Energy Group.
31	**Rule 13a-14(a) / 15d-14(a) Certifications**	
	31.1	Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
	31.2	Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	**Section 1350 Certifications**	
	32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
	32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101	**Interactive Data File**	

ITEM 16. FORM 10-K SUMMARY

None.

SCHEDULE I – CONDENSED
PARENT COMPANY FINANCIAL STATEMENTS
WEC ENERGY GROUP, INC. (PARENT COMPANY ONLY)

A. INCOME STATEMENTS

Year Ended December 31 *(in millions)*	**2018**	**2017**	**2016**
Operating expenses	**$ 5.0**	$ 6.0	$ 7.0
Equity in earnings of subsidiaries	**1,108.3**	1,234.7	996.5
Other income, net	**6.8**	2.1	2.7
Interest expense	**104.1**	82.0	90.0
Income before income taxes	**1,006.0**	1,148.8	902.2
Income tax benefit	**53.3**	54.9	36.8
Net income attributed to common shareholders	**$ 1,059.3**	$ 1,203.7	$ 939.0

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

B. STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31 *(in millions)*	2018	2017	2016
Net income attributed to common shareholders	**$ 1,059.3**	$ 1,203.7	$ 939.0
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 costs arising during the period, net of tax	**(0.9)**	(0.1)	(1.0)
Amortization of pension and OPEB costs included in net periodic benefit cost, net of tax	**0.2**	0.2	0.3
Cumulative effect adjustment from adoption of ASU 2018-02	**(0.3)**	—	—
Defined benefit plans, net	**(1.0)**	0.1	(0.7)
Other comprehensive (loss) income from subsidiaries, net of tax	**(2.8)**	1.2	0.3
Other comprehensive loss, net of tax	**(5.5)**	—	(1.7)
Comprehensive income attributed to common shareholders	**$ 1,053.8**	$ 1,203.7	$ 937.3

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

C. BALANCE SHEETS

At December 31 *(in millions)*	2018	2017
Assets		
Current assets		
Cash and cash equivalents	**$ 32.8**	$ 4.0
Accounts receivable from related parties	**4.0**	1.9
Notes receivable from related parties	**71.0**	64.1
Prepaid taxes	**—**	17.5
Other	**0.6**	0.6
Current assets	**108.4**	88.1
Long-term assets		
Investments in subsidiaries	**12,682.5**	12,101.9
Notes receivable from UMERC	**150.0**	50.0
Other	**31.8**	47.7
Long-term assets	**12,864.3**	12,199.6
Total assets	**$ 12,972.7**	$ 12,287.7
Liabilities and Equity		
Current liabilities		
Short-term debt	**$ 548.4**	$ 494.8
Current portion of long-term debt	**—**	300.0
Accounts payable to related parties	**7.7**	2.7
Notes payable to related parties	**398.9**	406.0
Other	**14.0**	8.9
Current liabilities	**969.0**	1,212.4
Long-term liabilities		
Long-term debt	**2,190.8**	1,592.3
Other	**24.0**	21.6
Long-term liabilities	**2,214.8**	1,613.9
Common shareholders' equity	**9,788.9**	9,461.4
Total liabilities and equity	**$ 12,972.7**	$ 12,287.7

The accompanying notes to Condensed Parent Company Financial Statements are an integral part of these financial statements.

D. STATEMENTS OF CASH FLOWS

Year Ended December 31 *(in millions)*	2018	2017	2016
Operating activities			
Net income attributed to common shareholders	**$ 1,059.3**	$ 1,203.7	$ 939.0
Reconciliation to cash provided by operating activities			
Equity income in subsidiaries, net of distributions	**(419.4)**	(686.1)	(271.1)
Deferred income taxes	**14.4**	89.5	23.2
Change in –			
Prepaid taxes	**17.5**	28.4	(47.6)
Other current assets	**(2.1)**	(0.1)	13.0
Accrued taxes	**3.6**	—	(75.6)
Other current liabilities	**5.7**	(1.9)	(5.6)
Other, net	**5.6**	0.9	6.3
Net cash provided by operating activities	**684.6**	634.4	581.6
Investing activities			
Acquisition of Bluewater	**—**	(226.0)	—
Capital contributions to subsidiaries	**(448.7)**	(173.4)	(55.8)
Return of capital from subsidiaries	**290.2**	—	9.0
Short-term notes receivable from related parties, net	**(6.9)**	167.8	46.8
Issuance of long-term notes receivable from UMERC	**(100.0)**	(50.0)	—
Purchase of subsidiary's common stock	**—**	—	(66.4)
Other, net	**6.4**	4.5	(0.4)
Net cash used in investing activities	**(259.0)**	(277.1)	(66.8)
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	**600.0**	—	—
Retirement of long-term debt	**(300.0)**	—	—
Change in short-term debt	**53.6**	173.0	13.9
Short-term notes payable to related parties, net	**(6.2)**	169.5	162.3
Other, net	**(3.6)**	—	0.2
Net cash used in financing activities	**(396.8)**	(354.5)	(514.9)
Net change in cash and cash equivalents	**28.8**	2.8	(0.1)
Cash and cash equivalents at beginning of year	**4.0**	1.2	1.3
Cash and cash equivalents at end of year	**$ 32.8**	$ 4.0	$ 1.2

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

SCHEDULE I – CONDENSED
PARENT COMPANY FINANCIAL STATEMENTS
WEC ENERGY GROUP, INC. (PARENT COMPANY ONLY)

E. NOTES TO PARENT COMPANY FINANCIAL STATEMENTS

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

For Parent Company only presentation, investments in subsidiaries are accounted for using the equity method. The condensed Parent Company financial statements and notes should be read in conjunction with the consolidated financial statements and notes of WEC Energy Group, Inc. appearing in this Annual Report on Form 10-K.

NOTE 2—CASH DIVIDENDS RECEIVED FROM SUBSIDIARIES

Dividends received from our subsidiaries during the years ended December 31 were as follows:

(in millions)	2018	2017	2016
WE	**$ 310.0**	$ 240.0	$ 455.0
We Power	**223.0**	181.0	188.9
ATC Holding	**105.8**	82.6	6.5
WG	**50.0**	45.0	75.0
Wisvest	**0.1**	—	—
Total	**$ 688.9**	$ 548.6	$ 725.4

In accordance with ASU 2016-15, on January 1, 2018, we retrospectively adopted the cumulative earnings approach for classifying distributions received from equity method investments on our statements of cash flows. Due to our adoption of this approach, We Power distributions of $9.0 million were reclassified from operating activities to a return of capital within investing activities on our statement of cash flows for the year ended December 31, 2016. For more information on ASU 2016-15 and the cumulative earnings approach, see Note 23, Supplemental Cash Flow Information, of WEC Energy Group, Inc. in this Annual Report on Form 10-K.

NOTE 3—LONG-TERM DEBT

The following table shows the future maturities of our long-term debt outstanding as of December 31, 2018:

(in millions)	
2020	**$ 400.0**
2021	**600.0**
Thereafter	**1,200.0**
Total	**$ 2,200.0**

WECC is our subsidiary and has $50.0 million of long-term notes outstanding. In a Support Agreement between WECC and us, we agreed to make sufficient liquid asset contributions to WECC to permit WECC to service its debt obligations as they become due.

NOTE 4—FAIR VALUE MEASUREMENTS

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

	2018		2017	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term notes receivable from UMERC	**$ 150.0**	**$ 145.5**	$ 50.0	$ 49.5
Long-term debt, including current portion	**2,190.8**	**2,132.8**	1,892.3	1,941.5

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

NOTE 5—SUPPLEMENTAL CASH FLOW INFORMATION

(in millions)	2018	2017	2016
Cash (paid) for interest	**$ (102.9)**	$ (82.5)	$ (89.6)
Cash received (paid) for income taxes, net	**85.9**	169.9	(62.9)
Significant non-cash equity transactions			
Issuance of short-term note receivable to Bluewater	**—**	115.0	—
Issuance of short-term note receivable to UMERC	**—**	40.5	—
Settlement of short-term note payable with Bostco	**—**	4.8	—
Settlement of short-term note payable with Wisvest	**0.9**	—	40.0

NOTE 6—SHORT-TERM NOTES RECEIVABLE FROM RELATED PARTIES

The following table shows our outstanding short-term notes receivable from related parties as of December 31:

(in millions)	2018	2017
UMERC	**$ 42.5**	$ 38.1
Wispark	**28.5**	26.0
Total	**$ 71.0**	$ 64.1

NOTE 7—SHORT-TERM NOTES PAYABLE TO RELATED PARTIES

The following table shows our outstanding short-term notes payable to related parties as of December 31:

(in millions)	2018	2017
Integrys	**$ 139.5**	$ 278.2
WBS	**123.5**	16.4
WECC	**110.3**	110.2
Bluewater Gas Storage	**25.6**	0.3
Wisvest	**—**	0.9
Total	**$ 398.9**	$ 406.0

SCHEDULE II
WEC ENERGY GROUP, INC.
VALUATION AND QUALIFYING ACCOUNTS

Allowance for Doubtful Accounts *(in millions)*	**Balance at Beginning of Period**	**Expense [1]**	**Deferral**	**Net Write-offs [2]**	**Balance at End of Period**
December 31, 2018	**$ 143.2**	**$ 94.7**	**$ (5.5)**	**$ (83.2)**	**$ 149.2**
December 31, 2017	108.0	96.7	16.4	(77.9)	143.2
December 31, 2016	113.3	87.4	(5.9)	(86.8)	108.0

(1) Net of recoveries.

(2) Represents amounts written off to the reserve, net of adjustments to regulatory assets.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

WEC ENERGY GROUP, INC.

By /s/ J. KEVIN FLETCHER

Date: February 26, 2019

J. Kevin Fletcher
Chief Executive Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

/s/ J. KEVIN FLETCHER	February 26, 2019
J. Kevin Fletcher, Chief Executive Officer and President and Director -- Principal Executive Officer	
/s/ SCOTT J. LAUBER	February 26, 2019
Scott J. Lauber, Senior Executive Vice President, Chief Financial Officer, and Treasurer -- Principal Financial Officer	
/s/ WILLIAM J. GUC	February 26, 2019
William J. Guc, Vice President and Controller -- Principal Accounting Officer	
/s/ GALE E. KLAPPA	February 26, 2019
Gale E. Klappa, Executive Chairman and Director	
/s/ JOHN F. BERGSTROM	February 26, 2019
John F. Bergstrom, Director	
/s/ BARBARA L. BOWLES	February 26, 2019
Barbara L. Bowles, Director	
/s/ WILLIAM J. BRODSKY	February 26, 2019
William J. Brodsky, Director	
/s/ ALBERT J. BUDNEY, JR.	February 26, 2019
Albert J. Budney, Jr., Director	
/s/ PATRICIA W. CHADWICK	February 26, 2019
Patricia W. Chadwick, Director	
/s/ CURT S. CULVER	February 26, 2019
Curt S. Culver, Director	
/s/ DANNY L. CUNNINGHAM	February 26, 2019
Danny L. Cunningham, Director	
/s/ WILLIAM M. FARROW, III	February 26, 2019
William M. Farrow, III, Director	
/s/ THOMAS J. FISCHER	February 26, 2019
Thomas J. Fischer, Director	
/s/ HENRY W. KNUEPPEL	February 26, 2019
Henry W. Knueppel, Director	
/s/ ALLEN L. LEVERETT	February 26, 2019
Allen L. Leverett, Director	
/s/ ULICE PAYNE, JR.	February 26, 2019
Ulice Payne, Jr., Director	
/s/ MARY ELLEN STANEK	February 26, 2019
Mary Ellen Stanek, Director	

Exhibit 21.1

WEC ENERGY GROUP, INC.
SUBSIDIARIES AS OF DECEMBER 31, 2018

The following table includes the subsidiaries of WEC Energy Group, a diversified holding company incorporated in the state of Wisconsin, as well as the percent of ownership, as of December 31, 2018:

Subsidiary *	State of Incorporation or Organization	Percent Ownership
ATC Holding LLC	Wisconsin	100%
American Transmission Company LLC	Wisconsin	60.31%
ATC Development Manager, Inc.	Delaware	74.73%
ATC Holdco, LLC	Delaware	75.17%
ATC Management Inc.	Wisconsin	60.32%
Bluewater Natural Gas Holding, LLC	Delaware	100%
BGS Kimball Gas Storage, LLC	Delaware	100%
Bluewater Gas Storage, LLC	Delaware	100%
Integrys Holding, Inc.	Wisconsin	100%
Michigan Gas Utilities Corporation	Delaware	100%
Minnesota Energy Resources Corporation	Delaware	100%
Peoples Energy, LLC	Delaware	100%
North Shore Gas Company	Illinois	100%
Peoples Energy Ventures, LLC	Delaware	100%
The Peoples Gas Light and Coke Company	Illinois	100%
Wisconsin Public Service Corporation	Wisconsin	100%
Wisconsin River Power Company	Wisconsin	50%
Wisconsin Valley Improvement Company	Wisconsin	27%
WPS Power Development, LLC	Wisconsin	100%
WPS Visions, Inc.	Wisconsin	100%
Upper Michigan Energy Resources Corporation	Michigan	100%
W.E. Power, LLC	Wisconsin	100%
Elm Road Generating Station Supercritical, LLC	Wisconsin	100%
Elm Road Services, LLC	Wisconsin	100%
Port Washington Generating Station, LLC	Wisconsin	100%
WEC Business Services LLC	Delaware	100%
WEC Infrastructure LLC	Delaware	100%
Bishop Hill Energy III Holdings LLC	Delaware	90%
Bishop Hill Energy III LLC	Delaware	100%
Coyote Ridge Wind, LLC	Oregon	80%
WEC Investments, LLC	Delaware	100%
Wisconsin Electric Power Company	Wisconsin	100%
Wisconsin Energy Capital Corporation	Wisconsin	100%
Wisconsin Gas LLC	Wisconsin	100%
Wispark LLC	Wisconsin	100%
Wisvest LLC	Wisconsin	100%

* Omits the names of certain subsidiaries, which if considered in the aggregate as a single subsidiary, would not constitute a "significant subsidiary" as of December 31, 2018. Indirectly owned subsidiaries are listed under the subsidiaries through which WEC Energy Group, Inc. holds ownership.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-221033 and 333-225349 on Form S-3 and Registration Statement Nos. 333-213589, 333-161151 and 333-177572 on Form S-8 of our reports dated February 26, 2019, relating to the consolidated financial statements and financial statement schedules of WEC Energy Group, Inc. and subsidiaries (the "Company"), and the effectiveness of the Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of the Company for the year ended December 31, 2018.

/s/DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
February 26, 2019

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

I, J. Kevin Fletcher, certify that:

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

Date: February 26, 2019

/s/ J. KEVIN FLETCHER

J. Kevin Fletcher
Chief Executive Officer and President
(Principal Executive Officer)

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

I, Scott J. Lauber, certify that:

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

Date: February 26, 2019

/s/ SCOTT J. LAUBER

Scott J. Lauber
Senior Executive Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

Exhibit 32.1

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

In connection with the Annual Report of WEC Energy Group, Inc. (the "Company") on Form 10-K for the period ended December 31, 2018, as filed with the Securities and Exchange Commission on February 26, 2019 (the "Report"), I, J. Kevin Fletcher, Chief Executive Officer and President, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

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

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

/s/ J. KEVIN FLETCHER

J. Kevin Fletcher
Chief Executive Officer and President
February 26, 2019

Exhibit 32.2

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

In connection with the Annual Report of WEC Energy Group, Inc. (the "Company") on Form 10-K for the period ended December 31, 2018, as filed with the Securities and Exchange Commission on February 26, 2019 (the "Report"), I, Scott J. Lauber, Senior Executive Vice President, Chief Financial Officer, and Treasurer of the Company, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

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

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

/s/ SCOTT J. LAUBER

Scott J. Lauber
Senior Executive Vice President, Chief Financial Officer, and Treasurer
February 26, 2019

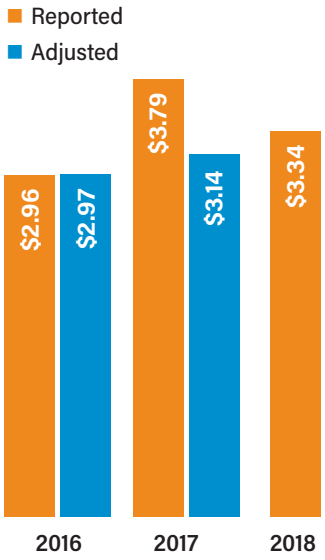
WEC Energy Group

Energized



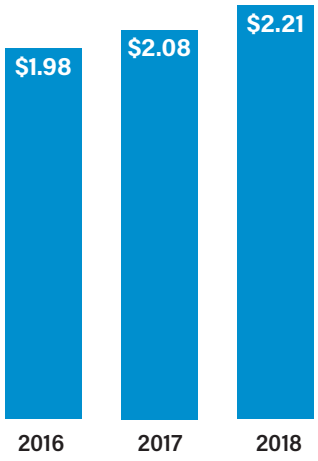
2018 Annual Report
Notice of 2019 Annual Meeting and Proxy Statement

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.

Dividends per share



Financial Snapshot

(In millions, except per share data and percentages)

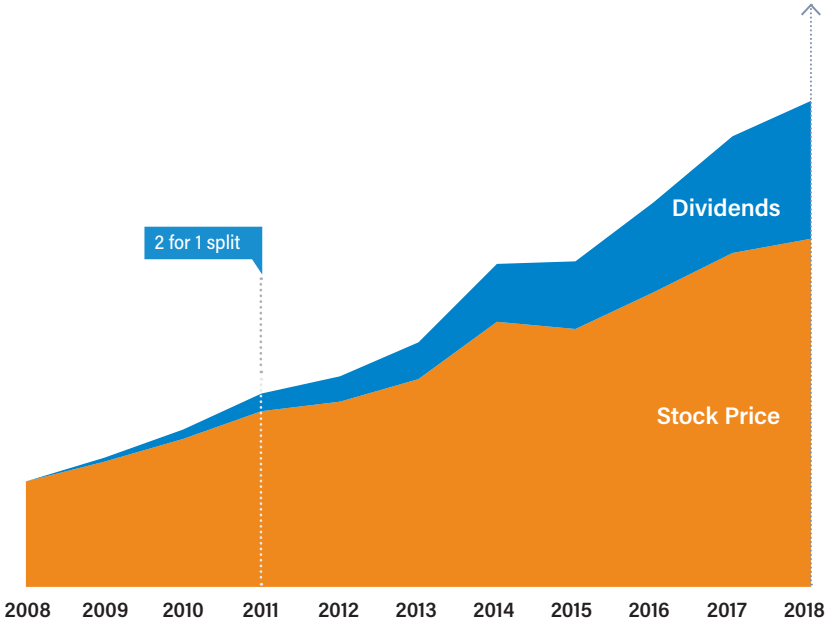
	2018	2017	Change
GAAP earnings*	$1,059.3	$1,203.7	
GAAP earnings per share*	$3.34	$3.79	
Adjusted earnings*	$1,059.3	$997.0	6.2%
Adjusted earnings per share*	$3.34	$3.14	6.4%
Dividends per share	$2.21	$2.08	6.3%
Dividend yield	3.2%	3.1%	
Diluted average shares outstanding	316.9	317.2	
GAAP return on 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.

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.

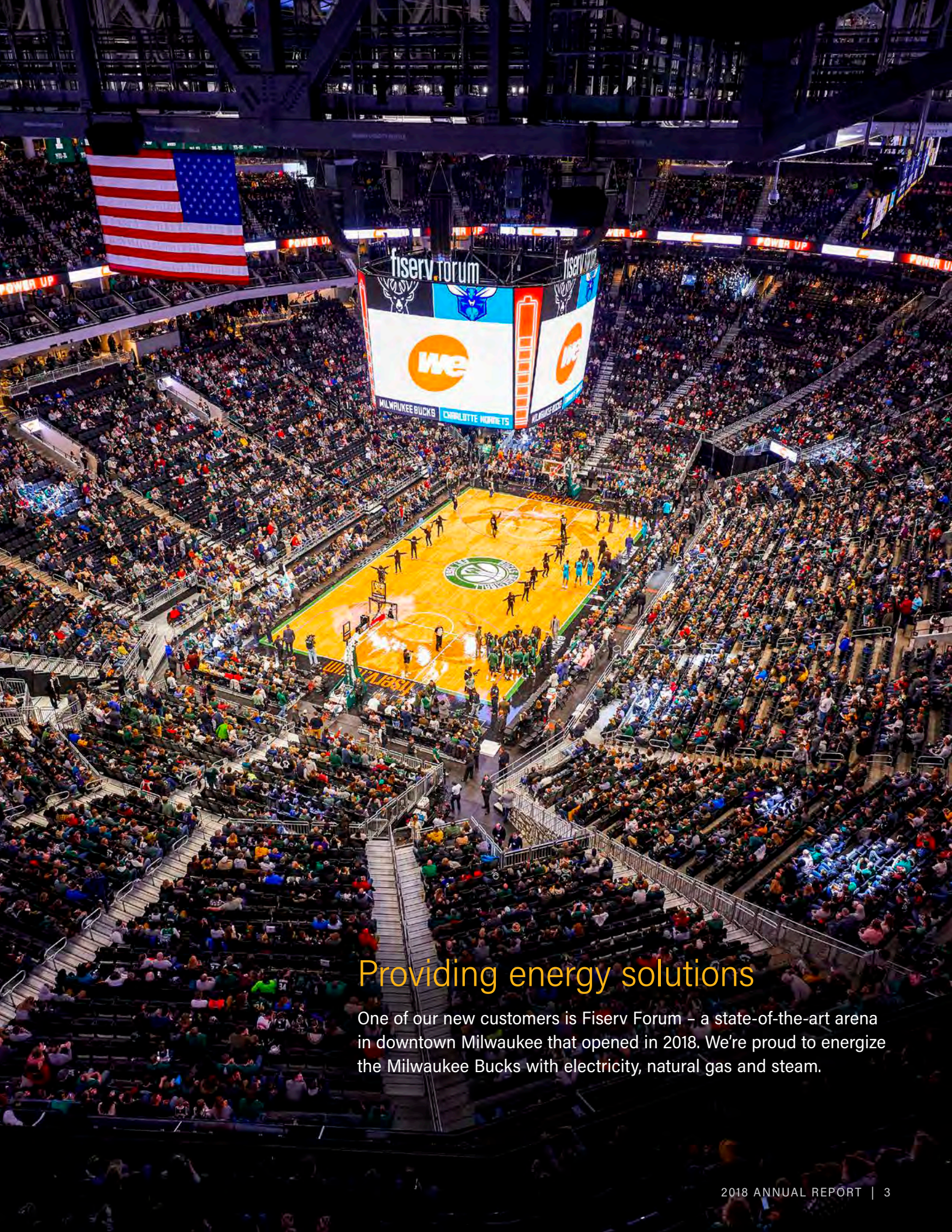
Sincerely,



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.

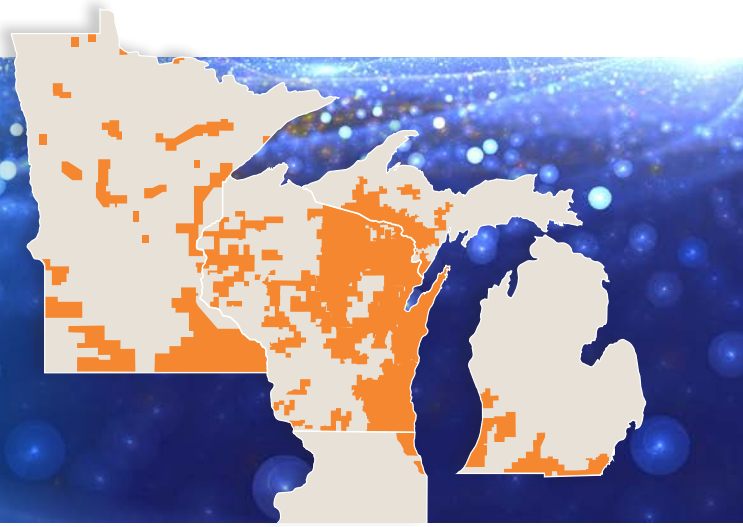
70,100 miles
of electric distribution

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:

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

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

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

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

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

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

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

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.

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

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

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

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

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

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

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

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

2018 Compared with 2017

Natural Gas Utility Margins

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

(in millions, expect per share amounts)	WEC Energy Group Common Shareholders' Equity							
	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.

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.

	December 31, 2017							
	Pension Plan Assets				OPEB Assets			
(in millions)	Level 1	Level 2	Level 3	Total	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:

	Private Equity and Real Estate		International Equity	
(in millions)	Pension	OPEB	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	**$ —**	**$ —**	**$ —**	**$ —**

	Private Equity and Real Estate		International Equity		U.S. Bonds
(in millions)	Pension	OPEB	Pension	OPEB	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.

	Utility Operations								
2018 *(in millions)*	**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.

	Utility Operations								
2017 *(in millions)*	**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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USA

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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.

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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:

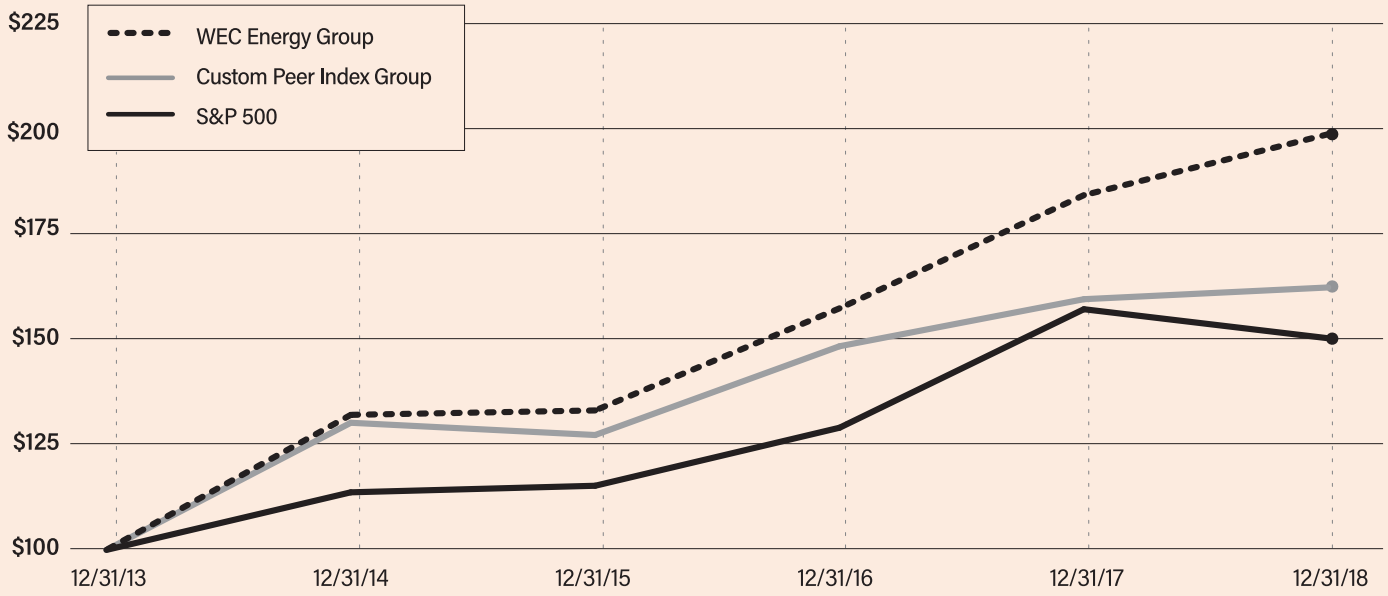
- WEC Energy Group common stock;
- a Custom Peer Group Index; and
- the Standard & Poor's 500 Index ("S&P 500").

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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WEC Energy Group

NOTICE OF 2019 ANNUAL MEETING AND PROXY STATEMENT

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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.

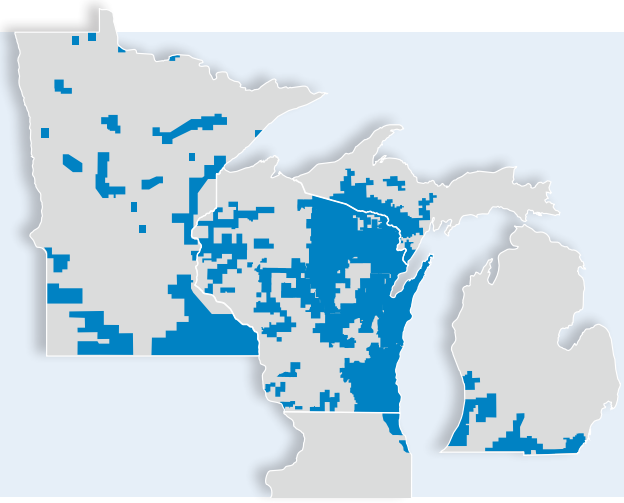
70,100 miles
of electric distribution

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.

In 2018, PA Consulting Group named We Energies best in the Midwest for the eighth year in a row for keeping the lights on for our customers.

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.

Dear Fellow Stockholders,

On behalf of our Board of Directors, I want to thank you for your investment in WEC Energy Group. As we prepare for our 2019 Annual Meeting of Stockholders, I ask for your support of the three proposals presented in this proxy statement. As you review each of these matters, please consider the following highlights from 2018, all of which demonstrate our commitment to applying strong corporate governance principles, while actively engaging in oversight of the Company's strategy, financial and operational performance, risk management, and executive leadership.

Strategy

Throughout 2018, the Board engaged in substantive discussions with management about WEC Energy Group's long-term strategy. Strategies must be evaluated in appropriate context, and in our case, we actively considered the many risks and opportunities facing the utility sector, including new technologies, customer preferences, commodity prices, energy resiliency efforts, climate change, cyber-security, and evolving shareholder engagement on environmental, social and governance initiatives.

Examples of strategic areas on which the Board provided critical oversight and input in 2018 include:

- WEC Energy Group's long-term goal to reduce carbon dioxide emissions by approximately 80 percent below 2005 levels by 2050;
- Reshaping the Company's generation fleet by balancing the need for energy resilience and fuel diversity with customer preferences and environmental objectives;
- Investment in renewable energy projects that will add carbon-free resources to our generating fleet, and others that bolster our energy infrastructure segment;
- Capital spending for projects centered on upgrading reliability, customer service, and information technology systems; and
- Regulatory and legislative priorities at the state and federal levels, from tax reform to climate change.

Management Succession Planning

In October 2017, our Company's then-CEO, Allen Leverett, suffered a stroke, following which the Board activated its executive succession plan. I stepped in as CEO during Mr. Leverett's recovery. Having served in that role from 2004 to 2016, the Board felt confident that my understanding of the Company -- and its operations, employees and investors -- would provide strong continuity as the Company continued to execute its short- and long-term plans.

Management succession was a clear focus in 2018. After Mr. Leverett's resignation as an officer of the Company, the Board appointed Kevin Fletcher, initially to serve as President of WEC Energy Group, followed by his transition into the added roles of CEO and a member of the Board of Directors, effective February 1, 2019. Mr. Fletcher has more than 40 years of experience in the energy industry, and the Board has the utmost confidence in his leadership capabilities. His deep experience in customer service and operations, combined with his previous responsibility for the operational and financial performance of all of the Company's utility subsidiaries, will enable him to contribute valuable Company and industry insights as a member of the Board.

In addition to appointing Mr. Fletcher to his new roles, the Board also appointed me to the position of Executive Chairman, and approved the creation of the Office of the Chair, solidifying a strong and seasoned leadership team. The Board believes this structure is appropriate to continue the smooth transition in leadership following Mr. Leverett's resignation as an active employee.

Financial and Operational Performance

By nearly every meaningful metric, 2018 was a record year for WEC Energy Group, and the Board was fully engaged in its oversight capacity throughout. Here are some results the Board believes are particularly noteworthy:

- Record earnings from operations and solid dividend growth;
- More cash returned to stockholders than any other year in Company history;
- Recognition as "most reliable" electric utility in the region and number one in the country for customer satisfaction among key accounts;
- Highest spending with diverse suppliers in Company history;
- Closure of nearly 1,500 megawatts of older, less efficient, coal-fired generation, reducing operating and maintenance costs by approximately $50 million annually;
- Increased dividend for 16th consecutive year (2004-2019); and
- Eleven all-time trading highs for WEC common stock.

This exceptional performance links directly to the Company's executive compensation structure and components, further demonstrating that our compensation program supports our annual and multi-year strategy. Our Board takes seriously its responsibility to ensure that executives truly are paid for performance in measurable, transparent, and meaningful ways.

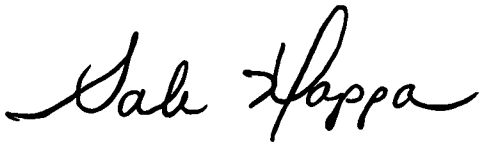
Board Composition and Refreshment

The Board is able to carry out its fiduciary obligations to our stockholders because of the combined strength, diversity, and dedication of its individual members. Just as the Board focused considerable attention during 2018 on management succession, the Board continued to move forward with thoughtful refreshment.

Two new, independent directors joined our Board over the past 15 months. This provided a transition period as two highly experienced directors will complete their service on the Board at the 2019 Annual Meeting. We expect refreshment to continue, as five additional independent directors are scheduled to complete their service over the next two years.

We are committed to ensuring that the WEC Energy Group Board of Directors continues to be comprised of at least a two-thirds majority of independent directors, and that the Board as a whole remains significantly diverse, as it is today.

As always, on behalf of the Board, I invite your engagement and appreciate your support.



Gale E. Klappa
Executive Chairman

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Notice of 2019 Annual Meeting of Stockholders

We are pleased to invite you to join our Board of Directors and senior leadership at WEC Energy Group's 2019 Annual Meeting of Stockholders.

When and Where

Thursday, May 2, 2019, 10:00 a.m., Central time
Concordia University Wisconsin
R. John Buuck Field House
12800 North Lake Shore Drive
Mequon, WI 53097

Items of Business

1. Elect thirteen directors for terms expiring in 2020.
2. Provide advisory vote to approve compensation of the named executive officers.
3. Ratify Deloitte & Touche LLP as independent auditors for 2019.
4. Consider any other matters that may properly come before the meeting.

Record Date

The Board of Directors set February 21, 2019 as the record date for the meeting. This means that our stockholders as of the close of business on that date are entitled to receive this notice of the meeting and to vote at the meeting. On the record date, there were 315,450,338 shares of common stock of WEC Energy Group, Inc. issued and outstanding and entitled to vote at the meeting.

Meeting Attendance Information

If you plan to attend the Annual Meeting in person, you must pre-register and present photo identification at the door. See page P-76 for information about the location, format, and how to register to attend the meeting. Regardless of whether you plan to attend, please take a moment to vote your Proxy.

If you are unable to attend, you may view a live webcast on our website at www.wecenergygroup.com/invest/annualmtg.htm.



Margaret C. Kelsey
Executive Vice President,
General Counsel and Corporate Secretary
March 21, 2019

Voting Information

Please follow the instructions on your Notice Regarding the Availability of Proxy Materials, proxy card, or the information forwarded to you by your bank or broker, as applicable. The internet and telephone voting facilities will close at 10:59 p.m. Central time, on Wednesday, May 1, 2019.

Registered Stockholders of Record

You may vote using one of the following voting methods. Please make sure you have your proxy card in hand and follow the instructions.

ONLINE

Visit www.investorvote.com

or scan the QR code with your smart phone

BY PHONE

Call toll-free 800-652-8683

BY MAIL

Sign, date and return your proxy card

Stockholders who beneficially hold shares in street name through an intermediary on this date must obtain a legal proxy from their broker, bank or other nominee granting the right to vote.

All stockholders of record may vote in person at the meeting. Beneficial owners may vote in person at the meeting if they have a legal proxy, as described on page P-74.

If you receive paper copies of the proxy materials, please consider signing up to receive them electronically in the future by following the instructions contained on page P-76. By delivering our proxy materials electronically, we can provide our stockholders with the information they need in a more cost-effective and timely manner.

Important Notice Regarding the Availability of Proxy Materials for the Stockholder Meeting to Be Held on May 2, 2019 — The Proxy Statement and 2018 Annual Report are available at www.envisionreports.com/wec.

PROXY SUMMARY

This summary is intended to highlight certain information found within this proxy statement. This summary does not contain all of the information that you should consider. Please read the entire proxy statement before voting. Additional information regarding WEC Energy Group, Inc.'s (the "Company") 2018 performance can be found in the Company's Annual Report on Form 10-K for the year ended December 31, 2018.



Election of 13 Directors

The Board recommends a vote FOR each nominee listed below.

- Strong corporate governance practices consistently recognized with strong governance ratings.
- All candidates are highly regarded executives who possess strong integrity.
- Slate of candidates embodies diversity of knowledge, skills, experiences, gender, ethnicity, tenure and maturity.

See **pages P16-P22** for more information.

Name	Professional Principal Experience	Age	Director Since	Indep.
Barbara L. Bowles (Presiding Independent Director)	Retired Vice Chair, Profit Investment Management	71	1998	Yes
Albert J. Budney, Jr.	Retired President, Niagara Mohawk Holdings, Inc.	71	2015	Yes
Patricia W. Chadwick	President, Ravengate Partners, LLC	70	2006	Yes
Curt S. Culver	Non-Executive Chairman, MGIC Investment Corporation	66	2004	Yes
Danny L. Cunningham	Retired Partner and Chief Risk Officer, Deloitte & Touche LLP	63	2018	Yes
William M. Farrow III	Chairman, CEO and owner, Winston and Wolfe LLC	63	2018	Yes
Thomas J. Fischer	Principal, Fischer Financial Consulting LLC	71	2005	Yes
J. Kevin Fletcher	President and CEO, WEC Energy Group, Inc.	60	2019	No
Gale E. Klappa	Executive Chairman of the Board, WEC Energy Group, Inc.	68	2003	No
Henry W. Knueppel	Retired Chairman and CEO, Regal Beloit Corporation	70	2013	Yes
Allen L. Leverett	Former CEO and President, WEC Energy Group, Inc.	52	2016	No
Ulice Payne, Jr.	Managing Member, Addison-Clifton, LLC	63	2003	Yes
Mary Ellen Stanek	Managing Director & Director of Asset Management, Baird Financial Group	62	2012	Yes

Directors John Bergstrom and William Brodsky will complete their service as directors in 2019 and thus are not serving as nominees for election at the 2019 Annual Meeting. The Company sincerely thanks them for their many important contributions, leadership and years of dedicated service. Mr. Brodsky currently serves as a member of the Finance Committee. Mr. Bergstrom currently chairs the Compensation Committee and is a member of the Audit and Oversight Committee; the Board is finalizing its plan for appointing a new Compensation Committee Chair. See pages P29-P31 for more information on committee assignments.

BOARD COMPOSITION

Through its ongoing succession planning process, the Board seeks to maintain a composition of directors that collectively possess the skills and qualifications to provide effective oversight of the Company's strategic initiatives, financial and operational performance, and enterprise risks.

The 2019 director nominees are highly regarded leaders who possess strong integrity, and embody a diversity of knowledge, skills, experiences, gender, ethnicity, tenure, and maturity to effectively carry out the Board's oversight duties and responsibilities on behalf of the Company's stockholders and other stakeholders.

Director nominees by the numbers

(based upon 13 members)

10 Director nominees are **independent**

9 Director nominees are **current** or **former CEOs**

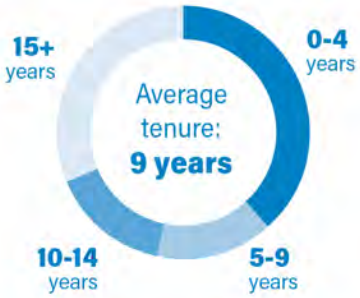
5 of 5 Director nominees on the Audit Committee are **financial experts**



3 Director nominees are **women**

3 Director nominees are **African American**

BALANCED TENURE



7 new directors since 2015

5 directors reach retirement age over the next 2 years

CORE COMPETENCIES – INTERMEDIATE TO ADVANCED KNOWLEDGE*

- Audit/Financial Planning
- CEO/Senior Leadership
- Corporate Governance
- Financial Strategy/Investment
- Risk Management

100% of directors

- Environment/CSR Matters
- Government/Public Policy
- Knowledge of Company's Industry
- Regulated Industry Knowledge
- Strategic Planning
- Talent Management/Exec Comp
- Technology/Security

> 75% of directors

* As reported by individual directors; see page P-15 for more information.

GOVERNANCE BEST PRACTICES

- Annual election of directors since 2005
- Ongoing Board succession planning
- Annual Board and committee evaluations
- Regular continuing education programs presented by internal and third-party experts
- Stock ownership requirements

INDEPENDENT BOARD AND COMMITTEES

- 10 of 13 independent directors
- Independent presiding director has specified duties
- Fully independent committee membership, except for the Executive Committee
- Executive sessions without management scheduled at each regular Board and committee meeting

ADVANCED SHAREHOLDER RIGHTS

- Majority vote standard for uncontested elections
- Bylaws include proxy access provision
- One-share, one-vote standard
- Special meeting provisions

PROPOSAL 2

Advisory Vote to Approve Compensation of the Named Executive Officers

The Board recommends a vote FOR the advisory vote on Executive Compensation.

- Our compensation program focuses on key Company results (financial, safety, customer satisfaction, diversity) that are aligned with our strategic goals.
- A substantial portion of compensation is at risk and tied to Company performance.
- The compensation program has a long-term orientation aligned with stockholder interests.

A comprehensive discussion of our executive compensation program, "Compensation Discussion and Analysis," begins on page P-35 of the Proxy Statement.

Our Business Performance

WEC Energy Group continued to achieve solid financial and operational results in 2018 while maintaining focus on the fundamentals - reliability, operating efficiency, financial discipline, customer care, and safety. As a result, the Company was able to deliver continued long-term value for our stockholders and customers.

FINANCIAL PERFORMANCE

Authorized Rate of Return
Each of our regulated utility subsidiaries earned its allowed rate of return in 2018

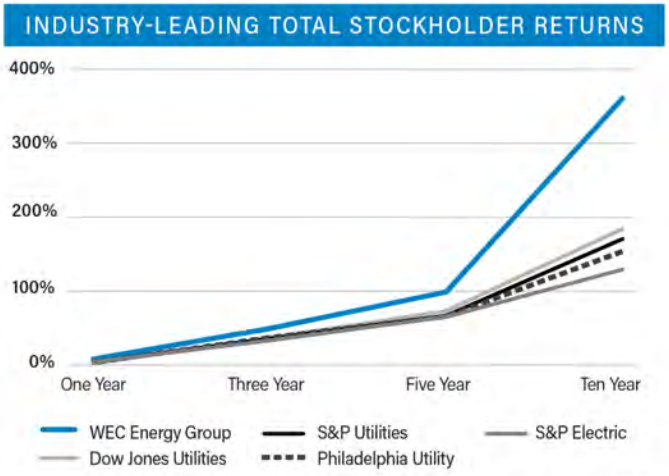


STOCKHOLDER RETURNS



76 consecutive years of delivering quarterly dividends (1942-2018)

16 consecutive years of dividend **increases** (2004-2019)



Source: Bloomberg; assumes all dividends are reinvested and returns are compounded daily.
See also the Five-Year Cumulative Return chart on page P-37.

NOTABLE ACHIEVEMENTS

WEC Energy Group named among 100 Best Corporate Citizens
Corporate Responsibility Magazine

WEC Energy Group presented with the 2018 Emergency Assistance Award
Edison Electric Institute

We Energies named most reliable utility in the Midwest for the eighth consecutive year
PA Consulting

We Energies named Veteran Friendly Workplace of the Year
USO Wisconsin

Our Executive Compensation Program

The Compensation Committee routinely evaluates the executive compensation program to ensure that it is competitive with respect to attracting and retaining key talent, linked to our financial and operational performance objectives, and aligned with industry best practices based upon input from stockholders and our compensation consultant. The Committee also takes into account prior say-on-pay results.

Best practices in executive compensation

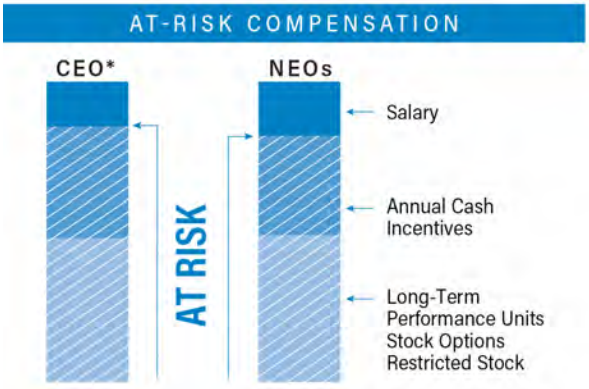
- Aligned with long-term performance and business strategy
- Includes short- and long-term metrics, cash and equity; substantial portion at risk
- Annual say-on-pay advisory vote
- Independent compensation consultant
- Meaningful stock ownership requirements
- Clawback policy
- Anti-hedging and anti-pledging policy

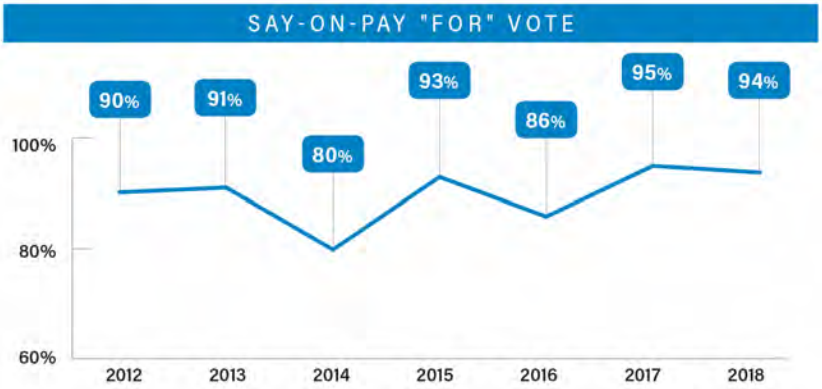
Compensation program links pay to performance

The executive compensation program has been designed so that total direct compensation ("TDC") is strongly tied to the achievement of our short-term and long-term goals. A substantial portion of pay is "at risk" and, generally, the value will only be realized upon a strong overall corporate performance.

	Salary	Annual Incentive	Performance Unit Plan	Stock Options and Restricted Stock
When Granted	Reviewed Annually			
Performance Type	Short-Term		Long-Term	
Award Type	Cash		Equity*	
Performance Period	Ongoing	1 year	3 Years	1 to 3 Year Vesting
How Payout is Determined	Role; responsibilities; market data; committee judgment	Formulaic: • Financial (EPS, cash flow, utility net income) • Operational (safety, customer satisfaction, diversity)	Formulaic: • TSR • Authorized ROE	Formulaic: Stock price performance

* Performance units are settled in cash.





* Based upon metrics for Gale Klappa.

Approximately 85% of our CEO's TDC, and an average of 82% of the other NEOs' TDC, is tied to Company performance and not guaranteed.

We maintain a largely consistent approach to our compensation program from year to year, while also responding to stockholder feedback. Historically, this has resulted in favorable approval ratings of our annual advisory say-on-pay proposal.

PROPOSAL 3

Ratification of Deloitte & Touche LLP as Independent Auditors for 2019

The Board recommends a vote FOR ratification of Deloitte & Touche LLP as independent auditors for 2019

- The Audit Committee annually evaluates the performance of Deloitte & Touche LLP and confirms that retention is in the best interests of the Company and its stockholders.
- Deloitte & Touche LLP is an independent firm with significant industry and financial reporting expertise, and fees that are appropriate for the size and scope of the Company.

See **pages P69-P71** for more information.

PROXY STATEMENT

This proxy statement is being furnished to stockholders beginning on or about March 21, 2019, in connection with the solicitation of proxies by the WEC Energy Group, Inc. ("WEC Energy Group" or the "Company") Board of Directors (the "Board") to be used at the Annual Meeting of Stockholders on Thursday, May 2, 2019 (the "Meeting") at 10:00 a.m., Central time, at Concordia University Wisconsin in the R. John Buuck Field House located at 12800 North Lake Shore Drive, Mequon, Wisconsin 53097, and at all adjournments or postponements of the Meeting, for the purposes listed in the Notice of 2019 Annual Meeting of Stockholders.

PROPOSAL 1: ELECTION OF DIRECTORS – TERMS EXPIRING IN 2020

WEC Energy Group's bylaws require each director to be elected annually to hold office for a one-year term. This is an uncontested election; therefore, our majority vote standard for election of directors will apply. Under this standard, the director nominees will be elected only if the number of votes cast favoring such nominee's election exceeds the number of votes cast opposing that nominee's election, as long as a quorum is present. Therefore, presuming a quorum is present, shares not voted, whether by broker non-vote, abstention, or otherwise, have no effect in the election of directors. Proxies may not be voted for more than 13 persons in the election of directors.

Acting on the recommendation of the Corporate Governance Committee, the Board's nominees for election are:

Barbara L. Bowles	**J. Kevin Fletcher**
Albert J. Budney, Jr.	**Gale E. Klappa**
Patricia W. Chadwick	**Henry W. Knueppel**
Curt S. Culver	**Allen L. Leverett**
Danny L. Cunningham	**Ulice Payne, Jr.**
William M. Farrow III	**Mary Ellen Stanek**
Thomas J. Fischer	

- Each nominee has consented to being nominated and to serve if elected. In the unlikely event that any nominee becomes unable to serve for any reason, the proxies will be voted for a substitute nominee selected by the Board upon the recommendation of the Corporate Governance Committee of the Board.
- Directors John F. Bergstrom and William J. Brodsky complete their service as directors in 2019 and thus will not serve as nominees for re-election at the 2019 annual meeting of stockholders. The Company sincerely thanks them for their many important contributions, leadership and years of dedicated service.

In selecting the 2019 director nominees, the Corporate Governance Committee and the Board determined that the candidates collectively embody a wide body of characteristics germane to executing the duties of the Board, including the general criteria, qualifications, diversity, and independence reported below, and which are described in more detail for each director in his/her respective biographies found under the heading, "2019 Director Nominees for Election."

The Board of Directors recommends that you vote "FOR" all of the director nominees.

DIRECTOR NOMINATION AND EVALUATION PROCESS

Nomination Process

Candidates for director nomination may be proposed in a number of ways, including by stockholders, the Corporate Governance Committee, and other members of the Board. The Corporate Governance Committee may pay a third party to identify qualified candidates; however, no such firm was engaged with respect to the nominees listed in this proxy statement.

The Corporate Governance Committee will consider director candidates recommended by stockholders provided that the stockholders submitting recommendations comply with requirements and procedures set forth in our bylaws. Stockholders may also nominate director candidates by following the procedures outlined on P-78. No formal stockholder nominations or recommendations for director candidates were received in connection with the 2019 Annual Meeting.

Evaluation Process

The Corporate Governance Committee evaluates director candidates, including those proposed by stockholders, through the lens of its ongoing director succession planning process, whereby the Corporate Governance Committee ensures that the Board is composed of directors who embody certain minimum criteria, and who, as a group, have the skills and experiences to effectively oversee management's strategy for operating in a complex industry while performing their fiduciary obligations.

When a person is initially identified as a potential candidate, the Corporate Governance Committee may collect and review publicly available information regarding the person to assess whether that person should be considered further. If the Corporate Governance Committee determines that the candidate warrants further consideration, the chair or another member of the Board of Directors contacts the person. Generally, if the person expresses a willingness to be considered and to serve on the Board, the Corporate Governance Committee requests additional information from the candidate, reviews the person's accomplishments and qualifications, and conducts one or more interviews with the candidate. In certain instances, Corporate Governance Committee members may contact one or more references provided by the candidate, or may contact other members of the business community or other persons who may have greater firsthand knowledge of the candidate. The Committee will utilize third parties if and as needed to assist with these activities. As a final step, the candidate interviews with members of the Board, following which the Corporate Governance Committee will propose a recommendation regarding nomination to the Board for its discussion and final determination.

Director Term Limits

The Board does not believe it is appropriate or necessary to limit the number of terms a director may serve. The Board values the participation and insight of directors who have developed an increased understanding of the governance of the Company and the specific issues it faces doing business in a complex, regulated industry, as well as those directors who bring fresh and varied perspectives, resulting in a Board with a balanced tenure.

DIRECTOR QUALIFICATIONS

The Corporate Governance Committee and the Board evaluate director nominees in light of the Board's current members, with the goal of recommending nominees with diverse backgrounds and experiences who, together with the current directors, can best perpetuate the success of WEC Energy Group's business and represent stockholder interests. By adhering to a philosophy whereby director nominees are evaluated on the basis of certain minimum qualifications, Board diversity, and core competencies, the Board is able to attract director candidates that bring a broad range of perspectives and experiences, and who will effectively contribute to and complement the Board.

Key factors considered in recommending the 2019 director nominees are listed below:

- To be eligible for consideration, the Board believes that any proposed candidate must demonstrate certain minimum qualifications, which the Corporate Governance Committee reviews annually:

• Proven integrity	• Mature and independent judgment	• Vision and imagination
• Ability to objectively appraise problems	• Ability to evaluate strategic options/ risks	• Sound business experience/acumen
• Relevant technological, political, economic, or social/culture experience	• Social consciousness	• Achievement of prominence in career
• Familiarity with national and international issues affecting the Company's business	• Contribution to the Board's desired diversity and balance	• Availability to serve for five years before reaching the directors' retirement age of 72 (in the case of new directors)

- While the Corporate Governance Committee does not have a specific policy with regard to the consideration of diversity in identifying director nominees, it strives to cast a wide net and recommend candidates who each bring a unique perspective to the Board in order to contribute to a collective diversity - diversity of knowledge, skills, experiences, thought, gender, ethnicity, tenure, and maturity.



- Directors' qualifications are also evaluated in the context of the Board's strategic initiatives, financial and operational performance objectives, and material risks. With that in mind, the Corporate Governance Committee and Board have determined through the Board succession planning process that the Board's composition should consist of candidates that collectively possess a specific set of core competencies as listed in the Proxy Summary on P-10, in order to effectively carry out its oversight function.

  During the third quarter of 2018, the Corporate Governance Committee and Board evaluated and affirmed this set of competencies. Each director then performed a self-assessment of his/her level of knowledge in each skill area using the following 3-point scale: "1" Limited knowledge (e.g., no direct experience, primary exposure comes from Board or Committee reports); "2" Intermediate knowledge (e.g., general managerial/oversight experience or broad exposure as a Board or Committee member); "3" Advanced knowledge (e.g., direct experience; subject matter expert). A summary of the Board's level of knowledge with respect to each of the core competencies was included in the Proxy Summary on page P-10. At least one director possesses advanced knowledge in each core competency.

DIRECTOR INDEPENDENCE

The guidelines the Board uses in determining director independence are located in Appendix A of the Corporate Governance Guidelines ("Guidelines"), which are available on the Corporate Governance section of our Company's website at www.wecenergygroup.com/govern/governance.htm. These Guidelines provide that the Board should consist of at least a two-thirds majority of independent directors. The independence standards found in our Guidelines are not only in compliance with the listing standards of the New York Stock Exchange ("NYSE"), but are actually more stringent than the NYSE rules. In order to be deemed independent, the individual must have no material relationship with the Company that would interfere with the exercise of good judgment in carrying out his or her responsibilities as a director.

Prior to initial and annual election, all directors complete a detailed questionnaire that elicits information that is used to ensure compliance with the Board's and the NYSE's standards of independence. The Corporate Governance Committee also reviews potential conflicts of interest, including related-party transactions, interlocking directorships, and substantial business, civic, and/or social relationships with other members of the Board that could impair the prospective Board member's ability to act independently from the other Board members and management. The Board also considers whether a director's immediate family members meet the independence criteria outlined in the Guidelines, as well as whether a director has certain relationships with WEC Energy Group's affiliates, when determining the director's independence.

The Board has affirmatively determined that Directors Bergstrom, Bowles, Brodsky, Budney, Chadwick, Culver, Cunningham, Farrow, Fischer, Knueppel, Payne, and Stanek are independent. Directors Klappa, Fletcher, and Leverett are not independent due to their employment with the Company.

Director Stanek. Since 2005, WEC Energy Group has engaged Baird Financial Group primarily to provide consulting services for investments held in the Company's various benefit plan trusts. The Board reviewed the terms of this engagement, including the approximately $680,000 in fees paid to Baird in 2018 (which are less than one-tenth of 1% of Baird's total revenue), and Ms. Stanek's position at Baird, and concluded that such engagement is not material and did not impact Ms. Stanek's independence. Ms. Stanek is not involved with and does not consult on the contract with or recommendations made by Baird and receives no direct financial benefit from these services. WEC Energy Group management evaluates Baird's services against market standards for overall quality and value on a regular basis. Neither the Board nor Ms. Stanek plays a role in the retention of Baird for these services or any related negotiation of commercial terms. In addition, WEC Energy Group's pension trusts and other benefit accounts do not hold any investments in Baird funds.

2019 DIRECTOR NOMINEES FOR ELECTION

The following 13 individuals have been nominated for election to the Board of Directors at the WEC Energy Group Annual Meeting. Biographical information for each director nominee is set forth below. Ages are as of January 17, 2019, the date each person was designated as a nominee of the Board for election at the Meeting.



Barbara L. Bowles

Age: 71

Director Since: 1998

Board Committees: Audit and Oversight; Corporate Governance (Chair); Executive

WEC Board: Independent Presiding Director

- Profit Investment Management LLC - Retired Vice Chair. Served as Vice Chair from January 2006 until retirement in December 2007. Profit Investment Management is an investment advisory firm.
- The Kenwood Group, Inc. - Retired Chairman. Served as Chairman from 2000 until 2006 when The Kenwood Group, Inc. merged into Profit Investment Management. CEO from 1989 to 2005.
- Director of Hospira, Inc. from 2008 to 2015.
- Director of WEC Energy Group since 1998; Director of Wisconsin Electric Power Company (subsidiary of WEC) from 1998 to June 2015.

Core competencies, qualifications and experience

As founder, CEO, and retired Chairman of The Kenwood Group, Inc., a Chicago-based investment advisory firm that managed pension funds for corporations, public institutions, and endowments, Ms. Bowles, who is a Chartered Financial Analyst, brings over 20 years of investment advisory experience to our Board of Directors. Having also served as a portfolio manager and utility analyst for more than 10 years, and as a chief investor relations officer for two Fortune 50 companies, she contributes valuable perspective as to what issues matter to large investors. In the role of Chief Compliance Officer of Profit Investment Management, Ms. Bowles gained a deep understanding of corporate governance issues and concerns, experience she applies to her positions as Chair of WEC Energy Group's Corporate Governance Committee and independent presiding director. She also contributes valuable risk management and financial reporting insights as a member of the Audit and Oversight Committee, expertise she developed from current and past service as a director on the boards of several other public companies where she has served on the audit and finance committees. With utility subsidiaries located in Chicago, the Board of Directors also benefits from the economic and political perspectives Ms. Bowles provides as a result of her involvement in several important non-profit organizations in Chicago.



Albert J. Budney, Jr.

Age: 71

Director Since: 2015

Board Committee: Corporate Governance

- Niagara Mohawk Holdings, Inc. - Retired President and Director. Served as President and Director from 1999 to 2002. Niagara Mohawk Holdings, Inc. is a holding company whose subsidiaries distribute electricity in New York.
- Director of WEC Energy Group since June 2015; Director of Integrys Energy Group from February 2007 to June 2015.

Core competencies, qualifications and experience

With over 40 years of utility experience in senior leadership positions, Mr. Budney brings to our Board of Directors extensive knowledge in managing the operations of a utility company and the complexities that arise from operating in a highly-regulated industry. He has acquired considerable board experience in utility industry mergers and acquisitions having served as a director of Niagara Mohawk Holdings when it was acquired by National Grid and of Integrys Energy Group when it was acquired by the Company. Mr. Budney brings to the Board knowledge of environmental issues that he gained as President of Niagara Mohawk Holdings while supervising the Vice President of Environmental Affairs. This provided Mr. Budney with experience he applied as a founding member of the Environmental Committee of the Board at Integrys Energy Group prior to its acquisition by WEC Energy Group. Having also served as the Chair of the Corporate Governance Committee and lead director of Integrys Energy Group, Mr. Budney's broad knowledge in governance, corporate management, and strategic planning matters are very valuable to the Board in carrying out its oversight in these areas.



Patricia W. Chadwick

Age: 70
Director Since: 2006
Board Committees: Audit and Oversight; Finance

- Ravengate Partners, LLC - President since 1999. Ravengate Partners, LLC provides businesses and not-for-profit institutions with advice about the financial markets, business management, and global economics.
- Director of AMICA Mutual Insurance Company since 1992; Director of VOYA Mutual Funds (previously ING Mutual Funds) since 2006; Director of The Royce Funds since 2009.
- Director of WEC Energy Group since 2006; Director of Wisconsin Electric Power Company (subsidiary of WEC) from 2006 to June 2015.

Core competencies, qualifications and experience

Ms. Chadwick, who is a Chartered Financial Analyst, brings to our Board of Directors extensive investment management expertise gained from more than 30 years of experience as an investment professional, portfolio manager or principal. As founder and President of Ravengate Partners, a firm that has been educating and advising businesses and not-for-profit institutions about the financial markets and global macro economy since 1999, Ms. Chadwick's insights into the investment industry's perspectives is valuable to the Board's financial planning and strategy discussions. Her knowledge of capital markets is particularly helpful to WEC Energy Group and its subsidiaries, which operate in a capital intensive industry and consistently access the capital markets. Ms. Chadwick serves as a director and committee member on the boards of two registered investment companies, VOYA Mutual Funds and The Royce Funds, through which she has developed extensive governance experience with respect to audit oversight and financial reporting. As a board director and Finance Committee member of AMICA Mutual Insurance Company, she has gained a deep understanding of insurance risk management and oversight matters, which is valuable experience that she applies to her role on the WEC Energy Group Finance Committee.



Curt S. Culver

Age: 66
Director Since: 2004
Board Committees: Corporate Governance; Finance (Chair)

- MGIC Investment Corporation - Non-Executive Chairman of the Board since March 2015. Served as Chairman from 2005 to February 2015, CEO from 2000 to February 2015, and President from 1999 to 2006. MGIC Investment Corporation is the parent of Mortgage Guaranty Insurance Corporation.
- Mortgage Guaranty Insurance Corporation - Non-Executive Chairman of the Board since March 2015. Served as Chairman from 2005 to February 2015, CEO from 1999 to February 2015, and President from 1996 to 2006. Mortgage Guaranty Insurance Corporation is a private mortgage insurance company.
- Director of MGIC Investment Corporation since 1999.
- Director of WEC Energy Group since 2004; Director of Wisconsin Electric Power Company (subsidiary of WEC) from 2004 to June 2015.

Core competencies, qualifications and experience

Having served for 15 years as the CEO of Mortgage Guaranty Insurance Corporation and its parent company, MGIC Investment Corporation, Mr. Culver brings to our Board of Directors a strong working knowledge of the strategic, economic, and public policy issues facing a large, regulated, publicly-held company headquartered in Milwaukee, Wisconsin. His expertise in risk management and oversight is particularly valuable in his service as chair of the Finance Committee, while his insurance industry experience puts him in a position to lead the Committee's evaluation of the Company's overall risk management program. Mr. Culver's broad corporate governance experience, developed from his extensive past and present service on the MGIC boards, as well as several highly-visible Milwaukee-area non-profit entities and two private for-profit organizations, is of great value to the Board as it carries out its oversight responsibilities.



Danny L. Cunningham

Age: 63
Director Since: 2018
Board Committees: Audit and Oversight

- Deloitte & Touche LLP - Retired Partner and Chief Risk Officer. Served as Partner from 2002 to 2015 and as Chief Risk Officer from 2012 to 2015. Deloitte & Touche LLP is an industry-leading audit, consulting, tax, and advisory firm.
- Director of Actuant Corporation since 2016.
- Director of WEC Energy Group since January 2018.

Core competencies, qualifications and experience

Mr. Cunningham brings to our Board of Directors more than 30 years of experience serving public audit clients in a broad array of industries, including manufacturing, printing, process, software, and financial services, as well as a deep understanding of the business, economic, compliance, and governmental environment in which the Company and many of the Company's major customers operate. Mr. Cunningham's strong expertise in financial reporting, internal controls, and audit functions are of great value to the Board as it fulfills its responsibility for oversight of the Company's accurate preparation of financial statements and disclosures, and compliance with legal and regulatory requirements. Having served as chief risk officer at Deloitte & Touche LLP, he gained keen insights into the complexities of risk management, through which he applies his expertise in assessing the effectiveness of the Company's practices and policies to mitigate enterprise-wide risks. Mr. Cunningham's multi-national experience brings the added diversity of a global perspective to the Board as it evaluates its strategic objectives, while his past service on the boards of several major Milwaukee-area not-for-profit organizations equips him to contribute thoughtful insights on issues impacting the city's culture, workforce, and economic vitality.



William M. Farrow III

Age: 63
Director Since: 2018
Board Committees: Finance

- Winston and Wolfe, LLC - Chairman and Chief Executive Officer since 2010. Winston and Wolfe LLC is a privately held technology development and advisory company.
- Urban Partnership Bank - Retired President and CEO from August 2010 to January 2018. UPB provides financial services in moderate income communities located in Chicago, Detroit and Cleveland.
- Director of CBOE Global Markets Inc. since 2016; Director of Echo Global Logistics Inc. since 2017.
- Director of WEC Energy Group since January 2018.

Core competencies, qualifications and experience

Mr. Farrow brings to our Board of Directors 40 years of senior leadership experience in managing business operations, technology development, enterprise risk and strategy. His extensive professional experience in the banking and financial markets, accompanied by knowledge acquired from his service on the boards of CBOE Global Markets and the Federal Reserve Bank of Chicago, enables him to add significant value to the Board's oversight of the Company's financial management strategy. His first-hand experience and perspectives in addressing advances in information technology, as well as the experience he's gained as a current board member on the Audit Committee for both CBOE Global Markets and Echo Global Logistics, is particularly valuable to the Board as WEC Energy Group companies address complex risks, including those associated with protecting operating systems and assets against physical and cyber threats. Having spent his career in the City of Chicago, Mr. Farrow is also able to provide the Board with economic and public policy insight as it relates to conducting business in Chicago, which is further enhanced by the strong relationships he has developed with key leaders while serving on the boards of several highly-visible Chicago-area private, not-for-profit and community organizations. This is especially important given the sizable, long-term construction project that is underway by the Company's Illinois utility subsidiary to modernize the natural gas infrastructure in the City of Chicago, which requires ongoing collaboration with city and state government officials and regulatory agencies.



Thomas J. Fischer

Age: 71

Director Since: 2005

Board Committees: Audit and Oversight (Chair); Compensation; Executive

- Fischer Financial Consulting LLC - Principal since 2002. Fischer Financial Consulting LLC provides consulting on corporate financial, accounting, and governance matters.
- Director of Actuant Corporation from 2003 to January 2017; Director of Badger Meter, Inc. since 2003; Director of Regal Beloit Corporation since 2004.
- Director of WEC Energy Group since 2005; Director of Wisconsin Electric Power Company (subsidiary of WEC) from 2005 to June 2015.

Core competencies, qualifications and experience

Mr. Fischer provides our Board of Directors with significant expertise in accounting and auditing matters, including financial reporting and regulatory compliance, risk assessment and management, and corporate governance issues. His experience in these areas comes from 33 years of work at Arthur Andersen, a large, international independent accounting firm, where for 22 years, he served as a partner responsible for services provided to large, complex public and private companies and several public utility audits. Since 2002, Mr. Fischer has provided consulting services to companies in the areas of corporate financial, accounting, and governance matters. Mr. Fischer, who is a Certified Public Accountant, brings extensive knowledge and experience to his responsibilities as WEC Energy Group's Audit and Oversight Committee Chair as a result of his past and present service on several other audit committees at public companies based in Wisconsin. His significant expertise is invaluable to WEC Energy Group's Board as it navigates a complex and evolving regulatory compliance landscape.



J. Kevin Fletcher

Age: 60

Director Since: 2019

- WEC Energy Group, Inc. - CEO since February 2019; President since October 2018.
- Wisconsin Electric Power Company (subsidiary of WEC) - Chairman of the Board and Chief Executive Officer since February 2019; President from May 2016 to November 2018; Executive Vice President-Customer Service and Operations from June 2015 to May 2016; Senior Vice President-Customer Operations from October 2011 to June 2015.
- Director of WEC Energy Group, Inc. since February 2019; Director of Wisconsin Electric Power Company since June 2015.
- Mr. Fletcher also serves as an executive officer and/or director of several other major subsidiaries of WEC Energy Group.

Core competencies, qualifications and experience

Mr. Fletcher has more than 40 years of experience working in the public utility industry, including nearly 25 years at a senior leadership level. Prior to joining the Company in 2011, Mr. Fletcher served as Senior Vice President-Community and Economic Development at Georgia Power, the largest subsidiary of The Southern Company, a public utility holding company serving the southeastern United States. During his 34-year career with Southern Co., 16 of those years as an officer, Mr. Fletcher held leadership positions in operations, customer service, marketing and sales. When he first joined WEC Energy Group, he served as Senior Vice President-Customer Operations of its utility subsidiaries, with overall responsibility for the planning, engineering, construction, operation and maintenance of the Company’s electric and natural gas distribution systems in Wisconsin and Michigan’s Upper Peninsula. In May 2016, he was appointed to serve as President of the Company’s Wisconsin utility subsidiaries, and assumed responsibilities as President of the Company’s Minnesota and Michigan utility subsidiaries in September 2018. In October 2018, Mr. Fletcher was appointed President of WEC Energy Group, followed by his appointment to CEO in February 2019, whereby he has financial and operational responsibility for all of the Company's utility subsidiaries. He also has held responsibility for the supplier diversity initiative across all of the Company’s utilities. With his extensive experience in business operations, customer service, and senior leadership of publicly regulated utilities, Mr. Fletcher contributes substantive insight into the Company’s industry and customers, to the management team, and to the Board.



Gale E. Klappa

Age: 68
Director Since: 2003
Board Committee: Executive (Chair)

- WEC Energy Group, Inc. - Executive Chairman since February 2019; Chairman of the Board and CEO from 2004 to May 2016 and October 2017 to February 2019; Non-Executive Chairman of the Board from May 2016 to October 2017; President from 2003 to August 2013.
- Wisconsin Electric Power Company (subsidiary of WEC) - Chairman of the Board from 2004 to May 2016 and January 2018 to February 2019; CEO from 2003 to May 2016 and January 2018 to February 2019; President from 2003 to June 2015.
- Director of Associated Banc-Corp since 2016 and Director of Badger Meter, Inc. since 2010, both headquartered in Wisconsin; Director of Joy Global Inc. from 2006 to 2017.
- Director of WEC Energy Group, Inc. since 2003; Director of Wisconsin Electric Power Company from 2003 to May 2016 and January 2018 to present.
- Mr. Klappa also serves a director of several other major subsidiaries of WEC Energy Group.

Core competencies, qualifications and experience

Mr. Klappa has more than 40 years of experience working in the public utility industry, including more than 25 at a senior executive level. He retired as the Company's CEO in May 2016, at which time he assumed the role of Non-Executive Chairman of the Board. Prior to joining the Company in 2003, Mr. Klappa served in various executive leadership roles at The Southern Company, a public utility holding company serving the southeastern United States. Under his leadership, WEC Energy Group successfully completed its 2015 acquisition of Integrys Energy Group, which nearly doubled the employee and customer population, and increased the Company's geographic footprint to four states. With his extensive experience in the business operations and C-suite leadership of publicly regulated utilities, his service as a board member for several other public companies, and his contributions to significant economic development initiatives in southeastern Wisconsin, Mr. Klappa has led the Board with a deep understanding of the financial investment decisions and public policy issues facing large public companies. In October 2017, after the Company's then-CEO, Allen Leverett, suffered a stroke, the Board appointed Mr. Klappa to serve in the role of CEO, while also having him retain his role of Board Chairman. With the appointment of Mr. Fletcher as CEO effective February 2019, Mr. Klappa now serves as Executive Chairman. Mr. Klappa's deep knowledge of the Company's industry, customers, stockholders, and management team is of great value to the Board.



Henry W. Knueppel

Age: 70
Director Since: 2013
Board Committees: Audit and Oversight; Corporate Governance

- Regal Beloit Corporation - Retired Chairman of the Board and CEO. Served as CEO from 2005 to 2011 and as Chairman from 2006 to 2011. Regal Beloit Corporation is a leading manufacturer of electric motors, mechanical and electrical motion controls, and power generation products.
- Harsco Corporation - Independent, Non-Executive Chairman of the Board from September 2012 until September 2014. Served as Interim Chairman and CEO from February 2012 to September 2012 and Director from 2008 to April 2016. Harsco Corporation is a diversified, worldwide industrial services company.
- Director of Regal Beloit Corporation since 1987; Director of Snap-on Incorporated since 2011.
- Director of WEC Energy Group since 2013; Director of Wisconsin Electric Power Company (subsidiary of WEC) from 2013 to June 2015.

Core competencies, qualifications and experience

With more than 30 years of senior management experience at Regal Beloit Corporation, including five years as the combined Chairman of the Board and CEO, Mr. Knueppel brings extensive executive management experience to our Board of Directors, including strategic planning, financial strategy and talent management perspective. Regal Beloit Corporation is a Wisconsin-based manufacturer of electrical motors, mechanical and electrical motion controls, and power generation products, which gives Mr. Knueppel knowledge of key equipment used in the Company's operations. He currently serves on the boards of several large, publicly-traded industrial companies and provides the Board with perspective on operational matters the Company faces in serving its large commercial and industrial customers. Mr. Knueppel also brings to the Board a wide range of knowledge and experience in corporate governance, having served for more than 30 years as a director for several publicly-traded companies, including his role as the independent, non-executive chairman of the board of Harsco Corporation.



Allen L. Leverett

Age: 52
Director Since: 2016

- WEC Energy Group, Inc. - President from August 2013 to October 2018; CEO from May 2016 to October 2017; Executive Vice President from 2004 through July 2013; CFO from 2003 until 2011. Mr. Leverett also served as the principal executive officer of WEC Energy Group's generation operations from 2011 to May 2016.
- Wisconsin Electric Power Company (subsidiary of WEC) - Chairman of the Board and CEO from May 2016 through December 2017; President from June 2015 to May 2016; Executive Vice President from 2004 through June 2015; CFO from 2003 until 2011.
- Director of WEC Energy Group since January 2016; Director of Wisconsin Electric Power Company from June 2015 to January 2018.

Core competencies, qualifications and experience

Having worked in the public utility industry for nearly 25 years, Mr. Leverett has a deep understanding of the complexities of the Company's industry, operations, and regulatory environment, while having built extensive senior leadership experience. Mr. Leverett served in executive positions at Georgia Power and Southern Company Services, where he held overall responsibility for financial planning and analysis, capital markets and leasing, treasury, and investor relations. He joined WEC Energy Group in 2003 as CFO and proceeded to hold numerous executive positions, including President and CEO of the Company's power generation group, with overall responsibility for the electric generation portfolio, fuel procurement, environmental compliance, and renewable energy development strategy. Following the Company's acquisition of Integrys Energy Group in June 2015, Mr. Leverett served as President of the Company's utilities located in Wisconsin, Michigan, and Minnesota through early 2016. Effective May 1, 2016, Mr. Leverett was appointed as CEO of WEC Energy Group and served in that role until October 2017, when he suffered a stroke and began a medical leave of absence. In October 2018, Mr. Leverett resigned as President of the Company, while retaining his role as a member of the Board. Mr. Leverett's experience and insights in running a regulated public company serve as critical inputs to the Board's oversight of the Company's long-term strategic plan.



Ulice Payne, Jr.

Age: 63
Director Since: 2003
Board Committees: Compensation; Executive; Finance

- Addison-Clifton, LLC - Managing Member since 2004. Addison-Clifton, LLC provides global trade compliance advisory services.
- Director of Foot Locker, Inc. since December 2016; Director of Manpower Group since 2007; Trustee of The Northwestern Mutual Life Insurance Company since 2005.
- Director of WEC Energy Group since 2003; Director of Wisconsin Electric Power Company (subsidiary of WEC) from 2003 to June 2015.

Core competencies, qualifications and experience

Mr. Payne brings to our Board of Directors strong senior leadership and public service experience within the greater Milwaukee community and State of Wisconsin, having previously served in roles that included the Securities Commissioner for the State of Wisconsin, managing partner of the Milwaukee office of the law firm Foley & Lardner LLP, and president and CEO of the Milwaukee Brewers Baseball Club, Inc. In addition, Mr. Payne is involved in numerous Milwaukee-area non-profit entities, making him well-positioned to provide the Board with perspective on the economic and social issues affecting the greater Milwaukee area, as well as a broad spectrum of the Company's customers. As founder and President of Addison-Clifton, LLC, which provides global trade compliance consulting, Mr. Payne understands the importance of providing clients with exceptional customer service, a focus that is critical to execution of WEC Energy Group's strategic initiatives. Mr. Payne also contributes valuable financial and risk assessment insights gained throughout his career, including from his past and present service on the boards of several public companies, for which he has served as a member of the Audit, Finance, and/or Corporate Governance committee at each of these companies.



Mary Ellen Stanek

Age: 62
Director Since: 2012
Board Committee: Finance

- Baird Financial Group - Managing Director and Director of Asset Management since 2000. Baird Financial Group provides wealth management, capital markets, private equity, and asset management services to clients worldwide.
- Baird Advisors - Chief Investment Officer since 2000. Baird Advisors is an institutional fixed income investment advisor.
- Baird Funds, Inc. - President since 2000. Baird Funds is a publicly registered investment company.
- Trustee of The Northwestern Mutual Life Insurance Company since 2009.
- Director of Journal Media Group, Inc. and its predecessor companies from 2002 to April 2016.
- Director of WEC Energy Group since 2012; Director of Wisconsin Electric Power Company (subsidiary of WEC) from 2012 to June 2015.

Core competencies, qualifications and experience

Ms. Stanek, who is a Chartered Financial Analyst, brings to our Board of Directors extensive financial and investment strategy expertise, resulting from over 40 years of investment management experience. As Managing Director and Director of Asset Management of Baird Financial Group, a position she has held since 2000, Ms. Stanek's expertise in fixed income investments provides the Board and management with invaluable financial strategy insight relative to WEC Energy Group and its subsidiaries, which customarily issue debt securities as a means of raising capital. As a member of the WEC Energy Group Finance Committee, she also offers valuable perspective on insurance risk matters, having served for 15 years as a director of West Bend Mutual Insurance Company. In addition to her recognition as a prominent business leader in Milwaukee's financial community, Ms. Stanek has dedicated significant time to serving on the boards of a large number of Milwaukee-area non-profit organizations, through which she has developed strong relationships with key community leaders and stakeholders. From these experiences, she brings the Board insightful perspectives on issues impacting the culture and viability of today’s workforce.

GOVERNANCE

Accountability to stockholders is critical to the Company's long-term success. We have mechanisms in place to ensure that management and the Board hear, understand, and consider the issues that matter most to our stockholders. This ongoing engagement provides valuable insight into how our stockholders view the Company's practices and policies, shapes the processes used to evaluate goals and expectations, and identifies emerging issues that may affect our corporate governance and compensation practices.

STOCKHOLDER ENGAGEMENT

Under the Board's oversight, Company leadership regularly engages with investors to discuss business results, strategic direction, and corporate governance and compensation practices through a year-round stockholder engagement program. The Company's outreach and engagement program took many forms during 2018:

- Direct engagement by senior management with the Company's stockholders to discuss issues of interest, including corporate governance, executive compensation, and corporate responsibility practices. These conversations are reported to the Board and are taken into consideration when reviewing and modifying governance and compensation practices and policies.
- Investor presentations conducted at analyst meetings and investor conferences across the U.S., Canada, and Europe.
- CEO, CFO, and other senior management meetings and conference calls with stockholders to discuss corporate strategy, financial and business performance, and to update stockholders on key developments.
- Invitations to investors to listen to Webcasts of the Annual Meeting and quarterly earnings conference calls, and to view the annual report, news releases, Securities and Exchange Commission ("SEC") filings, and other significant corporate publications on our Website.
- The opportunity to attend and voice opinions at our Annual Meeting.
- The ability for stockholders to submit stockholder proposals and director nominees, and to formally nominate director candidates using proxy access as permitted under our bylaws.
- Annual election of directors, who are elected by majority vote in uncontested elections.
- Annual advisory vote on our executive compensation program ("say-on-pay").
- Strong Board committee structure, which allows the Board to focus on issues that matter most to our stockholders, including consideration of previous stockholder votes on say-on-pay, director elections, and other matters when developing policies and practices.
- Process for stockholders to directly correspond with individual directors via the Corporate Secretary page P-31.

Below is a summary of our yearly corporate governance practices related to stockholder engagement on environmental, social and governance ("ESG") topics.

SUMMER	FALL	WINTER	SPRING
• Review results from Annual Meeting of Stockholders • Engage with stockholders to discuss voting results • Conduct annual assessment of corporate governance practices to identify potential areas of focus • Discuss voting results, investor feedback, and annual assessment with Board	• Meet with institutional investors to discuss our governance and compensation practices and to address questions or concerns • Consider enhancements to our practices and disclosures based on investor feedback • Share investor feedback and recommendations for changes in practices and disclosures with Board committees and full Board	• Approve any changes to corporate governance and compensation practices • Develop disclosures for the proxy statement	• Publish annual disclosure documents (Form 10-K, Annual Report, Proxy Statement) • Hold Annual Meeting of Stockholders

CORPORATE GOVERNANCE FRAMEWORK

Corporate Governance Guidelines

In 1996, WEC Energy Group became one of the earliest adopters of a formal set of Corporate Governance Guidelines, which have been modified over the years in response to evolving governance best practices and stockholder expectations. To maintain effective guidelines, the Corporate Governance Committee annually reviews the Company's governance practices, taking into consideration discussions with stockholders as part of our investor outreach and engagement program, industry surveys, and benchmarking studies, as well as governance guidelines published by institutional investors and proxy advisors.

Key governance practices adopted by the Board include:

GOVERNANCE PRINCIPLES	WEC ENERGY GROUP PRACTICES
Board composition	✓ • Annual election of directors since 2005 • 10 of 13 independent directors (based on director nominees) • Diverse representation of skills and competencies • Regular Board refreshment and mix of tenure • Comprehensive, ongoing Board succession planning process • Expectation that directors will dedicate sufficient time to perform duties
Board leadership	✓ • Separate CEO/Chair roles • Presiding independent director with defined duties • Chairman active in stockholder engagement and communications
Board governance practices	✓ • Expectation that directors participate in annual meeting with stockholders • Annual performance evaluations of CEO, Board, and Board committees • 100% independent Board Committees (except for the Executive Committee) • Board participation in critical activities, including agenda setting and strategic planning • Complete access to management and outside advisors for Board members • Stock ownership requirements • Regular executive sessions of independent directors at Board and committee meetings
Stockholder voting rights	✓ • Stockholders' ability to nominate directors; proxy access bylaw adopted in 2016 • One-share, one-vote standard; dual class voting is not practiced • Special meeting provisions
Executive compensation	✓ • Competitively tailored to business and industry, aligned with long-term performance and business strategy • Utilizes short- and long-term metrics, cash, and equity components; substantial portion is at risk • Public disclosure of peer groups, benchmarks, and performance measurements • Clawback policies for cash and equity; prohibition of hedging and pledging of Company securities • Stock ownership requirements

Business Conduct and Ethics

WEC Energy Group's Code of Business Conduct, which was benchmarked and updated in 2017 to comport with best practices, addresses, among other things: conflicts of interest; confidentiality; fair dealing; protection and proper use of Company assets; and compliance with laws, rules, and regulations (including insider trading laws). All WEC Energy Group directors, executive officers, and employees, including the principal executive, financial, and accounting officers, have a responsibility to comply with WEC Energy Group's Code of Business Conduct, to seek advice in doubtful situations, and to report suspected violations. The Company has not provided any waiver to the Code for any director, executive officer, or other employee.

The Company has several ways individuals can raise questions concerning WEC Energy Group's Code of Business Conduct and other Company policies. As one reporting mechanism, the Company has contracted with an independent service so that individuals can confidentially and anonymously report suspected violations of the Code of Business Conduct or other concerns, including those regarding accounting, internal accounting controls, or auditing matters.

Related Party Transactions/Conflicts of Interest

The Code of Business Conduct addresses, among other things, what actions are required when potential conflicts of interest may arise, including those from related-party transactions. Specifically, executive officers and members of the Board must obtain approval of the Audit and Oversight Committee Chair before: (1) obtaining any financial interest in or participating in any business relationship with any company, individual, or concern doing business with WEC Energy Group or any of its subsidiaries

that might influence the individual's decisions or job performance; (2) participating in any joint venture, partnership, or other business relationship with WEC Energy Group or any of its subsidiaries; and (3) serving as an officer or member of the board of any substantial, outside for-profit organization. Furthermore, before serving as an officer or member of the board of any substantial, outside for-profit organization, the CEO must obtain the approval of the full Board; members of the WEC Energy Group Board must obtain the prior approval of the Corporate Governance Committee. In addition, executive officers must obtain the prior approval of the CEO before accepting a position with a substantial non-profit organization; members of the Board must notify the Compliance Officer when joining the board of a substantial non-profit organization, but do not need to obtain prior approval.

WEC Energy Group's Code of Business Conduct also requires employees and directors to notify the Compliance Officer of situations where family members are a supplier or significant customer of WEC Energy Group or employed by one. To the extent the Compliance Officer deems it appropriate, he will consult with the Audit and Oversight Committee Chair in situations involving executive officers and members of the Board.

BOARD LEADERSHIP

Leadership Structure

Consistent with WEC Energy Group's bylaws and our Corporate Governance Guidelines, the Board retains the right to exercise its discretion in combining or separating the offices of Chief Executive Officer and Chairman of the Board. From May 1, 2016 to October 12, 2017, the office of the CEO was separated from the office of Chairman of the Board. Gale Klappa served as Non-Executive Chairman and Allen Leverett served as CEO. On October 12, 2017, the Board appointed Gale Klappa to serve as CEO during Mr. Leverett's medical leave. Mr. Klappa served as Chairman and CEO until February 1, 2019, when the Board appointed J. Kevin Fletcher as CEO and named Mr. Klappa as Executive Chairman of the Board, thus again separating the CEO and Chair positions.

Independent Presiding Director

Our Corporate Governance Guidelines detail the specific duties to be performed by the Board's Independent Presiding Director, a position that is currently held by Director Bowles, Chair of the Corporate Governance Committee. Duties of this role include:

- presides at all meetings of the Board at which the Chairman is not present, including executive sessions of the non-management directors;
- serves as liaison between the CEO and the independent directors under most circumstances, although each individual director has full access to the CEO;
- has authority to call meetings of the independent directors;
- reviews and provides input to meeting agendas for the Board and its Committees;
- reviews meeting schedules to assure there is sufficient time for discussion of all agenda items;
- reviews all proposed changes to committee charters; and
- leads the annual Board evaluation.

RISK OVERSIGHT

The Board has overall responsibility for risk oversight and oversees the Company's risk environment and associated management practices as part of its evaluation of the Company's ongoing operations and strategic direction. During meetings of the Board and its committees, directors receive regular briefings from management on specific areas of risk, as well as emerging risks to the enterprise.

While it has retained oversight of certain broad risks that could impact the Company's long-term strategy, including, for example, climate change risk, the Board has delegated certain risk monitoring responsibilities to its committees. With the exception of the Executive Committee, each of the Board's committees regularly reports to the full Board on risks that fall within designated areas of responsibility, as described in each committee's respective charter. Examples of risk monitoring activity that have been designated to committees is shown in the chart below. More information on the committees' duties and responsibilities begins on page P-27.



Executive sessions for the non-management directors are generally held at every regularly scheduled committee meeting, during which committees have direct access to, and meet as needed with, Company representatives without other management present to discuss matters related to, among other things, risk management. Outside of scheduled meetings, the Board, its committees, and individual Board members have full access to senior executives and other key employees, including the CEO, CFO, General Counsel, Chief Audit Officer, Compliance Officer, Chief Information Officer, and Controller.

The Company has an Enterprise Risk Steering Committee, comprised of senior-level management employees whose purpose is to foster an enterprise-wide approach to identifying and managing risk. The Audit Services department conducts a semiannual enterprise risk assessment, and as part of this process, business leaders identify existing, new, or emerging issues or changes within their business areas that could have enterprise implications. Senior management is tasked with ensuring that these risks and opportunities are appropriately addressed. The results of these risk management efforts are reported to the executive leadership team and are the subject of regular reports to the Board.

The Board believes that its leadership structure and enterprise risk management program support the risk oversight function of the Board.

ENVIRONMENTAL AND SOCIAL GOVERNANCE

The Board is vigilant in its oversight of management's strategic decision-making as it navigates important developments in our industry, including new technologies, customer preferences, commodity prices, energy resiliency efforts, and ESG initiatives. Examples of how the Company's ESG practices are aligned with the needs of our stakeholders and support the well-being of the areas we serve are provided here.

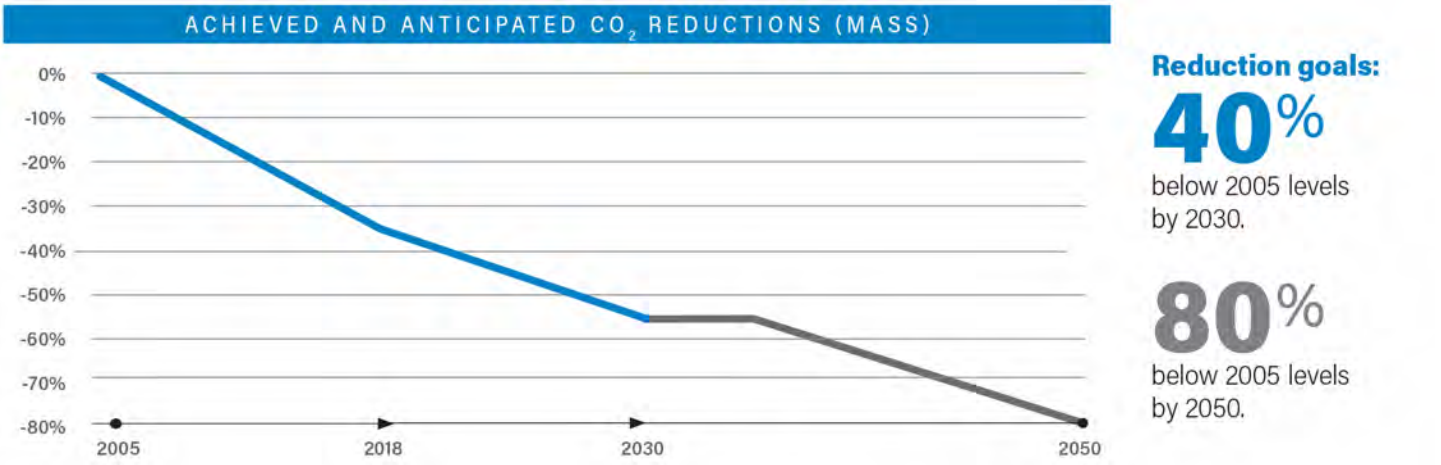
Environmental Stewardship

Protecting the environment is a responsibility we take seriously. Since 2000, the Company has invested in repowered generating facilities, renewable energy projects, state-of-the-art air quality control systems, power grid upgrades, and additional environmental protection technologies that position our electric generating companies well for the future.

We are working with our industry partners, environmental groups, and the State of Wisconsin to reduce carbon dioxide emissions, and we have set a two-part goal:

- 40 percent reduction below 2005 levels by 2030
- 80 percent reduction below 2005 levels by 2050

We are collaborating with Electric Power Research Institute and other industry members on the analysis of potential pathways beyond 2030 for electric companies, taking into account International Energy Agency's 2-degree scenario and other publicly available data.



Social Performance

Our employees are the bedrock of our business, driving key corporate initiatives focused on safety, diversity and inclusion, and talent development.

- Since 2008, the total number of OSHA-recordable and lost-time incidents have been reduced by 59 and 51 percent, respectively.
- Forbes included WEC Energy Group in its 2019 ranking of 'Best Employers for Diversity' and in its 2017 ranking of 'America's Best Employers.'
- We conducted a Company-wide, confidential employee engagement survey in 2018 to gauge employees' perceptions of their work, their leadership and the Company as a whole; leadership is using the results to actively address areas where the need for improvement was identified.

We are also deeply committed to our customers, suppliers, and communities.

- Again in 2018, WEC was recognized by Corporate Responsibility Magazine as one of the 100 best corporate citizens in America.
- In 2018, We Energies was named the most reliable utility in the Midwest for the eighth consecutive year by PA Consulting Group.
- Our companies spent more than $263.1 million in 2018 with certified minority-, women-, veteran- or service disabled-owned businesses, a nearly 50 percent increase over 2016.

Commitment to Reporting Transparency

In addition to engaging directly with stakeholders on environmental and social issues, we are committed to enhancing our transparency on these matters through a variety of reporting mechanisms, including:

- In 2019, the Company will issue its 18th annual Corporate Responsibility Report, covering our ESG performance in 2018.
- In 2019, the Company will issue its first report focused on climate change.
- For more than a decade, the Company has disclosed information regarding operations and ESG goals, risks and opportunities to CDP; the 2018 survey responses on climate and water can be found on the Company's website.
- The Company contributed to Edison Electric Institute's development of a template designed to make ESG metrics and information more accessible to investors and comparable across the electric sector.
- See the Corporate Responsibility section of our website for more details: www.wecenergygroup.com/csr

BOARD AND COMMITTEE PRACTICES

Board Meetings and Executive Sessions

During 2018, the Board met nine times and executed one written unanimous consent. All directors attended more than 75% of the total number of meetings of the Board and Board committees on which he or she served with the exception of Mr. Leverett who was excused for medical reasons. Mr. Leverett has consistently attended Board meetings since his return. Generally, all directors are expected to attend the Company's Annual Meetings of Stockholders. With the exception of Messrs. Bergstrom and Leverett, all directors attended the Annual Meeting of Stockholders held on May 3, 2018.

At every regularly scheduled Board and committee meeting, executive sessions are scheduled, and are generally held, for the non-management directors to meet without management present.

Director Orientation and Continuing Education

Management takes very seriously its responsibility to onboard new directors and continuously educate existing directors on the unique and complex issues inherent in operating a public company in the regulated utility industry.

Management has created a robust orientation program that introduces new directors to the Company's organizational structure, businesses, strategies, risks and opportunities, which assists new directors in developing company and industry knowledge to optimize their service on the Board. Directors Cunningham and Farrow engaged in a substantive orientation program throughout 2018, which included both in-house and field programming.

Opportunities to participate in regular continuing education are provided to the directors in the form of internally developed materials and presentations, programs presented by third parties, and financial support to attend qualifying academic or other independent programs, which help our directors enhance the skills and knowledge needed to carry out their responsibilities. During 2018, management facilitated numerous educational programs in which both Company and third-party experts presented to and discussed with the directors a variety of strategic and industry-related topics.

Succession Planning

Board Succession Planning

The Board is regularly engaged in rigorous discussions on Board succession planning, taking into consideration matters such as: current inventory of director skills; diversity, including gender, ethnicity, retirement age, and tenure; and future competencies needed to support appropriate oversight of the Company's strategic initiatives, financial and operational performance, and enterprise risks. During 2018, these discussions took into consideration the impact of Directors Bergstrom and Brodsky completing their service on the Board in May 2019, as well as the fact that multiple other directors will reach retirement age over the next two years. The election of Directors Cunningham and Farrow in 2018, and the election of Director Fletcher in February 2019, added skills and perspectives to the Board in areas it had determined were essential for carrying out its oversight responsibilities.

Management Succession Planning

The Compensation Committee, which has responsibility for reviewing organizational changes that have a significant impact on the Company, as well as reviewing succession plans for executive officers, held numerous discussions throughout 2018 to ensure continuity with respect to a number of organizational matters that occurred. The Committee also reviewed the Company's recruiting and development programs, which included updates on key talent, as well as workforce demographics across the organization.

Throughout 2018, the Board was also actively engaged in oversight of the executive succession planning process. The Board spent considerable time discussing the progress of Mr. Leverett's recovery with respect to his potential return to his executive duties. It also devoted significant time to evaluating alternatives in the event that Mr. Leverett did not return in an executive capacity.

In October 2018, Mr. Leverett resigned from his duties as President of WEC Energy Group, while retaining his position as a Board director. The Board approved of management's plan for a series of internal promotions, including appointing Mr. Fletcher as President, and associated reorganization activities in response to Mr. Leverett's resignation. Effective February 1, 2019, the Board appointed Mr. Fletcher as CEO of WEC Energy Group to succeed Mr. Klappa, who was appointed Executive Chairman.

The Board also approved the creation of the Office of the Chair comprised of four industry veterans: Gale Klappa, J. Kevin Fletcher, Scott Lauber, and Frederick Kuester. The Board believes this structure is appropriate to continue the smooth transition in leadership following Mr. Leverett's resignation as an active employee. This structure solidifies a strong and seasoned leadership team with the experience and skills needed to establish and carry out the Company's strategies, and provides the Company with strong and balanced executive leadership.

Annual Performance Evaluations

CEO Performance

The Compensation Committee, on behalf of the Board, annually evaluates the performance of the CEO and reports the results to the Board. The CEO is evaluated in a number of areas including leadership, vision, financial stewardship, strategy development and execution, management development, effective communication with constituencies, demonstrated integrity, and effective representation of the Company in community and industry affairs.

As part of this practice, the Compensation Committee obtains from each non-management director his or her input on the CEO's performance, which is summarized and then discussed in executive session with all non-management directors. The Chair of the Compensation Committee shares the evaluation results with the CEO. This procedure allows the Board to evaluate the CEO and to communicate the Board's expectations. The process is also used by the Compensation Committee to determine appropriate compensation for the CEO. This process was completed for Mr. Klappa in December 2018.

Board Performance

The Board annually evaluates its own performance, a process that is led by the Independent Presiding Director. The Board uses a framework of questions developed by the National Association of Corporate Directors to conduct the performance evaluation. Each director independently considers several "reflection" questions, in addition to a list of questions that fall within five broad categories: board composition and leadership; board committees; board meetings; overall effectiveness of the Board; and overall effectiveness of the Board with regard to management.

The Independent Presiding Director uses this framework to provide each Board member an opportunity to speak candidly during one-on-one discussion sessions. At the conclusion of the individual feedback sessions, the Independent Presiding Director leads the Corporate Governance Committee and the Board through a group discussion of key takeaways. This evaluation process was conducted in November and December of 2018, following which the Corporate Governance Committee and the Board discussed the findings at their meetings in January 2019. It is routine practice for the Board to incorporate recommendations from its evaluation process into new standard practices, and the Corporate Governance Committee routinely uses the results of this process to foster continuous improvement of the Board's governance activities.

Committee Performance

Each committee, except the Executive Committee, conducts an annual performance evaluation of its own activities and reports the results to the Board. During this evaluation, each committee compares its performance against the requirements of its charter and its annual planning calendar; contemplates a series of questions related to the qualifications and performance of committee members; considers the quality and quantity of information provided to the committee in advance of its meetings; and evaluates the effectiveness of the processes the committee uses to carry out its oversight responsibilities. The results of the annual evaluations are used by each committee to identify its strengths and areas where its governance practices can be improved. Each committee may recommend changes to its charter to the full Board based upon the evaluation results.

BOARD COMMITTEES

The Board of Directors has the following committees: Audit and Oversight, Compensation, Corporate Governance, Finance, and Executive. Each committee, except the Executive Committee, operates under a charter approved by the Board, which can be found on our website at www.wecenergygroup.com/govern/committee-comp.htm. With the exception of the Executive Committee, only independent directors serve on the standing committees.

Directors John Bergstrom and William Brodsky will complete their service as directors in 2019 and thus are not serving as nominees for re-election at the 2019 Annual Meeting. Mr. Brodsky currently serves as a member of the Finance Committee. Mr. Bergstrom currently chairs the Compensation Committee and is a member of the Audit and Oversight Committee.The Board is finalizing its plan for appointing a new Compensation Committee Chair.

Audit and Oversight

Members	Key Responsibilities
Thomas J. Fischer, Chair John F. Bergstrom Barbara L. Bowles Patricia W. Chadwick Danny L. Cunningham Henry W. Knueppel **2018 Meetings: 6**	• Oversee the integrity of the financial statements. • Oversee management compliance with legal and regulatory requirements. • Review the Company's environmental and compliance programs. • Review, approve, and evaluate the independent auditors' services. • Oversee the performance of the internal audit function and independent auditors. • Discuss risk management and major risk exposures and steps taken to monitor and control such exposures. • Establish procedures for the submission and treatment of complaints and concerns regarding the Company's accounting controls and auditing matters. • Prepare the audit committee report required by the SEC for inclusion in the proxy statement.

The Audit and Oversight Committee is a separately designated committee established in accordance with Section 3(a)(58)(A) of the Securities Exchange Act of 1934, as amended. The Audit and Oversight Committee consists solely of independent directors who meet the independence requirements of the SEC, NYSE and the Board's Corporate Governance Guidelines. In addition, the Board has determined that all of the members of the Audit and Oversight Committee are financially literate as required by NYSE rules and qualify as audit committee financial experts within the meaning of SEC rules.

Compensation

Members	Key Responsibilities
John F. Bergstrom, Chair Thomas J. Fischer Ulice Payne, Jr. **2018 Meetings: 6**	• Determine and annually review the Compensation Committee's compensation philosophy. • Oversee the development of competitive, performance-based executive and director compensation programs. • Review and approve the compensation paid to select employees, including certain senior officers and executive officers (including base salaries, incentive compensation, and benefits). • Establish and administer the CEO compensation package. • Set performance goals relevant to the CEO's compensation. • Annually evaluate CEO performance and determine compensation adjustments. • Oversee succession planning and assignments to key executive officers. • Prepare the report required by the SEC for inclusion in the proxy statement. • Review the results of the most recent stockholder advisory vote on compensation of the NEOs.

The Compensation Committee consists solely of independent directors who meet the independence requirements of the SEC, NYSE and the Board's Corporate Governance Guidelines.

The Compensation Committee is also charged with administering the compensation package of WEC Energy Group's non-management directors. The Compensation Committee meets with the Corporate Governance Committee annually to review the compensation package of WEC Energy Group's non-management directors and to determine the appropriate amount of such compensation.

The Compensation Committee, which has authority to retain advisers, including compensation consultants, at WEC Energy Group's expense, retained Frederic W. Cook & Co., Inc. ("FW Cook") to analyze and help develop the Company's executive compensation program, and to assess whether the compensation program is competitive and supports the Committee's objectives. FW Cook also assesses and provides recommendations on non-management director compensation, as discussed in more detail on page P-32. FW Cook is engaged solely by the Compensation Committee to provide executive compensation consulting services, and does not provide any additional services to the Company.

In connection with its retention of FW Cook, the Compensation Committee reviewed FW Cook's independence including: (1) the amount of fees received by FW Cook from WEC Energy Group as a percentage of FW Cook's total revenue; (2) FW Cook's policies and procedures designed to prevent conflicts of interest; and (3) the existence of any business or personal relationships that could impact independence. After reviewing these and other factors, the Compensation Committee determined that FW Cook is independent and the engagement did not present any conflicts of interest. FW Cook also determined that it was independent from the Company's management, which was confirmed in a written statement delivered to the Compensation Committee.

For more information regarding our executive and director compensation processes and procedures, please refer to "Compensation Discussion and Analysis" beginning on page P-35 and to "Director Compensation" beginning on page P-32, respectively.

Corporate Governance

Members	Key Responsibilities
Barbara L. Bowles, Chair Albert J. Budney, Jr. Curt S. Culver Henry W. Knueppel **2018 Meetings: 3**	• Establish and annually review the Corporate Governance Guidelines to verify that the Board is effectively performing its fiduciary responsibilities to stockholders. • Establish and annually review director candidate selection criteria. • Identify and recommend candidates to be named as nominees of the Board for election as directors. • Lead the Board in its annual review of the Board's performance.

The Corporate Governance Committee consists solely of independent directors who meet the independence requirements of the NYSE and the Board's Corporate Governance Guidelines.

Finance

Members	Key Responsibilities
Curt S. Culver, Chair William J. Brodsky Patrica W. Chadwick William M. Farrow III Ulice Payne, Jr. Mary Ellen Stanek	• Review and monitor the Company's current and long-range financial policies and strategies, including our capital structure and dividend policy. • Authorize the issuance of corporate debt within limits set by the Board. • Discuss policies and financial programs with respect to financial risk management. • Approve the Company's financial plan, including the capital budget.

2018 Meetings: 4

The Finance Committee consists solely of independent directors who meet the independence requirements of the NYSE and the Board's Corporate Governance Guidelines.

Executive

The Board also has an Executive Committee, which may exercise all powers vested in the Board except action regarding dividends or other distributions to stockholders, filling Board vacancies, and other powers which by law may not be delegated to a committee or actions reserved for a committee comprised of independent directors. The members of the Executive Committee are Gale E. Klappa (Chair), John F. Bergstrom, Barbara L. Bowles, Thomas J. Fischer, and Ulice Payne, Jr. The Executive Committee did not meet in 2018.

WHERE TO FIND MORE INFORMATION ON GOVERNANCE

You can find our Corporate Governance Guidelines, Code of Business Conduct, and other corporate governance materials, including WEC Energy Group's Restated Articles of Incorporation, Bylaws, Board committee charters and Board contact information, on the Corporate Governance section of our website at www.wecenergygroup.com/govern/governance.htm. You can request copies of these materials from the Corporate Secretary at the address provided below under "Communicating with the Board."

COMMUNICATING WITH THE BOARD

Correspondence may be sent to the directors, including the non-management directors, in care of the Corporate Secretary, Margaret C. Kelsey, at the Company's principal business office, 231 W. Michigan Street, PO Box 1331, Milwaukee, Wisconsin 53201. All communications received as set forth above will be opened by the Corporate Secretary for the sole purpose of confirming the contents represent a message to the Company's directors. Pursuant to instructions from the Board of Directors, all communication, other than advertising, promotion of a product or service, or patently offensive material, will be forwarded promptly to the addressee.

DIRECTOR COMPENSATION

Consistent with its charter, the Compensation Committee seeks to maintain a competitive director compensation program that enables the Company to attract and retain key individuals and to motivate them to help the Company achieve its short- and long-term goals. As such, the committee is responsible for reviewing key market-based trends in director compensation and benefits packages and for recommending changes to the Board, as appropriate, that will attract and retain quality directors. The Committee's charter authorizes it to engage consultants or advisors in connection with its review and analysis of director compensation. The Compensation Committee used FW Cook during 2018 for this purpose. Directors who are also employees of the Company do not receive additional compensation for service as a director.

2018 Compensation of the Board of Directors

The following table describes the components of the non-management director compensation program during 2018. The Compensation Committee believes that this program:

- is equitable based upon the work required of directors serving an entity of the Company's size and scope, and
- ties the majority of director compensation to stockholder interests because the value of the equity awards fluctuates depending upon the Company's stock price.

Compensation Element	2018 Non-Management Director Compensation Program
Annual Cash Retainer	$100,000, which may be deferred at the director's option
Annual Equity Retainer	$135,000 in restricted stock, which vests one year from grant date
Annual Committee Chair Fees	
• Audit and Oversight	$20,000 paid in $5,000 quarterly increments
• Compensation	$15,000 paid in $3,750 quarterly increments
• Corporate Governance	$15,000 paid in $3,750 quarterly increments
• Finance	$15,000 paid in $3,750 quarterly increments
Board and Committee Meeting Fees	None
Stock Ownership Guideline	Ownership of common stock or deferred stock units that have a value equal to five times the annual cash retainer for non-management directors to be satisfied within five years of joining the Board

Insurance is also provided by the Company for director liability coverage, fiduciary and employee benefit liability coverage, and travel accident coverage for director travel on Company business. The premiums paid for this insurance are not included in the amounts reported in the table below.

The Company reimburses directors for all out-of-pocket travel expenses. These reimbursed amounts are not reflected in the table below.

Deferred Compensation Plan. Non-management directors may defer all or a portion of their cash fees pursuant to the Directors' Deferred Compensation Plan. Directors have two investment options in the plan - the Company's phantom stock measurement fund or a prime rate fund. The value of the phantom stock measurement fund appreciates or depreciates based upon market performance of the Company's common stock, and it also grows through the accumulation of reinvested dividend equivalents. Deferral amounts are credited in the name of each participating director to accounts on the books of WEC Energy Group that are unsecured and are payable only in cash at the time elected by the director. Deferred amounts will be paid out of general corporate assets or the assets of the Wisconsin Energy Corporation 2014 Rabbi Trust discussed later in this proxy statement.

Legacy Charitable Awards Program. Directors elected prior to January 1, 2007 participate in a Directors' Charitable Awards Program under which the Company intends to contribute up to $100,000 per year for 10 years to one or more charitable organizations chosen by each participating director, including employee directors, following the director's death. Charitable donations under the program will be paid out of general corporate assets. Directors derive no financial benefit from the program, and all income tax deductions accrue solely to the Company. The tax deductibility of these charitable donations may mitigate the net cost to the Company. The Directors' Charitable Awards Program has been eliminated for any new directors elected after January 1, 2007. Directors already participating as of that date are Messrs. Bergstrom, Culver, Fischer, Klappa, and Payne, and Mmes. Bowles and Chadwick.

Director Compensation Table. The following table summarizes the total compensation received by each of WEC Energy Group's non-management directors during 2018.

Name	Fees Earned or Paid In Cash ($)	(1) Stock Awards ($)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)	Total ($)
John F. Bergstrom	115,000	135,000	—	—	—	21,947	271,947
Barbara L. Bowles	115,000	135,000	—	—	—	20,608	270,608
William J. Brodsky	100,000	135,000	—	—	—	—	235,000
Albert J. Budney, Jr.	100,000	135,000	—	—	—	—	235,000
Patricia W. Chadwick	100,000	135,000	—	—	—	30,110	265,110
Curt S. Culver	115,000	135,000	—	—	—	21,689	271,689
Danny L. Cunningham	100,000	135,000	—	—	—	—	235,000
William M. Farrow III	100,000	135,000	—	—	—	—	235,000
Thomas J. Fischer	120,000	135,000	—	—	—	21,947	276,947
Henry W. Knueppel	100,000	135,000	—	—	—	—	235,000
Allen L. Leverett (2)	—	—	—	—	—	—	—
Ulice Payne, Jr.	100,000	135,000	—	—	—	15,901	250,901
Mary Ellen Stanek	100,000	135,000	—	—	—	—	235,000

(1) Other than Mr. Cunningham (2,175 shares), Mr. Farrow (2,114 shares), and Mr. Leverett (23,248 shares), each director listed in this table held 4,828 shares of restricted stock as of the close of business on December 31, 2018.

(2) Effective October 10, 2018, Mr. Leverett resigned his position as President of WEC Energy Group but continues to serve as a member of the Board. Mr. Leverett did not receive any non-management director compensation during 2018. All compensation that Mr. Leverett received during 2018 for serving as an executive officer is reported in the "Summary Compensation Table" on page P-52.

Fees Earned or Paid in Cash. The amounts reported in the Fees Earned or Paid in Cash column include annual cash-based retainers for each non-management director and applicable annual committee chair fees earned during 2018 regardless of whether such retainers and fees were paid in cash or deferred.

Stock Awards. On January 2, 2018, each non-management director (other than Mr. Leverett) received his or her 2018 annual equity retainer in the form of restricted stock equal to a value of $135,000. The amounts reported in the Stock Awards column reflect the aggregate grant date fair value, as computed in accordance with Financial Accounting Standards Board Accounting Standards Codification ("FASB ASC") Topic 718, excluding estimated forfeitures, of the restricted stock awarded. Each reported restricted stock award vests in full one year from the grant date.

All Other Compensation. All amounts reported in the All Other Compensation column represent costs for the Directors' Charitable Awards Program. See "Legacy Charitable Awards Program" above for additional information.

2019 Compensation of the Board of Directors

In December 2018, the Compensation Committee completed its annual review of director compensation and determined that, based upon research provided by FW Cook, total non-management director compensation was consistent with the market median. As a result, the Compensation Committee concluded and the Board agreed that it was appropriate for 2019 Board compensation to remain unchanged from the approved 2018 levels.

PROPOSAL 2: ADVISORY VOTE TO APPROVE COMPENSATION OF THE NAMED EXECUTIVE OFFICERS

Pursuant to Section 14A of the Securities Exchange Act of 1934, the Company seeks your advisory vote on the approval of the compensation paid to our named executed officers (commonly referred to as "Say-on-Pay") as described in the Compensation Discussion and Analysis and the related tables included in this proxy statement. Approval, on a non-binding, advisory basis, of the compensation of the named executed officers requires the affirmative vote of a majority of the votes cast in person or by proxy at the Meeting. Presuming a quorum is present, shares not voted, whether by broker non-vote, abstention, or otherwise, have no effect on the outcome of this matter. Because your vote is advisory, it will not be binding on the Board or the Company. However, the Compensation Committee will review the voting results and take them into consideration when making future decisions regarding executive compensation.

As described in the Compensation Discussion and Analysis on pages P-35 through P-51 of this proxy statement, the Compensation Committee has structured the Company's executive compensation program with the following objectives in mind:

- offer a competitive, performance-based plan;
- enable the Company to attract and retain key individuals;
- reward achievement of the Company's short-term and long-term goals; and
- align with the interest of the Company's stockholders and customers.

As described in this proxy statement, the Company believes that the compensation paid to our named executed officers in 2018 was well-tailored to achieve these objectives, tying a significant portion of total pay to performance and aligning the interests of the named executed officers with those of stockholders and customers. We encourage you to carefully review the Compensation Discussion and Analysis and related tables included in this proxy statement, which describe in greater detail WEC Energy Group's compensation philosophy and programs, as well as the 2018 compensation levels, in connection with approval of the following resolution:

> "RESOLVED, that the stockholders approve, on an advisory basis, the compensation paid to the Company's named executive officers as disclosed in the Proxy Statement for the 2019 Annual Meeting."

The Board of Directors recommends that you vote "FOR" the advisory vote on Executive Compensation.

COMPENSATION DISCUSSION AND ANALYSIS

The following discussion provides an overview and analysis of our executive compensation program, including the role of the Compensation Committee of our Board, the elements of our executive compensation program, the purposes and objectives of these elements, and the manner in which we established the compensation of our named executive officers ("NEOs") for fiscal year 2018.

References to “we,” “us,” “our,” "Company," and “WEC Energy Group” in this discussion and analysis mean WEC Energy Group, Inc. and its management, as applicable.

EXECUTIVE SUMMARY

Overview

The primary objective of our executive compensation program is to provide a competitive, performance-based plan that enables the Company to attract and retain key individuals and to reward them for achieving both the Company’s short-term and long-term goals without creating an incentive for our NEOs to take excessive risks. Our program has been designed to provide a level of compensation that is strongly dependent upon the achievement of short-term and long-term goals that are aligned with the interests of our stockholders and customers. To that end, a substantial portion of pay is at risk, and generally, the value will only be realized upon strong corporate performance.

2018 Business Highlights

During 2018, we continued to make excellent progress in our efforts to integrate employees, merge and improve business processes, and consolidate IT infrastructure following our acquisition of Integrys Energy Group in June 2015. At the same time, the Company achieved solid results and continued to create long-term value for our stockholders and customers by focusing on the following:

- World-class reliability
- Operating efficiency
- Employee safety
- Financial discipline
- Exceptional customer care

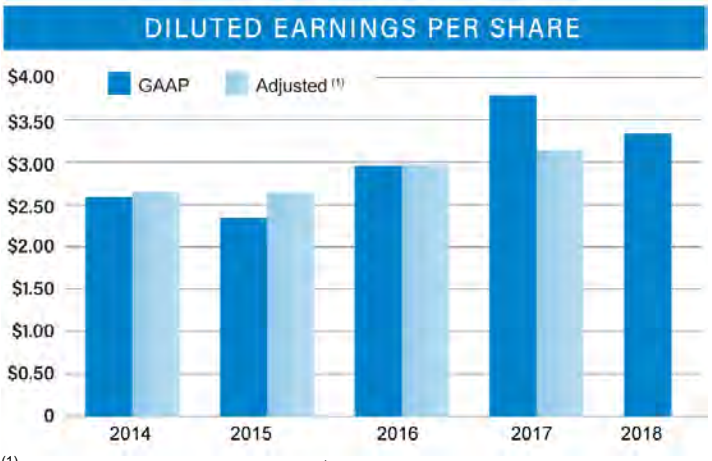
In addition, the seamless continuity in leadership provided by our senior executive management team following Allen Leverett’s unexpected illness in October 2017 resulted in solid earnings and cash flow generation for the Company in 2018.

Commitment to Stockholder Value Creation. Financially, WEC Energy Group again delivered solid earnings growth, generated strong cash flow, and increased the dividend for the 15th consecutive year. In January 2018, the Board raised the quarterly dividend 6.25% to $0.5525 per share, equivalent to an annual rate of $2.21 per share. In January 2019, the Board increased the quarterly dividend 6.8% to $0.59 per share, which is equivalent to an annual rate of $2.36 per share, in line with our plan to maintain a dividend payout ratio of 65% to 70% of earnings. Overall, the Company also turned in strong performances in customer satisfaction and network reliability during 2018.

Specific Company achievements during 2018 include:

2018 Financial Highlights

- WEC Energy Group delivered solid earnings growth again, generated strong cash flow, and increased the dividend for the 15th consecutive year.
- We achieved fully diluted earnings per share of $3.34. (2)
- Each of our regulated utility subsidiaries earned its allowed rate of return.
- We returned approximately $697.3 million to WEC Energy Group stockholders through dividends.
- Our common stock traded at a then all-time high of $75.48 on December 12, 2018.
- In January 2019, the Board raised the quarterly dividend to $0.59 per share, which is equivalent to an annual dividend rate of $2.36 per share.



(1) For 2017, excludes a one-time $0.65 per share gain related to a revaluation of our deferred taxes as a result of the Tax Cuts and Jobs Act of 2017. For 2016, 2015, and 2014, excludes costs of $0.01, $0.30, and $0.06 per share, respectively, related to our acquisition of Integrys. See Appendix A on P-79 for a full GAAP reconciliation and an explanation of why we believe the presentation of adjusted earnings per share is relevant and useful to investors.

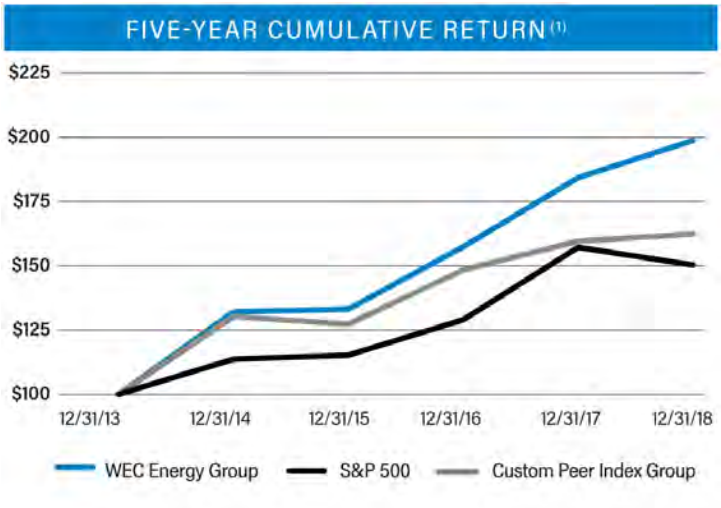
2018 Performance Highlights

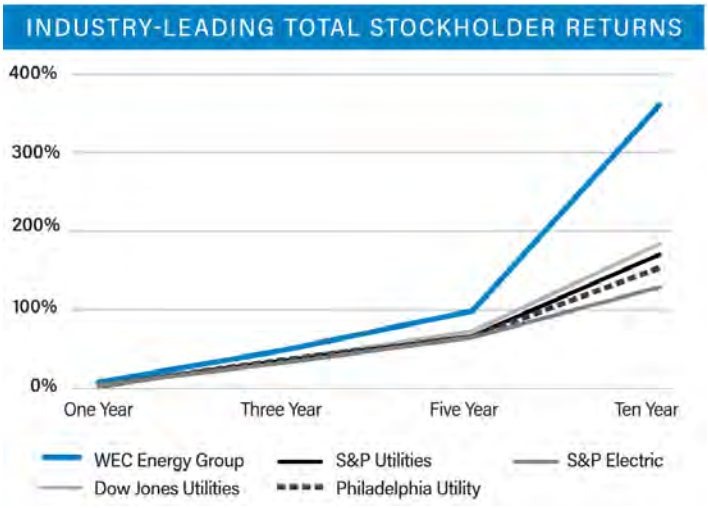
- WEC Energy Group was again recognized in 2018 by Corporate Responsibility Magazine as one of the 100 best corporate citizens in America.
- PA Consulting Group named We Energies the most reliable utility in the Midwest for the eighth year in a row.
- Set a new long-term goal to reduce carbon dioxide emissions below 2005 levels by 80% by 2050.
- Closed nearly 1,500 megawatts of older, less efficient coal-fired generation.
- Spent $263.1 million with qualified women-, minority-, and veteran- or service disabled- owned businesses, the highest spending with diverse suppliers in the Company's history.(2)
- Wisconsin Public Service Corporation ("WPSC") was named as a 2018 Most Trusted Utility Brand by Market Strategies International.
- All major utility subsidiaries either met or exceeded our overall customer satisfaction targets.(2)
- Continued to grow the Company's non-utility energy infrastructure segment, acquiring majority interests in three different wind farms with a total investment of approximately $587 million. Filed with the Public Service Commission of Wisconsin for approval for WPSC to partner with Madison Gas & Electric on two major solar projects in Wisconsin, where WPSC would own 100 megawatts of each project.

(2) This measure is a component of our short-term incentive compensation program.

Long-Term Stockholder Returns

Over the past decade, WEC Energy Group has consistently delivered among the best total returns in the industry and did so again in 2018.





(1) The Five-Year Cumulative Return Chart 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. For information about the Custom Peer Index Group, see "Performance Graph" in the Company's 2018 Annual Report.

Source: Bloomberg; assumes all dividends are reinvested and returns are compounded daily.

Consideration of 2018 Stockholder Advisory Vote and Stockholder Outreach

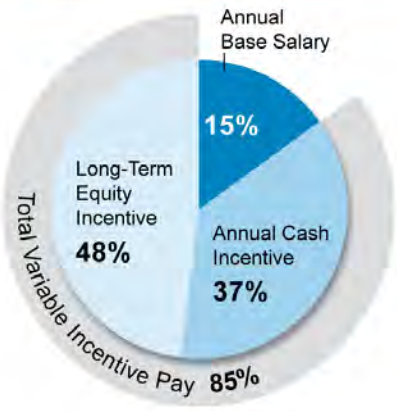
At the 2018 Annual Meeting of Stockholders, the Company’s stockholders approved the compensation of our named executive officers with 94% of the votes cast. The Compensation Committee considered this outcome as well as the feedback received during meetings we again held with several of our institutional stockholders. During 2018, we held dedicated sessions with stockholders representing approximately 27.1% of the Company’s outstanding common stock about our governance and compensation practices. The Compensation Committee is always looking for ways to refine our compensation program. However, in light of the significant stockholder support our executive compensation program received in 2018 and the payout levels under our performance-based program for 2018, the Compensation Committee believes that the current compensation program is competitive, aligned with our financial and operational performance, and in the best interests of the Company, stockholders, and customers.

COMPONENTS OF OUR EXECUTIVE COMPENSATION PROGRAM

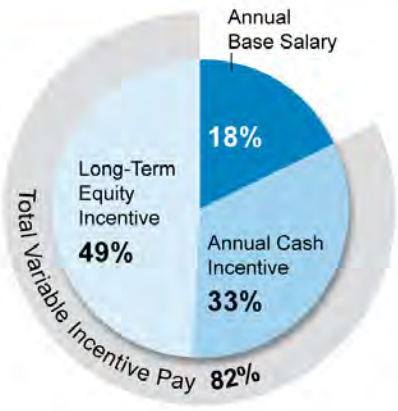
We have three primary elements of total direct compensation: (1) base salary; (2) annual incentive awards; and (3) long-term incentive awards consisting of a mix of performance units, stock options, and restricted stock. The Compensation Committee again retained Frederic W. Cook & Co., Inc. ("FW Cook") as its independent compensation consultant to advise the Compensation Committee with respect to our executive compensation program. The Compensation Committee generally relied on the recommendations of FW Cook as it developed the 2018 program.

As shown in the charts below, 85% of Mr. Klappa's 2018 total direct compensation and an average of 82% of the other NEOs' 2018 total direct compensation is tied to Company performance and is not guaranteed.

CEO 2018 TOTAL DIRECT COMPENSATION MIX



OTHER NEOs 2018 TOTAL DIRECT COMPENSATION MIX



In addition to the components of total direct compensation identified above, our retirement programs are another important component of our compensation program.

To the extent feasible, we believe it is important that the Company's compensation program not dilute the interests of current stockholders. Therefore, we currently use open-market purchases to satisfy our benefit plan obligations, including the exercise of stock options and vesting of restricted stock.

This Compensation Discussion and Analysis contains a more detailed discussion of each of the above components for 2018, including FW Cook's recommendations with respect to each component.

Compensation Governance and Practices

The Compensation Committee annually reviews and considers the Company's compensation policies and practices to ensure our executive compensation program aligns with our compensation philosophy. Highlighted below is an overview of our current compensation practices.

What We Do

- Our compensation program focuses on key Company results (financial, safety, customer satisfaction, diversity) that are aligned with our strategic goals.
- A substantial portion of compensation is at risk and tied to Company performance.
- The compensation program has a long-term orientation aligned with stockholder interests.
- The Compensation Committee retains an independent compensation consultant to help design the Company's compensation program and determine competitive levels of pay.
- The Compensation Committee's independent compensation consultant reviews competitive employment market data from two general industry surveys and a comparison group of companies similar to WEC Energy Group.
- We have implemented a clawback policy that provides for the recoupment of incentive-based compensation. (page P-49)
- Annual incentive-based compensation contains multiple, pre-established performance metrics aligned with stockholder and customer interests. (page P-42)
- The Performance Unit Plan award payouts (including dividend equivalents) are based on stockholder return as compared to an appropriate peer group and Additional Performance Measure(s), selected by the Compensation Committee. (page P-45)
- The Performance Unit Plan requires a separation from service following a change in control for award vesting to occur. (page P-48)
- Equity award and other benefit plan obligations are satisfied through open-market purchases of WEC Energy Group common stock.
- Meaningful stock ownership levels are required for senior executives. (page P-49)
- Ongoing engagement with investors takes place to ensure that compensation practices are responsive to stockholder interests.
- We prohibit hedging and pledging of WEC Energy Group common stock. (page P-49)
- We prohibit entry into any new arrangements that obligate the Company to pay directly or reimburse individual tax liability for benefits provided by the Company. (page P-50)
- We prohibit repricing of stock options without stockholder approval.

Competitive Benchmarking

As a general matter, we believe the labor market for WEC Energy Group executive officers is consistent with that of general industry. Although we recognize our business is focused on the energy services industry, our goal is to have an executive compensation program that will allow us to be competitive in recruiting the most qualified candidates to serve as executive officers of the Company, including individuals who may be employed outside of the energy services industry. Further, in order to retain top performing executive officers, we believe our compensation practices must be competitive with those of general industry.

To confirm that our annual executive compensation is competitive with the market, FW Cook reviewed the compensation data obtained from Willis Towers Watson's 2018 Executive Compensation Data Bank as well as similar data from Aon Hewitt. FW Cook also analyzed the compensation data from a peer group of 18 companies similar to WEC Energy Group in size and business model. The methodology used by FW Cook to determine the peer group of companies is described below.

FW Cook started with U.S. companies in the Standard & Poor's database, and then limited those companies to the same line of business as WEC Energy Group as indicated by the Global Industry Classification Standards. This list of companies was then further limited to companies with revenues between $2.5 billion and $22.8 billion (approximately one-third to three times the size of WEC Energy Group's revenues), and that were within a reasonable size range in various other measures such as operating income, total assets, total employees, and market capitalization. From this list, FW Cook selected companies similar in overall size to WEC Energy Group with consideration given to companies that met one or more of the following criteria:

- Diversified, technically sophisticated utility operations (e.g., multiple utilities, electric utilities);
- Minimal non-regulated business; and/or
- Operates in the Midwest.

These criteria resulted in a comparison group of 18 companies with median revenues and market capitalization of approximately $9.6 billion and $17 billion, respectively.

The comparison group utilized for purposes of 2018 compensation includes the same companies as the previous year's comparison group, and was comprised of the 18 companies listed below.

- Alliant Energy Corporation
- Ameren Corporation
- American Electric Power Company
- CMS Energy Corporation
- CenterPoint Energy
- Consolidated Edison, Inc.
- DTE Energy Co.
- Edison International
- Entergy Inc.
- Eversource Energy
- FirstEnergy Corp.
- NiSource Inc.
- PG&E Corporation
- PPL Corp.
- Pinnacle West Capital Corp.
- SCANA Corporation
- The Southern Company
- Xcel Energy Inc.

The Compensation Committee approved this comparison group.

DETERMINATION OF MARKET MEDIAN

In order to determine the "market median" for our NEOs, FW Cook recommended that the survey data from Willis Towers Watson and Aon Hewitt receive a 75% weighting and the comparison group of 18 companies receive a 25% weighting. The Compensation Committee agreed with this recommendation. The survey data received a higher weighting because we consider the labor market for our executives to be consistent with that of general industry. Using this methodology, FW Cook recommended, and the Compensation Committee approved, the appropriate market median for each of our NEOs.

The comparison of each component of compensation with the appropriate market median when setting the compensation levels of our NEOs generally drives the allocation of cash versus non-cash compensation and short-term versus long-term incentive compensation.

DETERMINATION OF MESSRS. KLAPPA'S AND KUESTER'S 2018 COMPENSATION

As we previously reported, Mr. Klappa agreed to resume the role of CEO of WEC Energy Group after Mr. Leverett suffered a stroke in October 2017. In recognition of his continued service and leadership while Mr. Leverett continued to recover from his stroke, the Compensation Committee, in consultation with FW Cook regarding the appropriate pay level for Mr. Klappa under the circumstances, determined that the aggregate amount of Mr. Klappa's direct compensation (as opposed to each individual component of direct compensation) should be substantially the same as it was at the time of his retirement in 2016. Therefore, the Compensation Committee set Mr. Klappa's 2018 annual base salary at $1,425,000 and his annual incentive plan target at 120% of base salary, the same target he was receiving at the time of his retirement in 2016. The Committee then awarded Mr. Klappa long-term incentive compensation at a level that was lower than he was receiving in 2016, so that the total value of direct compensation Mr. Klappa received would be substantially equal to his 2016 compensation levels and at or near the 2018 median for overall compensation.

Mr. Kuester had an ongoing consulting relationship with the Company following his retirement in 2013 pursuant to which he periodically advised on WEC Energy Group's capital program. Due to Mr. Leverett's medical leave beginning in October 2017, and in order to provide for continuity and dedicated oversight of the Company's significant capital program during Mr. Leverett's absence, Mr. Kuester's consulting duties significantly increased at the end of 2017. This substantial increase in duties resulted in a significant increase in payments under his prior consulting agreement, which remained in effect until Mr. Kuester agreed to return to the Company and assume the position of Senior Executive Vice President effective March 1, 2018. The Compensation Committee determined that the aggregate amount of Mr. Kuester's direct compensation as Senior Executive Vice President should be substantially the same as it was at the time he retired as Executive Vice President from the Company in 2013, recognizing that he was assuming additional responsibilities from those he held prior to his retirement in 2013. As a result, the Committee set Mr. Kuester's 2018 annualized base salary and target award under the STPP at $765,000 and 80% of base salary, respectively. Mr. Kuester's long-term incentive compensation was set slightly below the level he was receiving when he retired in 2013. Mr. Kuester's responsibilities include oversight of the development and execution of the Company's capital plan.

MR. LEVERETT'S 2018 COMPENSATION

We compensated Mr. Leverett pursuant to the Company's standard medical leave policy until he resigned as President of WEC Energy Group effective October 10, 2018. At the time 2018 compensation levels were being determined, we did not know how long Mr. Leverett would be on medical leave, but fully expected that he would return to the role of Chief Executive Officer. As a result, the Compensation Committee evaluated Mr. Leverett's 2017 performance up to the start of his medical leave in October 2017, and determined that he had earned a standard cost-of-living base salary increase of 3% for 2018. In addition, Mr. Leverett's target award level under the STPP remained unchanged at 125% of base salary. In accordance with the Company's standard benefit plans and policies applicable to all management employees, Mr. Leverett received an award under the STPP pro-rated to his number of days of service in 2018 prior to his resignation as President. In addition, Mr. Leverett received a customary long-term incentive award in accordance with the Company's standard practices for those on medical leave. Upon his resignation as President, Mr. Leverett began receiving payments under other applicable benefit plans of the Company in which he was already a participant and under which he was eligible to receive payments.

ANNUAL BASE SALARY

The annual base salary component of our executive compensation program provides each executive officer with a fixed level of annual cash compensation. We believe that providing annual cash compensation through a base salary is an established market practice and is a necessary component of a competitive compensation program.

Based upon the market data analyzed by FW Cook, we generally target base salaries to be at or near the market median for each NEO. However, the Compensation Committee may, in its discretion, set base salaries at a different amount when the Compensation Committee deems it appropriate.

Actual salary determinations are made taking into consideration factors such as the relative levels of individual experience, performance, responsibility, and contribution to the results of the Company's operations. At the beginning of each year, our CEO develops a list of goals for WEC Energy Group and our employees to achieve during the upcoming year. At the end of the year, our CEO measures the performance of the Company against each stated goal and reports the results to the Board. The Compensation Committee then takes the Company's performance into consideration when establishing our CEO's compensation for the upcoming year. Our CEO undertakes a similar process with the NEOs, who develop individual goals related to the achievement of the Company's goals developed by our CEO. At the end of the year, each officer's performance is measured against these goals. Compensation recommendations and determinations for the upcoming year for each executive officer also take into consideration the level of such performance.

For information about Messrs. Klappa's, Kuester's and Leverett's base salary, see the discussion about each individual's compensation above.

With respect to the remaining NEOs, in December 2017, Mr. Klappa recommended an annual base salary to the Compensation Committee based upon a review of the market compensation data provided by FW Cook and the factors described above. The Compensation Committee approved the recommendations, which represented an average increase in annual base salary of approximately 3% for Messrs. Fletcher and Keyes, and Ms. Kelsey, and an increase in annual base salary of approximately 12% for Mr. Lauber.

In recognition of Mr. Fletcher's appointment to President of WEC Energy Group in October 2018, the Compensation Committee increased his annual base salary to $700,000.

Upon his appointment as Executive Vice President and Chief Financial Officer in April 2016, Mr. Lauber's base salary was initially set below market median because of how significant such an increase would have been in order to bring his salary at or near median. As we previously reported, the Compensation Committee's intent was to increase Mr. Lauber's salary in multiple steps to eventually move it to market median. In line with this intent, the Compensation Committee increased Mr. Lauber's base salary by 12% effective January 1, 2018, and again by 7.9% effective July 29, 2018, to provide an aggregate base salary of $600,000 in 2018, putting his salary at market median. The annual base salary of each NEO (other than Mr. Klappa, whose total direct compensation was determined as described above) was at or near the market median.

ANNUAL CASH INCENTIVE COMPENSATION

We provide annual cash incentive compensation through our Short-Term Performance Plan ("STPP"). The STPP provides for annual cash awards to NEOs based upon the achievement of pre-established stockholder-, customer-, and employee- focused objectives. All payments under the STPP are at risk. Payments are made only if performance goals are achieved, and awards may be less or greater than targeted amounts based upon actual performance. Payments under the STPP are intended to reward achievement of short-term goals that contribute to stockholder and customer value, as well as individual contributions to successful operations.

2018 Target Awards. Each year, the Compensation Committee approves a target level of compensation under the STPP for each of our NEOs. This target level of compensation is expressed as a percentage of base salary.

In October 2018, the target award level for Mr. Fletcher was increased to 90% of base salary in recognition of his appointment to President of WEC Energy Group. Therefore, Mr. Fletcher's STPP payout level reflects a 70% target level for nine months and a 90% target level for three months.

The year-end 2018 target awards for each NEO (other than Messrs. Klappa, Kuester and Leverett, who are discussed above) are set forth in the chart below.

Executive Officer	Target STPP Award as a Percentage of Base Salary
Mr. Lauber	80%
Mr. Fletcher	90%
Ms. Kelsey	70%
Mr. Keyes	75%

The target award levels of each officer named in the table above reflect median incentive compensation practices as indicated by the market data.

For 2018, the possible payout for any NEO ranged from 0% of the target award to 210% of the target award, based upon performance.

2018 Financial Goals under the STPP. The Compensation Committee adopted the 2018 STPP with a continued principal focus on financial results. In December 2017, the Compensation Committee approved WEC Energy Group's earnings per share (75% weight) and cash flow (25% weight) as the primary performance measures to be used in 2018. For those officers whose positions primarily relate to utility operations in Wisconsin (including Mr. Fletcher until he was appointed President of WEC Energy Group in October 2018) the Compensation Committee approved WEC Energy Group's earnings per share (25% weight) and cash flow (25% weight), as well as aggregate net income of WEC Energy Group's Wisconsin utility operations (50% weight), as the primary performance measures to be used in 2018. We believe earnings per share and cash flow are key indicators of financial strength and performance, and are recognized as such by the investment community. Utility net income is an important financial measure as it is an indicator of the return on equity earned by our utilities, and in order to meet our earnings per share targets it is important that our utilities earn at or close to their allowed rates of return.

In October 2018, the target award level for Mr. Fletcher was increased from 70% to 90% of base salary in recognition of his appointment to President of WEC Energy Group. Therefore, Mr. Fletcher's STPP payout level is based upon a combination of (i) WEC Energy Group's Wisconsin utility operations' performance against their 2018 performance goals and (ii) WEC Energy Group's performance against its 2018 performance goals.

In January 2018, the Compensation Committee approved the performance goals under the STPP for WEC Energy Group's earnings per share as set forth in the chart below.

Earnings Per Share Performance Goal	Earnings Per Share CAGR	Payout Level
$3.19	3.2%	25%
$3.21	3.9%	50%
$3.24	5.0%	100%
$3.26	5.5%	135%
$3.30	6.8%	200%

If the Company's performance falls between these levels, the payout level with respect to earnings per share is determined by interpolating on a straight line basis the appropriate payout level.

Although WEC Energy Group achieved earnings per share of $3.79 based on generally accepted accounting principles ("GAAP"), because this result included a one-time adjustment of $0.65 per share related to the impact of the Tax Cuts and Jobs Act of 2017 (the "Tax Legislation"), the Compensation Committee determined that the appropriate earnings per share measure on which to base the 2018 performance goals was WEC Energy Group's 2017 adjusted earnings per share of $3.14.

The Company's growth plan, which has been communicated to the public, calls for a long-term compound annual growth rate ("CAGR") in earnings per share of 5.0% to 7.0%. At the time the Compensation Committee was establishing targets for 2018, this CAGR was measured off a 2017 base of $3.09 per share, which represented the mid-point of the 2017 annual earnings guidance. We believe that this CAGR, plus our continued growth in dividends, supports a premium valuation as compared to the Company's peers. Therefore, the Compensation Committee tied the target (100%) payout level to achievement of the low end of the target CAGR range (5.0%), and the above-target payout level to achievement of a 5.5% CAGR. The Compensation Committee tied the maximum payout level (200%) to achievement of a 6.8% CAGR.

In January 2018, the Compensation Committee approved the initial performance goals under the STPP for WEC Energy Group's cash flow. At that time, management informed the Compensation Committee that it might recommend new cash flow

performance goals for consideration later in the year based upon the impact of the Tax Legislation and voluntary contributions to subsidiary pension plans. During 2018, WEC Energy Group returned $100 million to customers related to the impacts of the Tax Legislation and one of the Company's utility subsidiaries made a voluntary contribution of $60 million to its pension plan. As a result, in October 2018, the Compensation Committee revised the cash flow performance goals, which are set forth in the chart below ($ in millions).

Cash Flow	Payout Level
$1,700	25%
$1,750	50%
$1,800	100%
$1,850	135%
$1,950	200%

If the Company's performance falls between these levels, the payout level with respect to cash flow is determined by interpolating on a straight-line basis the appropriate payout level.

The Compensation Committee based the cash flow performance level goals on WEC Energy Group's funds from operations ("FFO"). FFO is calculated by taking "cash provided by operating activities" and eliminating certain accruals and other items related to capital spending. GAAP requires these items to be recorded as part of cash from operations, but management views them as related to the Company's capital expenditure program. The Compensation Committee believes that basing the cash flow performance goals on FFO provides a more accurate measurement of the cash generated by the Company's operations that is available for capital investment, which is the Company's primary driver for earnings growth. FFO is not a measure of financial performance under GAAP, and the Company's calculation may differ from similarly titled measures used by other companies or securities rating agencies.

In January 2018, the Compensation Committee approved the performance goals under the STPP for the Wisconsin utilities' net income (based upon WEC Energy Group's earnings per share performance goals) as set forth in the chart below ($ in millions).

Net Income	Weighted Return on Equity	Payout Level
$588	9.92%	25%
$593	10.00%	50%
$598	10.08%	100%
$603	10.16%	135%
$613	10.32%	200%

2018 Financial Performance under the STPP. In January 2019, the Compensation Committee reviewed our actual performance for 2018 against the financial and operational performance goals established under the STPP, subject to final audit.

WEC Energy Group's 2018 financial performance satisfied the maximum payout level established for earnings per share, cash flow, and net income for the Wisconsin utilities. WEC Energy Group's earnings per share were $3.34 for 2018. WEC Energy Group's cash flow, based on FFO, was $2,372 million, and the Wisconsin utilities' net income was $617 million for 2018. Our cash flow result is not a measure of financial performance under GAAP.

By satisfying the maximum payout level with respect to these financial measures, the NEOs earned 200% of the target award from the financial goal component of the STPP.

2018 WEC Energy Group Operational Goals and Performance under the STPP. Similar to prior years, in December 2017 and January 2018, the Compensation Committee also approved operational performance measures and targets under the STPP. Annual incentive awards could be increased or decreased by up to 10% of the actual award based upon WEC Energy Group's performance in the operational areas of customer satisfaction (5% weight), safety (2.5% weight), and supplier and workforce diversity (2.5% weight). The Compensation Committee recognizes the importance of strong operational results to the success of the Company and has identified these three operational areas in particular as being critical to that success.

The Compensation Committee measures customer satisfaction levels based upon the results of surveys that an independent third party conducts of customers who had direct contact with our utilities during the year, which measure (i) customers' satisfaction with the respective utility overall, and (ii) customers' satisfaction with respect to the particular transactions with the applicable utility. Safety is measured based upon performance against the number of lost time injuries and OSHA recordable incidents, as well as the number of Near Miss/Unsafe Condition ("NMUC") Reports filed. NMUC reporting is designed to proactively identify and take action on potential safety risks before an incident occurs (unsafe conditions); and to learn from near-miss incidents that have occurred, but did not result in an injury or damage.

The operational performance measures are based upon recommendations from management and take into consideration both current year performance and our longer-term objective of achieving top quartile performance of all of our principal utilities. The Compensation Committee reviews management's recommendations and may make adjustments to the performance measures if it feels changes are necessary. The following table provides the operational goals approved by the Compensation Committee for 2018, as well as WEC Energy Group's performance against these goals:

Operational Measure	Below Goal	Goal	Above Goal	Final Result
Customer Satisfaction Percentage of "Highly Satisfied":	-5.00%	0.00%	+5.00%	
Company	<75.7%	75.7% - 78.8%	>78.8%	79.2%
Transaction	<79.2%	79.2% - 82.2%	>82.2%	82.4%
Safety:	-2.50%	0.00%	+2.50%	
Lost Time Injury - Incidents	>67	39 - 67	<39	55
OSHA Recordable - Incidents	>206	135 - 206	<135	193
Near Miss / Unsafe Condition Reports	<20,100	20,100 - 23,992	>23,992	25,146
Diversity:	-2.50%	0.00%	+2.50%	
Supplier ($ in Millions)	<196.1	196.1 - 231.7	>231.7	263.1
Workforce - Assessment	Not Met	Met	Exceeded	Met

Based on the operational results listed in the table above, WEC Energy Group's performance with respect to operational goals generated a 7.08% increase to the compensation awarded under the STPP for 2018.

2018 Wisconsin Utilities Operational Goals and Performance under the STPP. For those officers whose positions in 2018 primarily related to utility operations in Wisconsin, STPP awards could be increased or decreased by up to 10% based upon performance in the operational areas of customer satisfaction (5% weight), safety (2.5% weight), and supplier diversity (1.25% weight) for WEC Energy Group's Wisconsin utility operations, as well as WEC Energy Group's performance in the operational area of workforce diversity (1.25% weight).

The Compensation Committee measures customer satisfaction levels based upon the results of surveys that an independent third party conducts of customers who had direct contact with our Wisconsin utilities during the year, which measure (1) customers' satisfaction with the specific Wisconsin utility overall, and (2) customers' satisfaction with respect to their particular transactions with their specific utility. Safety is measured based upon performance against the number of lost time injuries and OSHA recordable incidents, as well as the number of NMUC Reports filed.

The following table provides the operational goals approved by the Compensation Committee for 2018 for WEC Energy Group's Wisconsin utility operations, as well as the Company's performance against these goals:

Operational Measure	Below Goal	Goal	Above Goal	Final Result
Customer Satisfaction Percentage of "Highly Satisfied":	-5.00%	0.00%	+5.00%	
Company	<78.8%	78.8% - 81.7%	>81.7%	81.8%
Transaction	<82.0%	82.0% - 85.1%	>85.1%	84.7%
Safety:	-2.50%	0.00%	+2.50%	
Lost Time Injury - Incidents	>25	13 - 25	<13	31
OSHA Recordable - Incidents	>105	65 - 105	<65	109
Near Miss / Unsafe Condition Reports	<14,538	14,538 - 17,792	>17,792	15,012
Diversity:	-2.50%	0.00%	+2.50%	
Supplier ($ in Millions)	<105.0	105.0 - 120.0	>120.0	138.2
Workforce - Assessment	Not Met	Met	Exceeded	Met

Based upon the operational results listed in the table above, the Wisconsin utilities' performance with respect to operational goals generated a 2.08% increase to the compensation awarded under the STPP for 2018.

The Compensation Committee retains the right to exercise discretion in adjusting awards under the STPP when it deems appropriate, but did not factor individual contributions into determining the amount of the awards for the NEOs for 2018. Because the Company's performance against the financial and operational goals resulted in significant STPP awards in 2018, the Compensation Committee determined that no further adjustments based upon individual contributions or otherwise were appropriate.

Based upon the Company's performance against the financial and operational goals established by the Compensation Committee, Mr. Klappa received annual incentive cash compensation under the STPP of $3,541,124 for 2018. This represented 248% of his annual base salary. Messrs. Lauber, Fletcher, Kuester, and Keyes, and Ms. Kelsey, each received annual cash incentive compensation for 2018 under the STPP equal to 166%, 157%, 198%, 155%, and 145% of their respective annual base salaries, representing 207.08% of the target award for each officer, other than Mr. Fletcher, whose incentive compensation payout was 204.05% of his target award. Mr. Fletcher's STPP payout is based upon a combination of (i) the number of days he served as President of WEC Energy Group with a target award of 90% of base pay multiplied by WEC Energy Group's payout level of 207.08% of his target award and (ii) the number of days he served as President of WEC Energy Group's Wisconsin utility operations with a target award of 70% of base salary multiplied by WEC Energy Group's Wisconsin utility operations' payout level of 202.08% of his target award. For additional information about Messrs. Klappa's, Kuester's, and Leverett's receipt of incentive compensation under the STPP, see "Determination of Messrs. Klappa's and Kuester's 2018 Compensation" and "Mr. Leverett's 2018 Compensation" on page P-40.

LONG-TERM INCENTIVE COMPENSATION

The Compensation Committee administers our 1993 Omnibus Stock Incentive Plan, amended and restated effective January 1, 2016, which is a stockholder-approved, long-term incentive plan designed to link the interests of our executives and other key employees to creating long-term stockholder value. It allows for various types of awards tied to the performance of our common stock, including stock options, stock appreciation rights, and restricted stock. The Compensation Committee also administers the WEC Energy Group Performance Unit Plan, under which the Compensation Committee may award performance units. The Compensation Committee primarily uses (1) performance units, including dividend-equivalents, (2) stock options, and (3) restricted stock to deliver long-term incentive opportunities.

Performance Units. Each year, the Compensation Committee makes annual grants of performance units under the Performance Unit Plan. The performance units are designed to provide a form of long-term incentive compensation that aligns the interests of management with those of a typical utility stockholder who is focused not only on stock price appreciation but also on dividends. Payouts are based upon the Company's level of "total stockholder return" (stock price appreciation plus reinvested dividends) in comparison to a peer group of companies over a three-year performance period, and may be adjusted based upon the Company's performance against one or more Additional Performance Measures. The performance units are settled in cash.

Selection of Additional Performance Measure(s). "Additional Performance Measure" is defined as the performance criterion or criteria (if any) that the Compensation Committee selects, in its sole discretion, based upon the attainment of specific levels of performance by WEC Energy Group. Performance units vest in an amount between 0% and 175% of the target award based upon WEC Energy Group's comparative total stockholder return over a three-year performance period. However, the vesting percentage may be adjusted based upon WEC Energy's performance against the Additional Performance Measure(s). The Additional Performance Measure(s), if any, must be selected by the Compensation Committee at the beginning of the three-year performance period. For each year during the performance period, the Compensation Committee will select the target(s) for the Additional Performance Measure(s) and the potential adjustment to the vesting percentage for that year based upon achievement of the Additional Performance Measure(s) relative to the selected target(s). The actual adjustment, if any, to the vesting percentage based upon the Additional Performance Measure(s) will be determined annually. In no event will any adjustment cause the vesting percentage over the three-year performance period to be less than zero.

Short-Term Dividend Equivalents. We increase the number of unvested performance units as of any date that we declare a cash dividend on our common stock by the amount of short-term dividend equivalents a participant is entitled to receive. Short-term dividend equivalents are calculated by multiplying (a) the number of unvested performance units held by a plan participant as of the related dividend record date by (b) the amount of cash dividend payable by the Company on a share of common stock; and (c) dividing the result by the closing price for a share of the Company's common stock on the dividend payment date. In effect, short-term dividend equivalents are credited and accumulated as reinvested dividends on each performance unit so that the performance units and accumulated dividends will be paid out at the end of the three-year performance period, rather than paying out the dividend equivalents annually on unearned performance units.

Short-term dividend equivalents are treated as additional unvested performance units and are subject to the same vesting, forfeiture, payment, termination, and other terms and conditions as the original performance units to which they relate. In addition, outstanding short-term dividend equivalents are treated as unvested performance units for purposes of calculating future short-term dividend equivalents.

Stock Options. Each year, the Compensation Committee also makes annual stock option grants as part of our long-term incentive program. These stock options have an exercise price equal to the fair market value of our common stock on the date of grant and expire on the 10th anniversary of the grant date. Since management benefits from a stock option award only to the extent our stock price appreciates above the exercise price of the stock option, stock options align the interests of management with those of our stockholders in attaining long-term stock price appreciation.

Restricted Stock. The Compensation Committee also awards restricted stock as part of the long-term incentive plan, consistent with market practice. Similar to performance units, restricted stock aligns the interests of management with a typical utility stockholder who is focused on stock price appreciation and dividends.

Aggregate 2018 Long-Term Incentive Awards. Generally, when establishing the target value of long-term incentive awards and the appropriate mix of performance units, stock options, and restricted stock for each NEO, the Compensation Committee reviews the market compensation data and analysis provided by FW Cook. Based upon FW Cook's analysis, for 2018 the Compensation Committee determined that the long-term incentive awards would be weighted 65% performance units, 20% stock options, and 15% restricted stock for Messrs. Lauber, Fletcher, Leverett, and Keyes, and Ms. Kelsey. Target values also were presented to and approved by the Compensation Committee in December 2017.

With respect to Messrs. Klappa and Kuester, after consultation with FW Cook, the Compensation Committee determined that their long-term incentive awards would be weighted 80% restricted stock and 20% stock options. At the time, the Committee recognized that Messrs. Klappa's and Kuester's tenure with the Company would be significantly shorter than the other executive officers. Since the vesting percentage of performance units is based upon WEC Energy Group's total stockholder return over a three-year period, the Compensation Committee did not believe that performance units would accurately reflect the contributions of Messrs. Klappa and Kuester to the success of the Company over a shorter period of time.

Based upon the market data provided by FW Cook, we target the long-term incentive award to be at or near the market median value of long-term incentive compensation for each executive officer's position. All of the NEOs' long-term incentive awards were within this target range for 2018. For additional information on Messrs. Klappa's, Kuester's and Leverett's awards, see "Determination of Messrs. Klappa's and Kuester's 2018 Compensation" and "Mr. Leverett's 2018 Compensation" on page P-40.

2018 Stock Option Grants. In December 2017, the Compensation Committee approved the grant of stock options to each of our NEOs (other than Mr. Kuester) and established an overall pool of options that were granted to approximately 200 other employees. The option grants to the NEOs (other than Mr. Kuester) were made effective January 2, 2018, the first trading day of 2018. The options were granted with an exercise price equal to the average of the high and low prices reported on the NYSE for shares of WEC Energy Group common stock on the grant date. The options were granted in accordance with our standard practice of making annual stock option grants effective on the first trading day of each year, and the timing of the grants was not tied to the timing of any release of material information. The Compensation Committee granted Mr. Kuester's stock options effective March 1, 2018, the date he commenced service as Senior Executive Vice President of WEC Energy Group.

These stock options have a term of 10 years and vest 100% on the third anniversary of the date of grant. The vesting of the stock options may be accelerated in connection with a change in control or an executive officer's termination of employment under certain circumstances. See "Potential Payments upon Termination or Change in Control" beginning on page P-63 for additional information. Subject to the limitations of the 1993 Omnibus Stock Incentive Plan, the Compensation Committee has the power to amend the terms of any option (with the participant's consent). However, the Committee may not reduce the exercise price of existing options or cancel outstanding options and grant replacement options having a lower exercise price without stockholder approval.

For purposes of determining the appropriate number of options to grant to a particular NEO, the value of an option was determined based upon the Black-Scholes option pricing model. We use the Black-Scholes option pricing model for purposes of the compensation valuation. The following table provides the number of options granted to each NEO in 2018:

Executive Officer	Options Granted
Mr. Klappa	115,960
Mr. Lauber	26,465
Mr. Fletcher	16,055
Mr. Kuester	50,055
Ms. Kelsey	18,380
Mr. Leverett	120,925
Mr. Keyes	24,825

For financial reporting purposes, the stock options granted on January 2, 2018 had a grant date fair value of $8.68 per option for Messrs. Lauber, Leverett, and Keyes, and Ms. Kelsey, and a grant date fair value of $6.84 for Messrs. Klappa and Fletcher, who are considered to be "retirement eligible." The stock options granted on March 1, 2018 to Mr. Kuester, who is also "retirement eligible," had a grant date fair value of $5.95. The options granted to Messrs. Klappa, Fletcher and Kuester are presumed to have a shorter expected life, which results in a lower option value.

2018 Restricted Stock Awards. In December 2017, the Compensation Committee also approved the grant of restricted stock to each of our NEOs (other than Mr. Kuester) and established an overall pool of restricted stock that was granted to approximately 200 other employees. The grants to the NEOs were also made effective January 2, 2018 (other than Mr. Kuester). Mr. Kuester's grant of restricted stock was made effective March 1, 2018. Other than the shares granted to Messrs. Klappa and Kuester, the restricted stock vests in three equal annual installments beginning on January 2, 2019. The shares of restricted stock granted to Messrs. Klappa and Kuester vest in full on the one year anniversary of the grant date, reflecting the shorter tenure the Committee expected for Messrs. Klappa and Kuester.

The vesting of the restricted stock may be accelerated in connection with a termination of employment due to a change in control, death or disability, or by action of the Compensation Committee. Messrs. Klappa's and Kuester's restricted stock also fully vested if they resigned for "good reason," defined as a material diminution in their authority, duties or responsibilities, including, but not limited to, the Company's appointment of a successor Chief Executive Officer. The Compensation Committee wanted to appropriately incentivize Messrs. Klappa and Kuester to return to the Company while Mr. Leverett recovered from his stroke. See "Potential Payments upon Termination or Change in Control" beginning on page P-63 for additional information. Tax withholding obligations related to vesting may be satisfied, at the option of the executive officer, by withholding shares otherwise deliverable upon vesting or by cash. The NEOs have the right to vote the restricted stock and to receive cash dividends when the Company pays a dividend to our stockholders.

For purposes of determining the appropriate number of shares of restricted stock to grant to a particular NEO, the Compensation Committee used a value of $68.39 per share. This value was based upon the volume weighted price of WEC Energy Group's common stock for the ten trading days beginning on December 4, 2017, and ending on December 15, 2017. The Compensation Committee uses the volume-weighted price in order to minimize the impact of day-to-day volatility in the stock market.

The measurement period is customarily close to the grant date in order to shorten the timeframe between the calculation of the awards and the actual grant date. The following table provides the number of shares of restricted stock granted to each NEO in 2018:

Executive Officer	Restricted Stock Granted
Mr. Klappa	57,008
Mr. Lauber	2,439
Mr. Fletcher	1,479
Mr. Kuester	24,609
Ms. Kelsey	1,695
Mr. Leverett	11,145
Mr. Keyes	2,289

2018 Performance Units. In 2018, the Compensation Committee granted performance units to each of our NEOs (other than Messrs. Klappa and Kuester) and approved a pool of performance units that were granted to approximately 200 other employees. With respect to the 2018 performance units, the amount of the benefit that ultimately vests will be dependent upon the Company's total stockholder return over a three-year period ending December 31, 2020, as compared to the total stockholder return of the custom peer group described below. Total stockholder return is the calculation of total return (stock price appreciation plus reinvestment of dividends) based upon an initial investment of $100 and subsequent $100 investments at the end of each quarter during the three-year performance period. However, the vesting percentage may be adjusted based upon WEC Energy Group's performance against the Additional Performance Measure. For the 2018 performance unit awards, the Compensation Committee selected performance against the weighted average authorized return on equity of all WEC Energy Group's utility subsidiaries as the Additional Performance Measure.

Upon vesting, the performance units will be settled in cash in an amount determined by multiplying the number of performance units that have vested by the closing price of the Company's common stock on the last trading day of the performance period.

The 2018 performance unit peer group against which WEC Energy Group's performance will be measured includes:

- Alliant Energy Corporation
- Ameren Corporation
- American Electric Power Company
- CMS Energy Corporation
- Consolidated Edison, Inc.
- DTE Energy Co.
- Duke Energy Corp.
- Edison International
- Eversource Energy
- Evergy, Inc.
- FirstEnergy Corp.
- NiSource Inc.
- OGE Energy Corp.
- PG&E Corporation
- Pinnacle West Capital Corp.
- SCANA Corporation
- The Southern Company
- Xcel Energy Inc.

The peer group is chosen by the Compensation Committee, based upon management's recommendation and with the concurrence of FW Cook. This peer group was chosen because we believe these companies are similar to WEC Energy Group in terms of business model and long-term strategies, with a primary focus on regulated utility operations rather than a non-regulated business model. There is significant overlap between the performance unit peer group and the comparison group developed by FW Cook for purposes of benchmarking compensation levels. However, there are several companies that are different among the two groups because FW Cook places significant weight on the financial metrics of the companies included in its comparison group, whereas we focus more on operational measures for the performance unit peer group.

The required percentile ranking for total stockholder return and the applicable vesting percentage are set forth in the chart below.

Performance Percentile Rank	Vesting Percent
< 25th Percentile	0%
25th Percentile	25%
Target (50th Percentile)	100%
75th Percentile	125%
90th Percentile	175%

If the Company's rank is between the benchmarks identified above, the vesting percentage will be determined by interpolating on a straight line basis the appropriate vesting percentage. Unvested performance units generally are immediately forfeited upon a NEO's cessation of employment with WEC Energy Group prior to completion of the three-year performance period. However, the performance units will vest immediately at the target 100% rate upon the termination of the NEO's employment (1) by reason of disability or death or (2) after a change in control of WEC Energy Group. In addition, a prorated number of performance units (based upon the target 100% rate) will vest upon the termination of employment of the NEO by reason of retirement prior to the end of the three-year performance period.

In response to feedback we received from stockholders, the Compensation Committee amended the Performance Unit Plan, effective January 1, 2017, to provide for an Additional Performance Measure. For the 2018 performance unit awards, the Additional Performance Measure is the weighted average authorized return on equity ("ROE") of all WEC Energy Group's utility subsidiaries. In order for WEC Energy Group to meet its earnings per share targets, it is important that our utilities earn at or close to their allowed rates of return. The Company's performance against this measure may increase or decrease the vesting percentage of the performance units up to 10% over the three-year performance period. For 2018, the ROE targets and potential adjustments were set as follows:

If Actual Annual ROE is	The Annual Adjustment is	ROE Ranges
≤ 20 bp below the Authorized ROE	+ 3.33%	≥ 9.76%
21 - 30 bp below the Authorized ROE	0%	9.66% - 9.75%
> 30 bp below the Authorized ROE	(3.33)%	< 9.66%

These are the same ROE targets and potential adjustments that we used in connection with the Additional Performance Measure for the 2017 performance unit awards, which was the first year we included an Additional Performance Measure. WEC Energy Group's utility subsidiaries achieved a weighted average authorized ROE of 10.38% for 2018. This resulted in a 3.33% increase in the vesting percentage of the performance units awarded in January 2018 and January 2017. For purposes of determining the appropriate number of performance units to grant to a particular NEO, the Compensation Committee used a value of $68.39 per unit, the same value used for the restricted stock granted in January 2018.

The following table provides the number of performance units granted to each NEO effective January 2, 2018, at the 100% target level:

Executive Officer	Performance Units Granted
Mr. Klappa	—
Mr. Lauber	10,570
Mr. Fletcher	6,415
Mr. Kuester	—
Ms. Kelsey	7,340
Mr. Leverett	48,305
Mr. Keyes	9,915

2018 Payouts under Previously Granted Long-Term Incentive Awards. In 2016, the Compensation Committee granted performance unit awards to participants in the Performance Unit Plan. The terms of the performance units granted in 2016 were substantially similar to those of the performance units granted in 2018 described above, except that the 2016 performance units did not have an Additional Performance Measure. The required percentile ranks for total stockholder return and related vesting schedule were identical to that of the 2018 performance units.

Payouts under the 2016 performance units were based upon our total stockholder return for the three-year performance period ended December 31, 2018 against the same group of peer companies used for the 2018 performance unit awards.

Our total stockholder return was at the 78th percentile of the peer group for the three-year performance period ended December 31, 2018, resulting in the performance units vesting at a level of 134.3%. The actual payouts were determined by multiplying the number of vested performance units by the closing price of our common stock ($69.26) on December 31, 2018, the last trading day of the performance period. The actual payout to each NEO (other than Messrs. Klappa and Kuester, and Ms. Kelsey, who did not have any 2016 performance units outstanding) is reflected in the "Option Exercises and Stock Vested for Fiscal Year 2018" table.

COMPENSATION RECOUPMENT POLICY

Accountability is a fundamental value of WEC Energy Group. To reinforce this value through the Company's executive compensation program, the Compensation Committee has adopted a clawback policy that provides for the recoupment of incentive-based compensation in the event WEC Energy Group is required to prepare an accounting restatement due to material noncompliance with any financial reporting requirement under the securities laws (other than restatements permitted as a result of changes in accounting principles or interpretation). Pursuant to the policy, the Compensation Committee will recover from any current or former executive officer who has received incentive-based compensation during the three-year period preceding the date on which WEC Energy Group is required to prepare the accounting restatement, any portion of the incentive-based compensation paid in excess of what would have been paid to the executive officer under the restated financial results. The Company may also recover incentive-based compensation if an executive officer's employment is terminated for cause, or the executive officer violates a noncompetition or other restrictive covenant.

STOCK OWNERSHIP GUIDELINES

The Compensation Committee believes that an important adjunct to the long-term incentive program is significant stock ownership by officers who participate in the program, including the NEOs. Accordingly, the Compensation Committee has implemented stock ownership guidelines requiring officers who participate in the long-term incentive program to hold an amount of Company common stock and other equity-related Company securities that varies depending upon such officer's level.

In addition to shares owned outright, holdings of each of the following are included in determining compliance with our stock ownership guidelines: restricted stock; WEC Energy Group phantom stock units held in the Executive Deferred Compensation Plan; WEC Energy Group stock held in WEC Energy Group's 401(k) plans; performance units at target; and shares held in a brokerage account, jointly with an immediate family member or in a trust.

The guidelines require each executive officer, including the NEOs, to acquire (generally within five years of appointment as an executive officer) and hold common stock and other equity-related securities of the Company having a minimum fair market value ranging from 250% to 600% of base salary. The Compensation Committee believes these stock ownership guidelines discourage unreasonable risk taking by Company officers.

The Compensation Committee annually reviews whether executive officers are in compliance with these guidelines. The last review was completed in October 2018. The Compensation Committee determined that all NEOs are in compliance, or making sufficient progress towards compliance, with these guidelines.

PROHIBITION ON HEDGING AND PLEDGING

WEC Energy Group's Corporate Securities Trading Policy prohibits the use of any strategies or products, including derivatives and short-selling techniques, to hedge against potential changes in the value of WEC Energy Group's common stock. The policy, which is applicable to all directors and employees of the Company, including the NEOs, also prohibits the holding of WEC Energy Group securities in a margin account, as well as the pledging of WEC Energy Group securities as collateral for a loan.

LIMITED TRADING WINDOWS

Officers, including the NEOs, other key employees, and the Company's directors may only transact in WEC Energy Group securities during approved trading windows after satisfying mandatory pre-clearance requirements.

RETIREMENT PROGRAMS

We also maintain retirement plans in which our NEOs participate: a defined benefit pension plan of the cash balance type, a supplemental pension plan, individual letter agreements with some of the NEOs, and a 401(k) plan. We believe our retirement plans are a valuable benefit in the attraction and retention of our employees, including the NEOs. We believe that providing a foundation for long-term financial security for our employees, beyond their employment with the Company, is a valuable component of our overall compensation program which will inspire increased loyalty and improved performance. For more information about our retirement plans, see "Pension Benefits at Fiscal Year-End 2018" and "Retirement Plans."

Messrs. Klappa and Kuester had previously retired from the Company. For information regarding certain payments made to Messrs. Klappa and Kuester in connection with such retirements, see “Pension Benefits at Fiscal Year-End 2018.”

OTHER BENEFITS, INCLUDING PERQUISITES

We provide our executive officers, including the NEOs, with employee benefits and a limited number of perquisites. Except as specifically noted elsewhere in this proxy statement, the employee benefits programs in which executive officers participate (which provide benefits such as medical coverage, retirement benefits, annual contributions to a qualified savings plan, and moving and relocation costs) are generally the same programs offered to substantially all of the Company’s management employees.

The perquisites made available to executive officers include financial planning, membership in a service that provides health care and safety management when traveling outside the United States, reimbursement for expenses related to annual physical exam costs not covered by insurance, and limited spousal travel for business purposes. The Company also pays periodic dues and fees for club memberships for certain of the NEOs and other designated officers.

We customarily review market data regarding executive perquisite practices on an annual basis. Following our acquisition of Integrys Energy Group, the Compensation Committee undertook a thorough review of WEC Energy Group’s perquisite practices with FW Cook. At that time, FW Cook recommended to the Compensation Committee that the Company retain its package of perquisites. For 2018, the Compensation Committee again reviewed our package of perquisites with FW Cook and decided not to make any changes. WEC Energy Group has a legacy group of executives who are still eligible for gross-ups. We reimburse those executives for taxes paid on income attributable to the financial planning benefits provided to the executives only if the executive uses the Company’s identified preferred provider, AYCO. We believe the use of the preferred financial adviser provides administrative benefits and eases communication between Company personnel and the financial adviser.

We pay periodic dues and fees for certain club memberships as we have found that the use of these facilities helps foster better customer and community relationships. Officers, including the NEOs, are expected to use clubs for which the Company pays dues primarily for business purposes. We do not pay any additional expenses incurred for personal use of these facilities, and officers are required to reimburse the Company to the extent that it pays for any such personal use. The total annual club dues are included in the "Summary Compensation Table." We do not permit personal use of the airplane available to the Company. We do allow spousal travel if an executive’s spouse is accompanying the executive on business travel and the airplane is not fully utilized by Company personnel. There is no incremental cost to the Company for this travel, other than the reimbursement for taxes paid on imputed income attributable to the executives for this perquisite, as the airplane cost is the same regardless of whether or not an executive’s spouse travels. Any tax reimbursement is subject to the Company’s Tax Gross-Up Policy discussed below.

In addition, each of our executive officers is eligible to participate in an officer life insurance benefit. If an executive officer chooses to participate, upon such officer’s death while employed by the Company, a benefit is paid to his or her designated beneficiary in an amount equal to the value of three times the officer’s base salary at the time of death.

TAX GROSS-UP POLICY

The Compensation Committee adopted a formal policy that prohibits entry into any contract, agreement, or arrangement with any officer of the Company that obligates the Company to pay directly or reimburse the officer for any portion of the officer’s individual tax liability for benefits provided by the Company. Excluded from this policy are (1) agreements or arrangements entered into prior to December 2014 when the policy was adopted, (2) agreements or arrangements entered into prior to, and assumed by the Company in connection with, any merger or acquisition, or (3) plans or policies applicable to Company employees generally.

This policy formalized the Compensation Committee’s policy that had been in place since July 2011 to eliminate tax gross-ups on perquisites provided by the Company to its officers (except to officers who were already receiving gross-ups as of July 2011). Of the NEOs, Messrs. Lauber and Leverett were receiving gross-ups from the Company prior to July 2011.

In light of Mr. Klappa's retirement in May 2016, and subsequent re-appointment as CEO in 2017, and Mr. Kuester's retirement in January 2013 and subsequent appointment as Senior Executive Vice President in 2018, both Mr. Klappa and Mr. Kuester are deemed new employees for benefits purposes and are not eligible to receive gross-ups.

SEVERANCE BENEFITS AND CHANGE IN CONTROL

Several years ago, the Compensation Committee determined that it would no longer offer severance and change in control benefits in employment agreements. Therefore, Messrs. Klappa, Lauber, Kuester, and Keyes, and Ms. Kelsey, have not entered into an employment agreement that provides for these benefits. However, they are eligible to participate in the Company's Severance Pay Plan. Prior to that time, each of Messrs. Fletcher and Leverett entered into an employment agreement with the Company, which includes severance and change in control provisions. For a discussion of the severance and change in control benefits available under these agreements, and to our executive officers generally, see "Potential Payments upon Termination or Change in Control."

In addition, our supplemental pension plan provides that in the event of a change in control, participants will be entitled to a lump sum payment of amounts due under the plan if employment is terminated within 18 months of the change in control.

IMPACT OF PRIOR COMPENSATION

The Compensation Committee does not believe it is appropriate to consider the amounts realized or realizable from prior incentive compensation awards when establishing future levels of short-term and long-term incentive compensation.

SECTION 162(m) OF THE INTERNAL REVENUE CODE

Certain components of the Company's compensation program were designed to ensure the deductibility of compensation based on tax regulations in effect at the time the compensation was awarded, including Section 162(m). Section 162(m) of the Internal Revenue Code limits the deductibility of certain executives' compensation that exceeds $1,000,000 per year. For tax years prior to 2018, compensation over $1,000,000 per year could be deducted by the Company if such compensation was performance-based under Section 162(m) and issued through a plan that had been approved by stockholders. Starting with compensation awarded in 2018, the Tax Cuts and Jobs Act of 2017 eliminated the performance-based compensation exception under 162(m) for compensation over $1,000,000.

COMPENSATION COMMITTEE REPORT

The Compensation Committee has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management and, based on such review and discussions, the Compensation Committee recommended to the Board that the Compensation Discussion and Analysis be included in this proxy statement.

The Compensation Committee

John F. Bergstrom, Committee Chair
Thomas J. Fischer
Ulice Payne, Jr.

EXECUTIVE COMPENSATION TABLES

The following table summarizes total compensation awarded to, earned by, or paid to WEC Energy Group's Chief Executive Officer ("CEO"), Chief Financial Officer ("CFO"), and each of the other individuals identified in the table below (the "NEOs").

SUMMARY COMPENSATION TABLE

Name and Principal Position	Year	Salary ($)	Bonus ($)	(5) Stock Awards ($)	(6) Option Awards ($)	(7) Non-Equity Incentive Plan Compensation ($)	(8) Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	(9)(10) All Other Compensation ($)	Total ($)	Total Without Change in Pension Value ($)
Gale E. Klappa[1] Executive Chairman	2018	1,425,000	—	3,763,383	793,166	3,541,124	158,568	181,752	9,862,993	9,862,993
	2017	2,225,000	—	250,012	—	—	2,529,057	27,102	5,031,171	2,593,579
	2016	589,043	—	7,427,755	816,752	1,179,632	925,719	210,435	11,149,336	10,250,269
Scott J. Lauber Senior Executive Vice President, CFO and Treasurer	2018	574,711	—	858,790	229,716	952,418	22,857	76,186	2,714,678	2,714,678
	2017	467,321	—	534,890	137,001	764,441	93,343	66,124	2,063,120	1,977,525
	2016	351,784	—	158,886	38,371	513,010	65,818	38,116	1,165,985	1,103,685
J. Kevin Fletcher[1] President and Chief Executive Officer	2018	504,733	—	521,122	109,816	792,078	739,652	52,100	2,719,501	2,023,895
	2017	436,800	—	535,648	137,199	633,095	1,198,310	44,062	2,985,114	1,800,225
	2016	411,345	—	336,818	81,425	606,866	671,274	39,869	2,147,597	1,482,133
Frederick D. Kuester[2] Senior Executive Vice President	2018	638,481	—	1,476,294	297,827	1,267,350	33,485	266,998	3,980,435	3,980,435
Margaret C. Kelsey[2] Executive Vice President, General Counsel and Corporate Secretary	2018	515,000	—	596,445	159,538	746,535	41	88,223	2,105,782	2,105,782
Allen L. Leverett[3] Former President	2018	980,235	—	3,924,592	1,049,629	2,400,040	2,595,024	390,357	11,339,877	8,783,390
	2017	1,161,000	—	4,034,706	1,033,362	3,018,251	4,224,896	170,022	13,642,237	9,437,265
	2016	941,667	—	2,939,251	769,144	2,162,593	4,549,812	140,512	11,502,979	6,963,294
J. Patrick Keyes[4] Former Executive Vice President, Strategy	2018	579,676	—	805,647	215,481	900,309	137,664	75,557	2,714,334	2,609,178
	2017	562,792	—	920,228	235,718	885,736	122,780	73,214	2,800,468	2,682,669
	2016	546,400	—	889,965	215,067	904,320	111,973	73,034	2,740,759	2,630,909

Note: In order to show the effect that the year-over-year change in pension value had on total compensation, as determined under applicable SEC rules, we have included an additional column to show total compensation minus the change in pension value. The amounts reported in the Total Without Change in Pension Value column may differ substantially from the amounts reported in the Total column required under SEC rules and are not a substitute for total compensation. Total Without Change in Pension Value represents total compensation, as determined under applicable SEC rules, minus the change in pension value reported in the Change in Pension Value and Nonqualified Deferred Compensation Earnings column. The change in pension value is subject to many external variables, such as interest rates, that are not related to Company performance. Therefore, we do not believe a year-over-year change in pension value is helpful in evaluating compensation for comparative purposes.

(1) Mr. Klappa retired as CEO on May 1, 2016, but continued to serve as the Non-Executive Chairman of the Company's Board. After Mr. Leverett suffered a stroke in October 2017, the Company's Board appointed Mr. Klappa Chairman and CEO while Mr. Leverett recovered from his stroke. Mr. Klappa served in these roles until February 1, 2019, at which time he began serving as Executive Chairman. Mr. Fletcher, who was appointed to serve as President of WEC Energy Group on October 9, 2018, was appointed President and Chief Executive Officer of the Company effective February 1, 2019.

(2) Mr. Kuester, who was named Senior Executive Vice President effective March 1, 2018, and Ms. Kelsey, who was named Executive Vice President, General Counsel and Corporate Secretary effective January 1, 2018, became named executive officers in 2018. Therefore, no information has been provided for 2016 or 2017 for either officer.

(3) Mr. Leverett, who had been recovering from a stroke he suffered in October 2017, resigned as President effective October 10, 2018. Pursuant to the Company's standard medical leave policy, Mr. Leverett received 100% of his annual base salary until March 26, 2018, at which time he started receiving 80% of his base pay. Upon his resignation as President, Mr. Leverett began receiving payments under certain benefit plans of the Company, which are reflected in the All Other Compensation column. Mr. Leverett's annual incentive award under the STPP, included in the Non-Equity Incentive Plan Compensation column, was prorated to reflect the number of days Mr. Leverett served as President in 2018.

(4) Mr. Keyes resigned as Executive Vice President, Strategy and from his other officer positions with WEC Energy Group and its subsidiaries effective September 14, 2018, but remained an employee of the Company until January 4, 2019 to help transition his responsibilities.

(5) The amounts reported reflect the aggregate grant date fair value, as computed in accordance with FASB ASC Topic 718 excluding estimated forfeitures, of performance units and/or restricted stock awarded to each NEO in the respective year for which such amounts are reported. The amounts reported for the performance units are based upon the probable outcome as of the grant date of associated performance and market conditions, and are consistent with our estimate, as of the grant date, of aggregate compensation cost to be recognized over the three-year performance period. The actual value received by the executives from these awards may range from $0 to greater than the reported amounts, depending upon the Company's performance and the executive's number of additional years of service with the Company.

The value of the performance unit awards as of the grant date, assuming achievement of the highest level of performance and excluding any performance units resulting from short-term dividend equivalents and the Additional Performance Measure, for each of Messrs. Lauber, Fletcher, Leverett, and Keyes, and Ms. Kelsey, is $1,221,145, $741,084, $5,580,512, $1,145,426, and $847,963, respectively, for the 2018 awards. The value of the performance unit awards as of the grant date, assuming achievement of the highest level of performance and excluding any performance units resulting from short-term dividend equivalents and the Additional Performance Measure, for each of Messrs. Lauber, Fletcher, Leverett, and Keyes, is $760,647, $761,697, $5,736,862, and $1,308,597, respectively, for the 2017 awards. See "Option Exercises and Stock Vested For Fiscal Year 2017" for the amount of the actual payout with respect to the 2016 award of performance units. Mr. Klappa's 2016 grant of performance units vested pursuant to the terms of the Company's Performance Unit Plan upon his retirement on May 1, 2016. Not included are the performance unit awards resulting from short-term dividend equivalents and/or the Additional Performance Measure that may increase or, in the case of the Additional Performance Measure, decrease these amounts.

(6) The amounts reported reflect the aggregate grant date fair value, as computed in accordance with FASB ASC Topic 718 excluding estimated forfeitures, of options awarded to each NEO in the respective year for which such amounts are reported. The actual value received by the executives from these awards may range from $0 to greater than the reported amounts, depending upon Company performance. In accordance with FASB ASC Topic 718, we made certain assumptions in our calculation of the grant date fair value of the stock options. See "Stock Options" in Note 1(k) -- Stock-Based Compensation, in the Notes to Consolidated Financial Statements in our 2018 Annual Report on Form 10-K for a description of these assumptions. For 2018, the assumptions made in connection with the valuation of the stock options are the same as described in Note 1(k), except that the expected life of the options is 7.7 years for Messrs. Lauber, Leverett, and Keyes, and Ms. Kelsey, 4.3 years for Messrs. Klappa and Fletcher, and 3.5 years for Mr. Kuester. Mr. Kuester's options were granted effective March 1, 2018 as compared to the grant date of January 2, 2018 for the other NEOs. The change in the expected life of the options as set forth in Note 1(k) resulted from the fact that Messrs. Klappa, Fletcher, and Kuester are "retirement eligible" as of the grant date, and Messrs. Lauber, Leverett, and Keyes, and Ms. Kelsey, were not, whereas the assumption described in Note 1(k) is a weighted average of all option holders.

(7) Consists of the annual incentive compensation earned under WEC Energy Group's STPP.

(8) The amounts reported for 2018, 2017, and 2016 reflect the aggregate change in the actuarial present value of each applicable NEO's accumulated benefit under all defined benefit plans from December 31, 2017 to December 31, 2018, December 31, 2016 to December 31, 2017, and December 31, 2015 to December 31, 2016, respectively. The amounts reported for all three years also include above-market earnings on compensation that is deferred by the NEOs into the Prime Rate Fund under WEC Energy Group's Executive Deferred Compensation Plan. Above-market earnings represent the difference between the interest rate used to calculate earnings under the Plan and 120% of the applicable federal long-term rate prescribed by the Internal Revenue Code. The amounts earned for 2018 are shown below.

Name	Change in Pension Value ($)	Non-Qualified Deferred Compensation Earnings ($)	Total ($)
Gale E. Klappa	—	158,568	158,568
Scott J. Lauber	—	22,857	22,857
J. Kevin Fletcher	695,606	44,046	739,652
Frederick D. Kuester	—	33,485	33,485
Margaret C. Kelsey	—	41	41
Allen L. Leverett	2,556,487	38,537	2,595,024
J. Patrick Keyes	105,156	32,508	137,664

For 2018, 2017, and 2016, the applicable discount rate used to value pension plan liabilities moved from 3.65% to 4.30%, 4.15% to 3.65%, and 4.45% to 4.15%, respectively. As the discount rate decreases, the Company's pension funding obligation increases, and vice versa. The changes in the actuarial present values of the NEOs' pension benefits do not constitute cash payments to the NEOs.

The pension values reported represent only WEC Energy Group's obligation of the aggregate change in the actuarial present value of each NEO's accumulated benefit under all defined benefit plans. Messrs. Klappa, Fletcher, Kuester, and Leverett are entitled to receive pension benefits from prior employers. To the extent such prior employers are unable to pay their pension obligations, WEC Energy Group may be obligated to pay the total amount.

(9) During 2018, each NEO received financial planning services and the cost of an annual physical exam; Messrs. Klappa, Lauber, Fletcher, and Leverett were provided with membership in a service that provides healthcare and safety management when traveling outside the United States; Mr. Leverett received reimbursement for club dues. In 2018, the Company paid $78,181 for the lease of an apartment and related parking costs for Mr. Kuester as he transitioned from retirement back to Milwaukee, Wisconsin and into his new role as Senior Executive Vice President. Although Mr. Klappa utilized the benefit of spousal travel for business purposes in 2018, there was no associated cost to the Company as Mr. Klappa was not eligible to receive reimbursement for taxes paid on imputed income attributable to him for such travel.

(10) For Mr. Klappa, the amount reported in All Other Compensation for 2018 includes $23,453 attributable to WEC Energy Group's Directors' Charitable Awards Program in connection with Mr. Klappa's service on the Company's Board. See "Director Compensation" for a description of the Directors' Charitable Awards Program.

All Other Compensation for Messrs. Klappa, Lauber, Fletcher, Leverett, and Keyes, and Ms. Kelsey, for 2018 also consists of:

- Employer matching of contributions into the WEC Energy Group 401(k) plan in the amount of $11,000 for Messrs. Klappa, Lauber, Fletcher, and Keyes; $10,625 for Messrs. Kuester and Leverett; and $10,434 for Ms. Kelsey;
- Employer contributions into the WEC Energy Group 401(k) plan in the amount of $16,500 for Messrs. Klappa and Kuester, and Ms. Kelsey, and into the WEC Energy Group Non-Qualified Retirement Savings Plan in the amount of $69,000 for Mr. Klappa, $20,043 for Mr. Kuester, and $26,674 for Ms. Kelsey. These payments are in lieu of participation in the Company's pension plan;
- "Make-whole" payments under the Executive Deferred Compensation Plan that provides a match at the same level as the WEC Energy Group 401(k) plan (4% for up to 7% of wages) for all deferred salary and bonus not otherwise eligible for a match in the amounts of $46,000 for Mr. Klappa, $42,239 for Mr. Lauber, $33,700 for Mr. Fletcher, $16,914 for Ms. Kelsey, $143,089 for Mr. Leverett, and $46,557 for Mr. Keyes;
- Payments in the amount of $128,817 to Mr. Kuester under a previous consulting agreement with WEC Energy Group for services he provided in January and February 2018, prior to being named Senior Executive Vice President;
- Payments under a supplemental long-term benefit plan in the amount of $200,108 for Mr. Leverett; and
- Tax reimbursements or "gross-ups" for all applicable perquisites in the amounts of $7,202 and $14,454 for Messrs. Lauber and Leverett, respectively.

Other Information

In recognition of his appointment as President and Chief Executive Officer of WEC Energy Group in February 2019, Mr. Fletcher's 2019 annual base salary was increased to $1,004,000 and his target award under the STPP was increased to 125% of base salary. Additionally, in connection with Mr. Klappa's appointment as Executive Chairman in February 2019, his 2019 annual base salary and STPP target were set at $1,000,000 and 100% of base salary, respectively.

GRANTS OF PLAN-BASED AWARDS FOR FISCAL YEAR 2018

The following table shows additional data regarding incentive plan awards to the NEOs in 2018.

Name	Grant Date	Action Date [1]	Estimated Future Payouts Under Non-Equity Incentive Plan Awards [2]			Estimated Future Payouts Under Equity Incentive Plan Awards [3]			All Other Stock Awards: Number of Shares of Stock or Units [4]	All Other Option Awards [5]			Grant Date Fair Value of Stock and Option Awards
			Threshold ($)	Target ($)	Maximum ($)	Threshold (#)	Target (#)	Maximum (#)	(#)	Number of Securities Underlying Options (#)	Exercise or Base Price [6] ($/Sh)	Closing Market Price ($/Sh)	($)
Gale E. Klappa	1/18/18	—	427,500	1,710,000	3,591,000	—	—	—	—	—	—	—	—
	1/2/18	12/7/17	—	—	—	—	—	—	57,008	—	—	—	3,763,383
	1/2/18	12/7/17	—	—	—	—	—	—	—	115,960	66.015	65.77	793,166
Scott J. Lauber	1/18/18	—	114,980	459,920	965,832	—	—	—	—	—	—	—	—
	1/2/18	12/7/17	—	—	—	2,643	10,570	18,498	—	—	—	—	697,779
	1/2/18	12/7/17	—	—	—	—	—	—	2,439	—	—	—	161,011
	1/2/18	12/7/17	—	—	—	—	—	—	—	26,465	66.015	65.77	229,716
J. Kevin Fletcher	1/18/18	—	97,045	388,180	815,178	—	—	—	—	—	—	—	—
	1/2/18	12/7/17	—	—	—	1,604	6,415	11,226	—	—	—	—	423,486
	1/2/18	12/7/17	—	—	—	—	—	—	1,479	—	—	—	97,636
	1/2/18	12/7/17	—	—	—	—	—	—	—	16,055	66.015	65.77	109,816
Frederick D. Kuester	3/1/18	—	153,000	612,000	1,285,200	—	—	—	—	—	—	—	—
	3/1/18	2/23/18	—	—	—	—	—	—	24,609	—	—	—	1,476,294
	3/1/18	2/23/18	—	—	—	—	—	—	—	50,055	59.99	59.63	297,827
Margaret C. Kelsey	1/18/18	—	90,125	360,500	757,050	—	—	—	—	—	—	—	—
	1/2/18	12/7/17	—	—	—	1,835	7,340	12,845	—	—	—	—	484,550
	1/2/18	12/7/17	—	—	—	—	—	—	1,695	—	—	—	111,895
	1/2/18	12/7/17	—	—	—	—	—	—	—	18,380	66.015	65.77	159,538
Allen L. Leverett	1/18/18	—	289,743	1,158,973	2,433,843	—	—	—	—	—	—	—	—
	1/2/18	12/7/17	—	—	—	12,076	48,305	84,534	—	—	—	—	3,188,855
	1/2/18	12/7/17	—	—	—	—	—	—	11,145	—	—	—	735,737
	1/2/18	12/7/17	—	—	—	—	—	—	—	120,925	66.015	65.77	1,049,629
J. Patrick Keyes	1/18/18	—	108,689	434,757	912,990	—	—	—	—	—	—	—	—
	1/2/18	12/7/17	—	—	—	2,479	9,915	17,351	—	—	—	—	654,539
	1/2/18	12/7/17	—	—	—	—	—	—	2,289	—	—	—	151,108
	1/2/18	12/7/17	—	—	—	—	—	—	—	24,825	66.015	65.77	215,481

(1) Other than with respect to Mr. Kuester, on December 7, 2017, the Compensation Committee awarded the 2018 option, restricted stock, and performance unit grants effective the first trading day of 2018 (January 2, 2018). On February 23, 2018 the Compensation Committee awarded Mr. Kuester option and restricted stock grants effective March 1, 2018.

(2) Non-equity incentive plan awards consist of annual incentive awards under WEC Energy Group's STPP. For a more detailed description of the STPP, see the Compensation Discussion and Analysis.

(3) Consists of performance units awarded under the WEC Energy Group Performance Unit Plan. WEC Energy Group's Performance Unit Plan provides for short-term dividend equivalents. The number of performance units awarded will be increased as of any date that WEC Energy Group declares a cash dividend on its common stock by the amount of short-term dividend equivalents awarded. In effect, short-term dividend equivalents will be credited and accumulated as reinvested dividends on each performance unit so that the performance units and accumulated dividends will be paid out at the end of the performance units' three-year performance period, contingent upon the Company's performance. Therefore, the number of performance units reported at each of the threshold, target, and maximum levels in this table will increase by the number of short-term dividend equivalents earned. In addition, these amounts do not reflect any potential impact of the Company's performance against the Additional Performance Measure. For a more detailed description of the performance units, short-term dividend equivalents and Additional Performance Measure, see the Compensation Discussion and Analysis.

(4) Consists of restricted stock awarded under the 1993 Omnibus Stock Incentive Plan. For a more detailed description of the terms of the restricted stock, see the Compensation Discussion and Analysis.

(5) Consists of non-qualified stock options to purchase shares of WEC Energy Group common stock pursuant to the 1993 Omnibus Stock Incentive Plan. For a more detailed description of the terms of the options, see the Compensation Discussion and Analysis.

(6) The exercise price of the option awards is equal to the fair market value of WEC Energy Group's common stock on the date of grant. Fair market value is the average of the high and low prices of WEC Energy Group common stock, which is listed on the New York Stock Exchange, reported by Bloomberg, LLP on the grant date.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END 2018

The following table reflects the number and value of exercisable and unexercisable options as well as the number and value of other equity awards held by the NEOs at fiscal year-end 2018.

	Option Awards					Stock Awards			
Name	Number of Securities Underlying Unexercised Options: Exercisable (#)	Number of Securities Underlying Unexercised Options: Unexercisable [1] (#)	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock that Have Not Vested [2] (#)	Market Value of Shares or Units of Stock that Have Not Vested ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights that Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights that Have Not Vested [3] ($)
Gale E. Klappa	180,310	—	—	37.46	1/2/23	—	—	—	—
	302,535	—	—	41.025	1/2/24	—	—	—	—
	176,010	—	—	52.895	1/2/25	—	—	—	—
	190,830	—	—	50.925	1/4/26	—	—	—	—
	—	115,960	—	66.015	1/2/28	—	—	—	—
	—	—	—	—	—	59,866	4,146,319	—	—
Scott J. Lauber	3,650	—	—	34.875	1/3/22	—	—	—	—
	6,360	—	—	37.46	1/2/23	—	—	—	—
	9,560	—	—	41.025	1/2/24	—	—	—	—
	5,330	—	—	52.895	1/2/25	—	—	—	—
	—	6,720	—	50.925	1/4/26	—	—	—	—
	—	17,320	—	58.305	1/3/27	—	—	—	—
	—	26,465	—	66.015	1/2/28	—	—	—	—
	—	—	—	—	—	3,780	261,803	—	—
	—	—	—	—	—	—	—	14,202	983,631
	—	—	—	—	—	—	—	19,497	1,350,362
J. Kevin Fletcher	12,845	—	—	52.895	1/2/25	—	—	—	—
	—	14,260	—	50.925	1/4/26	—	—	—	—
	—	17,345	—	58.305	1/3/27	—	—	—	—
	—	16,055	—	66.015	1/2/28	—	—	—	—
	—	—	—	—	—	3,040	210,550	—	—
	—	—	—	—	—	—	—	14,222	985,016
	—	—	—	—	—	—	—	11,832	819,484
Frederick D. Kuester	—	50,055	—	59.99	3/1/28	—	—	—	—
	—	—	—	—	—	24,609	1,704,419	—	—
Margaret C. Kelsey	—	18,380	—	66.015	1/2/28	—	—	—	—
	—	—	—	—	—	1,695	117,396	—	—
	—	—	—	—	—	—	—	13,539	937,711
Allen L. Leverett	112,250	—	—	34.875	1/3/22	—	—	—	—
	197,360	—	—	37.46	1/2/23	—	—	—	—
	134,055	—	—	41.025	1/2/24	—	—	—	—
	77,955	—	—	52.895	1/2/25	—	—	—	—
	—	82,455	—	50.925	1/4/26	—	—	—	—
	—	42,679	—	58.325	5/2/26	—	—	—	—
	—	130,640	—	58.305	1/3/27	—	—	—	—
	—	120,925	—	66.015	1/2/28	—	—	—	—
	—	—	—	—	—	23,248	1,610,156	—	—
	—	—	—	—	—	—	—	107,114	7,418,716
	—	—	—	—	—	—	—	89,103	6,171,274
J. Patrick Keyes	10,460	—	—	34.875	1/3/22	—	—	—	—
	95,265	—	—	37.46	1/2/23	—	—	—	—
	57,335	—	—	41.025	1/2/24	—	—	—	—
	32,685	—	—	52.895	1/2/25	—	—	—	—
	—	37,665	—	50.925	1/4/26	—	—	—	—
	—	29,800	—	58.305	1/3/27	—	—	—	—
	—	24,825	—	66.015	1/2/28	—	—	—	—
	—	—	—	—	—	5,353	370,749	—	—
	—	—	—	—	—	—	—	24,433	1,692,230
	—	—	—	—	—	—	—	18,290	1,266,765

(1) All options reported in this column were granted ten years prior to their respective expiration date and vest 100% on the third anniversary of the grant date. Upon his separation from the Company effective January 4, 2019, Mr. Keyes forfeited the 29,800 and 24,825 options that expire on January 3, 2027 and January 2, 2028, respectively.

(2) Effective January 4, 2016, Messrs. Lauber, Fletcher, Leverett, and Keyes were granted restricted stock awards of 585; 1,239; 7,173; and 3,276 shares, respectively, which began vesting in three equal annual installments on January 4, 2017. Effective May 2, 2016, Mr. Leverett was granted a restricted stock award of 3,186 shares, which began vesting in three equal annual installments on May 2, 2017. Effective May 2, 2016, Mr. Klappa was granted a restricted stock award of 2,858 shares for his service as Non-Executive Chairman of the Company's Board of Directors, which will vest 100% on May 2, 2019. Effective January 3, 2017, Messrs. Lauber, Fletcher, Leverett, and Keyes were granted restricted stock awards of 1,719; 1,722; 12,975; and 2,958 shares, respectively, which began vesting in three equal annual installments on January 3, 2018. Effective January 2, 2018, Messrs. Lauber, Fletcher, Leverett, and Keyes, and Ms. Kelsey, were granted restricted stock awards of 2,439; 1,479; 11,145; 2,289; and 1,695 shares, respectively, which began vesting in three equal annual installments on January 2, 2019. Effective January 2, 2018, Mr. Klappa was granted a restricted stock award of 57,008 shares, which vested 100% on January 2, 2019. Effective March 1, 2018, Mr. Kuester was granted a restricted stock award of 24,609 shares which vested 100% on March 1, 2019. The vesting of the restricted stock granted to Messrs. Lauber, Fletcher, and Keyes, and Ms. Kelsey, may be accelerated in connection with a termination of employment due to a change in control, death or disability, or by action of the Compensation Committee. Upon his separation from the Company effective January 4, 2019, Mr. Keyes forfeited all unvested shares of restricted stock.

(3) The number of performance units reported were awarded in 2017 (first line) and 2018 (second line) and vest at the end of the three-year performance period ending December 31, 2019 and December 31, 2020, respectively. The number of performance units reported and their corresponding value are based upon a payout at the maximum amount for both 2017 and 2018. The number and value of the 2017 performance units includes performance units resulting from the grant of short-term dividend equivalents and Achievement of the Additional Performance Measure in 2017 and 2018. The number and value of the 2018 performance units includes performance units resulting from the grant of short-term dividend equivalents and achievement of the Additional Performance Measure in 2018.

OPTION EXERCISES AND STOCK VESTED FOR FISCAL YEAR 2018

This table shows the number and value of (1) stock options that were exercised by the NEOs, (2) restricted stock awards that vested, and (3) performance units that vested in 2018.

	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise (#)	Value Realized on Exercise [1] ($)	Number of Shares Acquired on Vesting [2] (#)	Value Realized on Vesting [3][4] ($)
Gale E. Klappa	246,618	8,560,938	4,429	281,668
	—	—	—	—
Scott J. Lauber	—	—	923	60,640
	—	—	3,763	260,624
J. Kevin Fletcher	72,455	2,378,464	1,360	89,371
	—	—	7,979	552,604
Frederick D. Kuester	168,790	5,725,198	—	—
	—	—	—	—
Margaret C. Kelsey	—	—	—	—
	—	—	—	—
Allen L. Leverett	—	—	8,984	590,383
	—	—	66,457	4,602,790
J. Patrick Keyes	—	—	3,029	199,052
	—	—	21,079	1,459,903

(1) Value realized upon the exercise of options is determined by multiplying the number of shares received upon exercise by the difference between the market price of WEC Energy Group common stock at the time of exercise and the exercise price.

(2) Reflects the number of shares of restricted stock that vested in 2018 (first line) and, the number of performance units that vested as of December 31, 2018, the end of the applicable three-year performance period (second line). The performance units were settled in cash.

(3) Restricted stock value realized is determined by multiplying the number of shares of restricted stock that vested by the fair market value of WEC Energy Group common stock on the date of vesting. We compute fair market value as the average of the high and low prices of WEC Energy Group common stock reported by Bloomberg, LLP on the vesting date.

(4) Performance units value realized is determined by multiplying the number of performance units that vested by the closing market price of WEC Energy Group common stock on December 31, 2018, the last trading day of the year.

PENSION BENEFITS AT FISCAL YEAR-END 2018

The following table sets forth information for each NEO regarding their pension benefits at fiscal year-end 2018 under WEC Energy Group's three different retirement plans discussed below.

Name	Plan Name	Number of Years Credited Service [1] (#)	Present Value of Accumulated Benefit [5][6] ($)	Payments During Last Fiscal Year[7] ($)
Gale E. Klappa[2]	WEC Energy Group Plan	13	274,933	—
	SERP	—	3,269,974	263,731
	Individual Letter Agreement	38.67	22,933,487	1,849,639
Scott J. Lauber	WEC Energy Group Plan	28.5	505,856	—
	SERP	28.5	165,017	—
	Individual Letter Agreement	—	—	—
J. Kevin Fletcher	WEC Energy Group Plan	7.17	139,950	—
	SERP	7.17	289,379	—
	Individual Letter Agreement	41.75	5,347,216	—
Frederick D. Kuester[3]	WEC Energy Group Plan	—	—	—
	SERP	9.17	864,942	61,739
	Individual Letter Agreement	40.33	9,271,352	661,782
Margaret C. Kelsey[4]	WEC Energy Group Plan	—	—	—
	SERP	—	—	—
	Individual Letter Agreement	—	—	—
Allen L. Leverett	WEC Energy Group Plan	15.5	340,716	—
	SERP	15.5	2,340,189	—
	Individual Letter Agreement	30	14,539,604	—
J. Patrick Keyes	WEC Energy Group Plan	7.67	148,788	—
	SERP	7.67	447,936	—
	Individual Letter Agreement	7.67	151,334	—

(1) Years of service are computed as of December 31, 2018, the pension plan measurement date used for financial statement reporting purposes. Messrs. Fletcher and Leverett have been credited with 34.58 and 14.5 years of service, respectively, pursuant to the terms of their Individual Letter Agreements ("ILAs"). Prior to his retirement in May 2016, Mr. Klappa was credited with 25.67 years of service pursuant to the terms of his ILA. Prior to his retirement in January 2013, Mr. Kuester was credited with 31.16 years of service pursuant to the terms of his ILA. The increase in the aggregate amount of each of Messrs. Klappa's, Fletcher's, Kuester's, and Leverett's accumulated benefit under all of WEC Energy Group's retirement plans resulting from the additional years of credited service is $20,981,171, $4,460,712, $8,192,804, and $10,536,282, respectively.

(2) Upon his retirement in May 2016, Mr. Klappa's ILA terminated. At that time, the number of years of credited service and the accumulated benefit effectively transferred to the WEC Energy Group Plan and the SERP. Payments related to the ILA were actually paid under the WEC SERP. Mr. Klappa is not accruing additional benefits under these plans in connection with his current service.

(3) Upon his retirement in January 2013, Mr. Kuester's ILA terminated. At that time, the number of years of credited service and the accumulated benefit effectively transferred to the WEC Energy Group Plan and the SERP. Payments related to the ILA were actually paid under the WEC SERP. Mr. Kuester is not accruing additional benefits under these plans in connection with his current service.

(4) Ms. Kelsey is not eligible to receive pension benefits under the WEC Energy Group Plan.

(5) The key assumptions used in calculating the actuarial present values reflected in this column are:

- Earliest projected unreduced retirement age based upon projected service:
  - For Mr. Klappa, age 65.67 (actual age at retirement).
  - For Mr. Lauber, age 60.
  - For Mr. Fletcher, age 65.
  - For Mr. Kuester, age 62.42 (actual age at retirement).
  - For Mr. Leverett, age 60.
  - For Mr. Keyes, age 55.58.
- Discount rate of 4.30%.
- Cash balance interest crediting rate of 5.00%.
- Form of payment:
  - Mr. Klappa's actual form of payment elected at retirement: WEC Energy Group Plan, SERP, and ILA - Single Life annuity
  - Mr. Lauber: WEC Energy Group Plan 50% lump sum / 50% life annuity; SERP - Life annuity
  - Messrs. Fletcher and Keyes: WEC Energy Group Plan 50% lump sum / 50% life annuity; SERP and ILA - Life annuity.
  - Mr. Kuester"s actual form of payment elected at retirement: WEC Energy Group Plan - Lump Sum; SERP and ILA - 50% Joint & Survivor annuity
  - Mr. Leverett: WEC Energy Group Plan 50% lump sum / 50% life annuity; SERP and ILA - 5 annual installments.
- Mortality Table, for Messrs. Klappa's, Lauber's, Fletcher's, Kuester's life annuity, and Leverett's actuarial 5 annual installments - RP2014/ Male/White Collar with modified MP2017 projection.

(6) WEC Energy Group's pension benefit obligations to Messrs. Klappa, Fletcher, Kuester, and Leverett will be partially offset by pension benefits they are entitled to receive from their former employers. The amounts reported for Messrs. Klappa, Fletcher, Kuester, and Leverett, represent only WEC Energy Group's obligation of the aggregate actuarial present value of each of their accumulated benefit under all of the plans. The total aggregate actuarial present value of each of Messrs. Klappa's, Fletcher's, Kuester's, and Leverett's accumulated benefit under all of the plans is $31,010,886, $8,054,982, $13,374,898, and $17,861,925, respectively, $4,532,492, $2,278,437, $3,238,604, and $641,416 of which we estimate the prior employer is obligated to pay. If Messrs. Klappa, Fletcher, Kuester, and Leverett's former employer becomes unable to pay its portion of his respective accumulated pension benefit, WEC Energy Group may be obligated to pay the total amount.

(7) Messrs. Klappa and Kuester continued to receive retirement benefits under the SERP; however, payments under the WEC Energy Group Plan were suspended for Mr. Klappa at the time he resumed his role as an executive officer with the Company. Mr. Kuester's entire WEC Energy Group Plan balance was previously paid in the form of a lump sum; therefore no further benefit exists for him in this plan.

RETIREMENT PLANS

WEC Energy Group maintains four different plans providing for retirement payments and benefits for the NEOs: a defined benefit pension plan of the cash balance type ("WEC Energy Group Plan"); a supplemental executive retirement plan ("SERP"); ILAs; and the WEC Energy Group Retirement Savings Plan, which is a 401(k) plan. The compensation currently considered for purposes of the retirement plans (other than the WEC Energy Group Plan and SERP) for Messrs. Fletcher and Leverett is $1,022,337 and $3,177,680, respectively. These amounts represent the average compensation (consisting of base salary and annual incentive compensation) for the 36 highest consecutive months. For Messrs. Lauber and Keyes, the compensation considered for purposes of the retirement plans (other than the WEC Energy Group Plan) is $1,334,961 and $1,439,693, respectively. These amounts represent their 2018 base salary, plus their 2017 STPP award paid in 2018. As of December 31, 2018, Messrs. Lauber, Fletcher, Leverett, and Keyes currently have or are considered to have 28.5, 41.75, 30, and 7.67 credited years of service, respectively, under the various plans described below. Messrs. Lauber and Keyes were not granted additional years of credited service.

See below for a discussion of the contributions made to the WEC Energy Group Retirement Savings Plan on behalf of Messrs. Klappa and Kuester, and Ms. Kelsey, who do not participate in the WEC Energy Group Plan.

The WEC Energy Group Plan

Most regular full-time and part-time employees, including several of the NEOs, participate in the WEC Energy Group Plan. The WEC Energy Group Plan bases a participant's defined benefit pension on the value of a hypothetical account balance. For individuals participating in the WEC Energy Group Plan as of December 31, 1995, a starting account balance was created equal to the present value of the benefit accrued as of December 31, 1994, under the plan benefit formula prior to the change to a cash balance approach. That formula provided a retirement income based on years of credited service and average compensation (consisting of base salary and annual incentive compensation) for the 36 highest consecutive months, with an adjustment to reflect the Social Security integrated benefit. In addition, individuals participating in the WEC Energy Group Plan as of December 31, 1995, received a special one-time transition credit amount equal to a specified percentage varying with age multiplied by credited service and 1994 base pay.

The present value of the accrued benefit as of December 31, 1994, plus the transition credit, was also credited with interest at a stated rate. For 1996 through 2007, a participant received annual credits to the account equal to 5% of base pay (including WEC Energy Group 401(k) plan pre-tax deferrals and other items), plus an interest credit on all prior accruals equal to 4% plus 75% of the annual time-weighted trust investment return for the year in excess of 4%. From 2008 through 2013, the interest credit percentage was set at either the long-term corporate bond third segment rate, published by the Internal Revenue Service, or 4%, whichever was greater.

Effective January 1, 2014, participants receive an annual credit to the account equal to 6% of base pay (including WEC Energy Group 401(k) plan pre-tax deferrals and other items), plus an interest credit on all prior accruals equal to a 5% fixed rate. For participants in the WEC Energy Group Plan on December 31, 2007 and December 31, 2013, their WEC Energy Group Plan benefit will never be less than the benefit accrued as of December 31, 2007 and December 31, 2013, respectively. The WEC Energy Group Plan benefit will be calculated under all three formulas to provide participants with the greater benefit; however, in calculating a participant's benefit accrued as of December 31, 2007 and December 31, 2013, interest credits as defined under each of the prior WEC Energy Group Plan formulas will be taken into account but not any additional pay credits.

Participants who were "grandfathered" as of December 31, 1995, as discussed below, will still receive the greater of the grandfathered benefit or the cash balance benefit.

The life annuity payable under the WEC Energy Group Plan is determined by converting the hypothetical account balance credits into annuity form.

Individuals who were participants in the WEC Energy Group Plan on December 31, 1995 were "grandfathered" so that they will not receive any lower retirement benefit than would have been provided under the formula in effect through December 31, 1995, had it continued. This amount continued to increase until December 31, 2010, at which time it was frozen. Upon retirement,

participants will receive the greater of this frozen amount or the accumulated cash balance.

For Mr. Lauber, estimated benefits under the grandfathered formula are higher than under the cash balance plan formula. Messrs. Fletcher, Leverett, and Keyes do not participate in the grandfathered formula. Although all of the NEOs (other than Mr. Kuester and Ms. Kelsey) participate in the cash balance plan formula, pursuant to the agreement discussed below, Mr. Leverett's total retirement benefits would be determined by the prior plan benefit formula if he were to retire at or after age 60. Mr. Leverett's agreement also provides that the prior plan benefit formula will continue to be applied until retirement, with no amounts frozen as of December 31, 2010. Mr. Leverett would receive the cash balance in his account if he was to terminate employment prior to attaining the age of 60. Although Mr. Leverett resigned as President of WEC Energy Group effective October 10, 2018, he remains an inactive employee, which is consistent with the Company's policy regarding similarly-situated management employees. Therefore, Mr. Leverett remains entitled to these retirement benefits.

Under the WEC Energy Group Plan, participants receive unreduced pension benefits upon reaching one of the following three thresholds: (1) age 65; (2) age 62 with 30 years of service; or (3) age 60 with 35 years of service.

Pursuant to the Internal Revenue Code, only $275,000 of pension eligible earnings (base pay and annual incentive compensation) may be considered for purposes of the WEC Energy Group Plan.

Supplemental Executive Retirement Plans and Individual Letter Agreements

Designated officers of WEC Energy Group, including all of the NEOs (other than Ms. Kelsey) participate in the SERP, which is part of the Supplemental Pension Plan (the "SPP") adopted to comply with Section 409A of the Internal Revenue Code. The SERP provides monthly supplemental pension benefits to participants, which will be paid out of unsecured corporate assets, or the grantor trust described below, in an amount equal to the difference between the actual pension benefit payable under the WEC Energy Group Plan and what such pension benefit would be if calculated without regard to any limitation imposed by the Internal Revenue Code on pension benefits or covered compensation, including amounts deferred to the WEC Energy Group Executive Deferred Compensation Plan. Except for a "change in control" of WEC Energy Group, as defined in the SPP, and pursuant to the terms of the ILAs discussed below, no payments are made until after the participant's retirement at or after age 60 or death. If a participant in the SERP dies prior to age 60, his or her beneficiary is entitled to receive retirement benefits under the SERP. Although Messrs. Klappa and Kuester remain participants in the SPP, they no longer accrue any benefits under the plan as a result of their earlier retirements. In addition, although Mr. Keyes remains a participant in the SPP, he no longer accrues any benefits under the plan as a result of his separation from the Company.

WEC Energy Group entered into an individual letter agreement with Mr. Klappa when he first commenced employment in 2003 to provide him with supplemental retirement benefits upon retirement at or after age 60. The supplemental retirement payments are intended to make the total retirement benefits payable to Mr. Klappa comparable to that which would have been received under the WEC Energy Group Plan as in effect on December 31, 1995, had the defined benefit formula then in effect continued until his retirement, calculated without regard to Internal Revenue Code limits, and as if Mr. Klappa had started participation in the WEC Energy Group Plan. Pursuant to the terms of the agreement, which terminated upon Mr. Klappa's retirement in May 2016, Mr. Klappa's benefits under the WEC Energy Group Plan and the SERP are being paid under the prior plan benefit formula as in effect on December 1, 1995, and as if Mr. Klappa had started with WEC Energy Group at age 27. As a result, Mr. Klappa had 38.67 years of credited service under the WEC Energy Group Plan and the SERP upon his retirement in May 2016.

WEC Energy Group entered into an agreement with Mr. Fletcher to provide him with supplemental retirement benefits upon his retirement, provided he completed one year of service with the Company. The supplemental retirement payments are intended to make the total retirement benefits payable to Mr. Fletcher comparable to that which would have been received under his prior employer's defined benefit pension plan, calculated without regard to Internal Revenue Code limits, and as if Mr. Fletcher's employment continued with the prior employer and the defined benefit formula then in effect under the prior employer's plan continued to his retirement. The retirement benefits payable as a result of this agreement will be offset by the value of any qualified and non-qualified defined benefit pension plan of the prior employer.

WEC entered into an individual letter agreement with Mr. Kuester when he first commenced employment in 2003 that was similar to Mr. Klappa's agreement to provide him with supplemental retirement benefits upon retirement at or after age 60. Pursuant to the terms of the agreement, which terminated upon Mr. Kuester's retirement in January 2013, Mr. Kuester's benefits under the WEC Energy Group Plan and the SERP are being paid under the prior plan benefit formula as in effect on December 1, 1995, and as if Mr. Kuester had started with WEC Energy Group at age 22. As a result, Mr. Kuester had 40.33 years of credited service under the WEC Energy Group Plan and the SERP upon his retirement in January 2013.

WEC Energy Group entered into an agreement with Mr. Leverett that was similar to Mr. Klappa's agreement to provide him with supplemental retirement benefits upon retirement at or after age 60. The supplemental retirement payments are intended to make the total retirement benefits payable to Mr. Leverett comparable to that which would have been received under the WEC Energy Group Plan as in effect on December 31, 1995, had the defined benefit formula then in effect continued until his retirement, calculated without regard to Internal Revenue Code limits, and as if Mr. Leverett had started participation in the WEC

Energy Group Plan on January 1, 1989. The retirement benefits payable to Mr. Leverett will be offset by the value of any qualified or non-qualified defined benefit pension plans of prior employers.

Mr. Leverett's agreement also provides for a pre-retirement spousal benefit to be paid to his spouse in the event of his death while employed by the Company. The benefit payable is equal to the amount which would have been received by Mr. Leverett's spouse under the WEC Energy Group Plan as in effect on December 31, 1995, had the benefit formula then in effect continued until Mr. Leverett's death, calculated without regard to Internal Revenue Code limits, and as if Mr. Leverett had started at the age indicated above. The spousal benefit payable would be offset by one half of the value of any qualified or non-qualified deferred benefit pension plans of Mr. Leverett's prior employer.

WEC Energy Group entered into an agreement with Mr. Keyes when he was hired as Vice President and Treasurer in 2011 that provided for a supplemental pension benefit account, which was credited with $100,000. This account was credited with interest annually at the same rate as the WEC Energy Group Plan. The account balance would have vested at the earliest to occur of Mr. Keyes attaining age 60 or completion of 10 years of service; however, Mr. Keyes forfeited this benefit upon his separation from the Company.

The purpose of these agreements was to ensure that Messrs. Klappa, Fletcher, Leverett, and Keyes did not lose pension earnings by joining the executive management team at WEC Energy Group they otherwise would have received from their former employers. Without providing a means to retain these pension benefits, it would have been difficult for WEC Energy Group to attract these officers.

The SPP provides for a mandatory lump sum payment upon a change in control if the executive's employment is terminated within 18 months after the change in control. The Wisconsin Energy Corporation 2014 Rabbi Trust, a grantor trust, funds certain non-qualified benefits, including the SPP and the ILAs, as well as the Executive Deferred Compensation Plan and the Directors' Deferred Compensation Plan. See "Potential Payments upon Termination or Change in Control" later in this proxy statement for additional information.

WEC Energy Group Retirement Savings Plan

Effective January 1, 2015, all newly hired management employees, including executive officers, will receive an annual contribution equal to 6% of pension eligible wages from the Company into WEC Energy Group's 401(k) plan rather than participate in the WEC Energy Group Plan. Pension eligible wages consist of annual base salary and STPP payouts. In connection with this plan, the Compensation Committee adopted the WEC Energy Group Non-Qualified Retirement Savings Plan which provides "make-whole" benefits to address Internal Revenue Code limits on the amount of money that can be contributed to a 401(k) plan.

Since Messrs. Klappa and Kuester are considered new employees, they will no longer accrue additional benefits under the WEC Energy Group Plan; however, Messrs. Klappa and Kuester, along with Ms. Kelsey, are entitled to receive Company contributions to the 401(k) plan and Non-Qualified Retirement Savings Plan.

NONQUALIFIED DEFERRED COMPENSATION FOR FISCAL YEAR 2018

The following table reflects activity by the NEOs during 2018 in WEC Energy Group's Executive Deferred Compensation Plan discussed below.

Name	Executive Contributions in Last Fiscal Year [1] ($)	Registrant Contributions in Last Fiscal Year [1] ($)	Aggregate Earnings In Last Fiscal Year ($)	Aggregate Withdrawals / Distributions ($)	Aggregate Balance at Last Fiscal Year-End [2] ($)
Gale E. Klappa	84,404	46,000	353,452	947,996	6,722,197
Scott J. Lauber	189,344	42,239	58,628	—	1,693,064
J. Kevin Fletcher	531,410	33,700	125,979	—	2,803,514
Frederick D. Kuester	—	—	66,379	285,333	1,141,332
Margaret C. Kelsey	36,010	16,914	16,082	—	222,326
Allen L. Leverett	441,304	143,089	52,008	—	6,291,763
J. Patrick Keyes	921,638	46,557	(263,131)	—	5,897,325

(1) All of the amounts are reported as compensation in the "Summary Compensation Table" of this proxy statement.

(2) $227,270, $693,245, $3,556,960, and $2,678,095 of the reported amounts were reported as compensation in the Summary Compensation Tables in prior proxy statements for Messrs. Lauber, Fletcher, Leverett, and Keyes, respectively. Messrs. Klappa and Kuester reported $6,931,246 and $2,350,309, respectively, in the Summary Compensation Tables in prior proxy statements. The amounts reported in this column for Messrs. Klappa and Kuester are lower than these previously reported amounts because Messrs. Klappa and Kuester have been receiving distributions

under the WEC Energy Group Executive Deferred Compensation Plan. Ms. Kelsey became a named executive officer in 2018; therefore, no amounts were previously reported in prior proxy statements for her. The amount for Ms. Kelsey includes a $150,000 contribution from WEC Energy Group in 2017 that vests upon Ms. Kelsey's third anniversary with the Company.

Executive Deferred Compensation Plan

WEC Energy Group maintains two executive deferred compensation plans in which the NEOs participate: the Legacy WEC Energy Group Executive Deferred Compensation Plan (the "Legacy EDCP"), and the WEC Energy Group Executive Deferred Compensation Plan (the "EDCP") adopted effective January 1, 2005 to comply with Section 409A of the Internal Revenue Code. The Legacy EDCP provides that (1) amounts earned, deferred, vested, credited, and/or accrued as of December 31, 2004 are preserved and frozen so that these amounts are exempt from Section 409A and (2) no new employees may participate in the Legacy EDCP as of January 1, 2005. Since January 1, 2005, all deferrals have been made to the EDCP. The provisions of the EDCP as in effect on December 31, 2018 are described below, as are the payout provisions of the Legacy EDCP.

The EDCP. Under the plan, a participant may defer up to 50% of his or her base salary, annual incentive compensation and vested awards of performance units. Stock option gains and vested restricted stock may not be deferred into the EDCP. Generally, deferral elections are made annually by each participant for the upcoming plan year. The Company maintains detailed records tracking each participant's "account balance." In addition to deferrals made by the participants, the Company may also credit each participant's account balance by matching a certain portion of each participant's deferral. Such deferral matching is determined by a formula taking into account the matching rate applicable under the Company's 401(k) plan, the percentage of compensation subject to such matching rate, the participant's gross compensation eligible for matching, and the amount of eligible compensation actually deferred. Also, in our discretion, the Company may credit any other amounts, as appropriate, to each participant's account.

Mr. Kuester was not eligible to defer any compensation into the EDCP for 2018, nor was he eligible for any Company contributions to the EDCP.

Participants may elect to participate in the Company's stock measurement fund and/or the Prime Rate Fund. The Company tracks each participant's account balance as though the balance was actually invested in these funds. Fund elections are not actual investments, but are elections chosen only for purposes of calculating market gain or loss on deferred amounts for the duration of the deferral period. Each participant may select the amount of deferred compensation to be allocated among the two measurement funds. Contributions and deductions may be made to each participant's account based on the performance of the measurement fund(s) elected.

The annual rate of return for the calendar year ended December 31, 2018 for the WEC Energy Group Common Stock Fund and the Prime Rate Fund was 4.3% and 4.88%, respectively.

Each participant's account balance is debited or credited periodically based on the performance of the measurement fund(s) elected by the participant. Subject to certain restrictions, participants may make changes to their measurement fund elections by notice to the committee administering the plan.

At the time of his or her deferral election, each participant may designate a prospective payout election for any or the entire amount deferred, plus any amounts debited or credited to the deferred amount as of the designated payout. Amounts deferred into the EDCP may not be withdrawn at the discretion of the participant and a change to the designated payout delays the initial payment at least five years beyond the originally designated payout date. In addition, the Company may not limit payout amounts in order to deduct such amounts under Section 162(m) of the Internal Revenue Code.

The balance of a participant's account is payable on his or her retirement in either a lump sum payout or in annual installments, at the election of the participant. Upon the death of a participant after retirement, payouts are made to the deceased participant's beneficiary in the same manner as though such payout would have been made to the participant had the participant survived. In the event of a participant's termination of employment prior to retirement, the participant may elect to receive a payout beginning the year after termination in the amount of his or her account balance as of the termination date either in a lump sum or in annual installments over a period of five years. Disability is not itself a payment event until the participant terminates employment with WEC Energy Group or its subsidiaries. A participant's account balance will be paid out in a lump sum if the participant separates from service with WEC Energy Group or its subsidiaries within 18 months after a change in control of WEC Energy Group, as defined in the plan. The deferred amounts will be paid out of the general corporate assets or the assets of the Wisconsin Energy Corporation 2014 Rabbi Trust.

The Legacy EDCP. At the time of his or her deferral election, each participant designated a prospective payout election for any or the entire amount deferred, plus any amounts debited or credited to the deferred amount as of the designated payout. A participant may elect, at any time, to withdraw part (a minimum of $25,000) or all of his or her account balance, subject to a withdrawal penalty of 10%. Payout amounts may be limited to the extent to which they are deductible by the Company under Section 162(m) of the Internal Revenue Code.

The balance of a participant's account is payable on his or her retirement in either a lump sum payout or in annual installments, at the election of the participant. Upon the death of a participant after retirement, payouts are made to the deceased participant's beneficiary in the same manner as though such payout would have been made to the participant had the participant survived. In the event of a participant's termination of employment prior to retirement, the participant may elect to receive a payout beginning the year after termination in the amount of his or her account balance as of the termination date either in a lump sum or in annual installments over a period of five years. Any participant who suffers from a continued disability will be entitled to the benefits of plan participation unless and until the committee administering the plan determines that the participant has been terminated for purposes of continued participation in the plan. Upon any such determination, the disabled participant is paid out as though the participant had retired. Except in certain limited circumstances, participants' account balances will be paid out in a lump sum (1) upon the occurrence of a change in control, as defined in the plan, or (2) upon any downgrade of the Company's senior debt obligations to less than "investment grade." The deferred amounts will be paid out of the general corporate assets or the assets of the Wisconsin Energy Corporation 2014 Rabbi Trust.

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE IN CONTROL

The tables below reflect the amount of compensation payable to each of our NEOs (other than Mr. Keyes) in the event of termination of each executive's employment. These amounts are in addition to each NEO's aggregate balance in the EDCP at fiscal year-end 2018, as reported in the "Aggregate Balance at Last Fiscal Year-End" column under "Nonqualified Deferred Compensation for Fiscal Year 2018." The amount of compensation payable to each NEO (other than Mr. Keyes) upon voluntary termination, normal retirement, for-cause termination, involuntary termination (by the Company for any reason other than cause, death or disability or by the executive for "good reason"), termination following a "change in control," disability, and death are set forth below. The amounts shown assume that such termination was effective as of December 31, 2018 and include amounts earned through that date, and are estimates of the amounts which would be paid out to the NEOs upon termination. The amounts shown under "Normal Retirement" assume the NEOs were retirement eligible with no reduction of retirement benefits. The amounts shown under "Termination Upon a Change in Control" assume the NEOs terminated employment as of December 31, 2018, which was within 18 months of a change in control of WEC Energy Group. The amounts reported in the row titled "Retirement Plans" in each table below are not in addition to the amounts reflected under "Pension Benefits at Fiscal Year-End 2018." The actual amounts to be paid out can only be determined at the time of an officer's termination of employment.

Payments Made Upon Voluntary Termination or Termination for Cause, Death or Disability

In the event a NEO voluntarily terminates employment or is terminated for cause, death, or disability, the officer will receive:

- accrued but unpaid base salary and, for termination by death or disability, prorated annual incentive compensation;
- 401(k) plan and EDCP account balances;
- the WEC Energy Group Plan cash balance;
- in the case of death or disability, full vesting in all outstanding stock options, restricted stock, and performance units (otherwise, the ability to exercise already vested options within three months of termination) as well as vesting in the SERP and ILAs; and
- if voluntary termination occurs after age 60, such termination is treated as a normal retirement.

NEOs are also entitled to the value of unused vacation days, if any, and for termination by death, benefits payable under the officer life insurance benefit if the NEO participates in such benefit.

On September 6, 2018, Mr. Keyes submitted his resignation from all officer positions with the Company and its subsidiaries, including as Executive Vice President of the Company, effective September 14, 2018. In order to transition his responsibilities to other executives of the Company, he remained an employee until January 4, 2019. In connection with such termination, Mr. Keyes received accrued and unpaid base salary, 401(k) plan and EDCP balances, his WEC Energy Group Plan cash balance, and the value of unused vacation days. As a result, we have not included a table reflecting potential termination payments to Mr. Keyes under other circumstances.

Payments Made Upon Normal Retirement

In the event of the retirement of a NEO, the officer will receive:

- accrued but unpaid base salary and prorated annual incentive compensation;
- full vesting in all outstanding stock options and a prorated amount of performance units;
- full vesting in all retirement plans, including the WEC Energy Group Plan, SERP, and ILAs; and
- 401(k) plan and EDCP account balances.
- NEOs are also entitled to the value of unused vacation days, if any.

Payments Made Under Employment Agreements Upon a Change in Control, Involuntary Termination, or Termination for Good Reason

WEC Energy Group entered into a written employment agreement with Mr. Fletcher effective October 31, 2011. The Compensation Committee did not amend or otherwise modify Mr. Fletcher's employment agreement in any way in connection with his appointment as President and CEO. Pursuant to the terms of this agreement, Mr. Fletcher is entitled to severance benefits if his employment is terminated (1) by the Company for any reason other than cause, death, or disability, or (2) by Mr. Fletcher for good reason. Upon termination, Mr. Fletcher's agreement provides for (1) a lump sum payment equal to 2.99 times his annual base salary for the fiscal year in which termination occurs, and (2) health, life and other welfare benefits (excluding disability benefits) for a period of three years following termination.

Generally, pursuant to Mr. Fletcher's ILA, good reason means:

(1) a material reduction in the executive's base compensation;

(2) a material change in the geographic location at which the executive must perform services; or

(3) a material breach of the agreement by the Company.

WEC Energy Group also entered into a written employment agreement with Mr. Leverett, dated as of December 28, 2008, which provides for certain severance benefits if his employment is terminated, among other ways:

- in anticipation of or following a change in control by the Company for any reason, other than cause, death, or disability;
- by Mr. Leverett for good reason in anticipation of or following a change in control; or
- by Mr. Leverett within six months after completing one year of service following a change in control.

Upon termination of his employment in connection with a change in control, Mr. Leverett's agreement provides for:

- a lump sum severance payment equal to three times the sum of Mr. Leverett's highest annual base salary in effect for the three years preceding his termination and highest bonus amount;
- three years continuation of health and certain other welfare benefit coverage and eligibility for retiree health coverage thereafter;
- a payment equal to the value of three additional years of participation in the applicable qualified and non-qualified retirement plans based upon the higher of (1) the annual base salary in effect at the time of termination, and (2) any salary in effect during the 180 day period preceding termination, plus the highest bonus amount;
- a payment equal to the value of three additional years of Company match in the 401(k) plan and EDCP;
- full vesting in all outstanding stock options, restricted stock, and other equity awards;
- 401(k) and EDCP account balances;
- certain financial planning services and other benefits; and
- a "gross up" payment should any payments under the agreement trigger federal excise taxes under the "parachute payment" provisions of the tax law.

The highest bonus amount would be calculated as the larger of (1) the current target bonus for the fiscal year in which employment termination occurs, or (2) the highest bonus paid in any of the last three fiscal years of the Company prior to termination or the change in control. The agreement contains a one-year non-compete provision applicable on termination of employment.

Generally, pursuant to Mr. Leverett's agreement, a change in control is deemed to occur:

(1) if any person or group acquires WEC Energy Group common stock that constitutes more than 50% of the total fair market value or total voting power of WEC Energy Group;

(2) if any person or group acquires (or has acquired during the 12-month period ending on the date of the most recent acquisition by such person or group) WEC Energy Group common stock that constitutes 30% or more of the total voting power of WEC Energy Group;

(3) if a majority of the members of WEC Energy Group's Board is replaced during any 12-month period by directors whose appointment or election is not endorsed by a majority of WEC Energy Group's Board before the date of appointment or election; or

(4) if any person or group acquires (or has acquired during the 12-month period ending on the date of the most recent acquisition by such person or group) assets from WEC Energy Group that have a total gross fair market value equal to or

more than 40% of the total gross value of all the assets of WEC Energy Group immediately before such acquisition or acquisitions, unless the assets are transferred to:

- an entity that is controlled by the stockholders of the transferring corporation;
- a stockholder of WEC Energy Group in exchange for or with respect to its stock;
- an entity of which WEC Energy Group owns, directly or indirectly, 50% or more of its total value or voting power; or
- a person or group (or an entity of which such person or group owns, directly or indirectly, 50% or more of our total value or voting power) that owns, directly or indirectly, 50% or more of the total value or voting power of WEC Energy Group.

Under the terms of his agreement, effective March 2020, Mr. Leverett will no longer be entitled to these change in control benefits.

The employment agreements Messrs. Klappa and Kuester entered into upon commencement of their employment with WEC Energy Group in 2003 terminated upon their retirements in May 2016 and January 2013, respectively.

Pursuant to the terms of the SPP and ILAs, retirement benefits are paid to the NEOs upon termination of employment within 18 months of a change in control. Participants appointed by the Company, including the NEOs, are also eligible to receive a supplemental disability benefit pursuant to the terms of the WEC Energy Group Supplemental Long Term Disability Plan, in an amount equal to the difference between the actual amount of the benefit payable under the long term disability plan applicable to all employees and what such disability benefit would have been if calculated without regard to any limitation imposed by the broad-based plan on annual compensation recognized thereunder. Mr. Leverett is currently receiving benefits under this plan.

Payments under the Severance Pay Plan

Messrs. Klappa, Lauber, and Kuester, and Ms. Kelsey, have not entered into any agreement that currently provides for severance benefits upon a change in control or otherwise. These officers are eligible to participate in the Company's Severance Pay Plan, in which all management employees are eligible to participate. In the event a participant is involuntarily terminated, other than for cause, death, disability, retirement, or resignation, the participant is entitled to receive severance pay in an amount equal to the sum of: (1) 4% of the participant's annual base salary and target bonus, plus (2) 4% of the participant's annual base salary and target bonus multiplied by his or her completed years of service with the Company. The maximum amount of severance pay that can be received under the plan is twelve months of a participant's annual base salary and target bonus.

Potential Payments to Named Executive Officers Upon Termination or Change in Control of the Company

The following tables show the potential payments upon termination or a change in control of the Company for:

Executive Benefits and Payments Upon Separation	Voluntary Termination ($)	Normal Retirement ($)	For Cause Termination ($)	Involuntary Termination ($)	Termination Upon Change in Control ($)	Disability ($)	Death ($)
Gale E. Klappa							
Cash Severance	—	—	—	1,881,000	1,881,000	—	—
Additional Pension Credited Service	—	—	—	—	—	—	—
Additional 401(k) and EDCP Match	—	—	—	—	—	—	—
Long-Term Incentive Compensation:							
Performance Units	—	—	—	—	—	—	—
Restricted Stock	—	—	—	—	3,948,374	3,948,374	3,948,374
Options	—	376,290	—	—	376,290	376,290	376,290
Benefits & Perquisites:							
Retirement Plans	26,478,394	26,478,394	26,478,394	26,478,394	26,478,394	26,478,394	
Health and Welfare Benefits	—	—	—	9,497	9,497	—	—
Excise Tax Gross-Up	—	—	—	—	—	—	—
Financial Planning	—	—	—	—	—	—	—
Outplacement	—	—	—	—	—	—	—
Death Benefit	—	—	—	—	—	—	—
Total	26,478,394	26,854,684	26,478,394	28,368,891	32,693,555	30,803,058	4,324,664
Scott J. Lauber							
Cash Severance	—	—	—	1,059,920	1,059,920	—	—
Additional Pension Credited Service	—	—	—	—	—	—	—
Additional 401(k) and EDCP Match	—	—	—	—	—	—	—
Long-Term Incentive Compensation:							
Performance Units	—	620,085	—	—	1,308,806	1,308,806	1,308,806
Restricted Stock	—	—	—	—	261,803	261,803	261,803
Options	—	398,831	—	—	398,831	398,831	398,831
Benefits & Perquisites:							
Retirement Plans	670,873	670,873	670,873	670,873	670,873	670,873	628,135
Health and Welfare Benefits	—	—	—	9,497	9,497	—	—
Excise Tax Gross-Up	—	—	—	—	—	—	—
Financial Planning	—	—	—	—	—	—	—
Outplacement	—	—	—	—	—	—	—
Death Benefit	—	—	—	—	—	—	—
Total	670,873	1,689,789	670,873	1,740,290	3,709,730	2,640,313	2,597,575
J. Kevin Fletcher							
Cash Severance	—	—	—	2,093,000	2,093,000	—	—
Additional Pension Credited Service	—	—	—	—	—	—	—
Additional 401(k) and EDCP Match	—	—	—	—	—	—	—
Long-Term Incentive Compensation:							
Performance Units	—	521,459	—	—	1,011,889	1,011,889	1,011,889
Restricted Stock	—	—	—	—	210,550	210,550	210,550
Options	—	503,570	—	—	503,570	503,570	503,570
Benefits & Perquisites:							
Retirement Plans	5,776,545	5,776,545	5,776,545	5,776,545	5,776,545	5,776,545	3,465,042
Health and Welfare Benefits	—	—	—	56,984	56,984	—	—
Excise Tax Gross-Up	—	—	—	—	—	—	—
Financial Planning	—	—	—	—	—	—	—
Outplacement	—	—	—	—	—	—	—
Death Benefit	—	—	—	—	—	—	2,100,000
Total	5,776,545	6,801,574	5,776,545	7,926,529	9,652,538	7,502,554	7,291,051

Executive Benefits and Payments Upon Separation	Voluntary Termination ($)	Normal Retirement ($)	For Cause Termination ($)	Involuntary Termination ($)	Termination Upon Change in Control ($)	Disability ($)	Death ($)
Frederick D. Kuester							
Cash Severance	—	—	—	538,965	538,965	—	—
Additional Pension Credited Service	—	—	—	—	—	—	—
Additional 401(k) and EDCP Match	—	—	—	—	—	—	—
Long-Term Incentive Compensation:							
Performance Units	—	—	—	—	—	—	—
Restricted Stock	—	—	—	—	1,704,419	1,704,419	1,704,419
Options	—	162,428	—	—	162,428	162,428	162,428
Benefits & Perquisites:							
Retirement Plans	10,136,294	10,136,294	10,136,294	10,136,294	10,136,294	10,136,294	5,120,424
Health and Welfare Benefits	—	—	—	9,497	9,497	—	—
Excise Tax Gross-Up	—	—	—	—	—	—	—
Financial Planning	—	—	—	—	—	—	—
Outplacement	—	—	—	—	—	—	—
Death Benefit	—	—	—	—	—	—	—
Total	10,136,294	10,298,722	10,136,294	10,684,756	12,551,603	12,003,141	6,987,271
Margaret C. Kelsey							
Cash Severance	—	—	—	70,040	70,040	—	—
Additional Pension Credited Service	—	—	—	—	—	—	—
Additional 401(k) and EDCP Match	—	—	—	—	—	—	—
Long-Term Incentive Compensation:							
Performance Units	—	175,297	—	—	525,822	525,822	525,822
Restricted Stock	—	—	—	—	117,396	117,396	117,396
Options	—	59,643	—	—	59,643	59,643	59,643
Benefits & Perquisites:							
Retirement Plans	—	—	—	—	—	—	—
Health and Welfare Benefits	—	—	—	9,497	9,497	—	—
Excise Tax Gross-Up	—	—	—	—	—	—	—
Financial Planning	—	—	—	—	—	—	—
Outplacement	—	—	—	—	—	—	—
Death Benefit	—	—	—	—	—	—	1,545,000
Total	—	234,940	—	79,537	782,398	702,861	2,247,861
Allen L. Leverett							
Cash Severance	—	—	—	—	12,458,256	—	—
Additional Pension Credited Service	—	—	—	—	6,344,721	—	—
Additional 401(k) and EDCP Match	—	—	—	—	498,330	—	—
Long-Term Incentive Compensation:							
Performance Units	—	3,926,903	—	—	7,620,678	7,620,678	7,620,678
Restricted Stock	—	—	—	—	1,610,156	1,610,156	1,610,156
Options	—	3,802,070	—	—	3,802,070	3,802,070	3,802,070
Benefits & Perquisites:							
Retirement Plans	—	17,220,509	—	—	11,604,163	17,220,509	6,623,909
Health and Welfare Benefits	—	—	—	—	70,485	—	—
Excise Tax Gross-Up	—	—	—	—	16,997,105	—	—
Financial Planning	—	—	—	—	54,000	—	—
Outplacement	—	—	—	—	30,000	—	—
Death Benefit	—	—	—	—	—	—	—
Total	—	24,949,482	—	—	61,089,964	30,253,413	19,656,813

PAY RATIO DISCLOSURE

The primary objective of our executive compensation program is to provide a competitive, performance-based plan that enables the Company to attract and retain key individuals and to reward them for achieving both the Company's short-term and long-term goals without creating an incentive for our NEOs to take excessive risks. In line with this objective, the Company's general pay practice for all management employees is to target the median pay for each individual's position at comparably sized companies.

For 2018, the annual total compensation of Mr. Klappa, our principal executive officer serving in that position on December 31, 2018, of $9,862,993, as shown in the Summary Compensation Table above ("CEO Compensation"), was approximately 91 times the annual total compensation of the median employee of $107,894.

We identified the median employee as of October 7, 2017, using total wages and earnings paid during the rolling 12-month period ended October 7, 2017, as reflected in our internal payroll records (including, without limitation, base salary, wages plus overtime, and annual cash incentive payments, as applicable), for all individuals, excluding Mr. Leverett (then CEO of the Company), who were employed by us or any of our consolidated subsidiaries on October 7, 2017 (whether employed on a full-time, part-time, seasonal or temporary basis and including union and non-union employees). After identifying the median employee, we calculated annual total compensation for such employee using the same methodology we use for our CEO Compensation, which includes annual salary, bonus, change in pension value and 401(k) matching by the Company. As defined under the pay ratio disclosure rules, the median employee remained the same since there has been no change in the Company's employee population or employee compensation that would significantly affect the pay ratio.

To provide further context to our pay practices, due to the complexity of the work associated with operating public utilities, our workforce tends to be more highly skilled than workforces at companies in other industries. Additionally, our employees often work for the Company for long periods of time; our average employee tenure is 15 years.

RISK ANALYSIS OF COMPENSATION POLICIES AND PRACTICES

As part of its process to determine the 2018 compensation of WEC Energy Group's NEOs, the Compensation Committee analyzed whether WEC Energy Group's compensation program taken as a whole creates risks that are reasonably likely to have a material adverse effect on the Company. The Compensation Committee concluded it does not. This analysis applies generally to the compensation program for WEC Energy Group's employees since all management employees (both officers and non-officers) above a certain level are provided with substantially the same mix of compensation as the NEOs. The compensation package provided to employees below this level is not applicable to this analysis as such compensation package does not provide sufficient incentive to take risks that could materially affect the Company.

There is no objective way to measure risk resulting from a corporation's compensation program; therefore, this analysis is subjective in nature. We believe that the only elements of WEC Energy Group's compensation program that could incentivize risk-taking by our employees, and therefore have a reasonable likelihood of materially adversely affecting the Company, are the annual cash incentive compensation and the long-term incentive compensation, the payout of which is dependent upon the achievement of certain performance levels by the Company. Based upon the value of each of these elements to the overall compensation mix and the relative value each has to the other, we believe the Company's compensation program is appropriately balanced. We believe that the mix of short- and long-term awards minimizes risks that may be taken, as any risks taken for short-term gains could ultimately jeopardize the Company's ability to meet the long-term performance objectives. Given the current balance of compensation elements, we do not believe WEC Energy Group's compensation program incentivizes unreasonable risk-taking by management.

The Compensation Committee's stock ownership guidelines require officers who participate in the long-term incentive compensation program to hold an amount of Company common stock and other equity-related Company securities that varies depending upon such officers' level. The guidelines require the Company's executive officers to hold common stock and other equity-related securities of the Company having a minimum fair market value ranging from 250% to 600% of base salary. The Compensation Committee believes these stock ownership guidelines further discourage unreasonable risk taking by Company officers.

As part of this analysis, we also considered the nature of WEC Energy Group's business as a public utility holding company and the fact that substantially all of the Company's earnings and other financial results are generated by, or relate to, regulated public utilities. The highly regulated nature of WEC Energy Group's business, including limits on the amount of profit the Company's public utility subsidiaries (and therefore, WEC Energy Group) may earn, significantly reduces any incentive to engage in conduct that would be reasonably likely to have a material adverse effect on the Company.

PROPOSAL 3: RATIFICATION OF DELOITTE & TOUCHE LLP AS INDEPENDENT AUDITORS FOR 2019

The Audit and Oversight Committee of the Board of Directors has sole authority to select, evaluate, and, where appropriate, terminate and replace the independent auditors. The Audit and Oversight Committee has appointed Deloitte & Touche LLP as the Company's independent auditors for the fiscal year ending December 31, 2019. The Audit and Oversight Committee believes that stockholder ratification of this matter is important considering the critical role the independent auditors play in maintaining the integrity of the Company's financial statements. If stockholders do not ratify the selection of Deloitte & Touche LLP, the Audit and Oversight Committee will reconsider the selection.

Deloitte & Touche LLP has served as the independent auditors for the Company for the last 17 fiscal years beginning with the fiscal year ended December 31, 2002. The members of the Audit and Oversight Committee and the other members of the Board believe that the continued retention of Deloitte & Touche LLP to serve as the Company's independent external auditor is in the best interests of the Company and our stockholders.

Ratification of Deloitte & Touche LLP as the Company's independent auditors requires the affirmative vote of a majority of the votes cast in person or by proxy at the Meeting. Presuming a quorum is present, shares not voted, whether by abstention or otherwise, have no effect on the outcome of this matter.

Representatives of Deloitte & Touche LLP are expected to be present at the Meeting. They will have an opportunity to make a statement if they so desire and are expected to respond to appropriate questions that may be directed to them. Information concerning Deloitte & Touche LLP can be found in the following pages.

The Board of Directors recommends that you vote "FOR" the ratification of Deloitte & Touche LLP as independent auditors for 2019.

INDEPENDENT AUDITORS' FEES AND SERVICES

Pre-Approval Policy. The Audit and Oversight Committee has a formal policy delineating its responsibilities for reviewing and approving, in advance, all audit, audit-related, tax, and other services of the independent auditors. As such, the Audit and Oversight Committee is responsible for the audit fee negotiations associated with the Company's retention of independent auditors.

The Audit and Oversight Committee is committed to ensuring the independence of the auditors, both in appearance as well as in fact. In order to assure continuing auditor independence, the Audit and Oversight Committee periodically considers whether there should be a regular rotation of the independent external audit firm. In addition, the Audit and Oversight Committee is directly involved in the selection of Deloitte & Touche LLP's lead engagement partner.

Under the pre-approval policy, before engagement of the independent auditors for the next year's audit, the independent auditors will submit (1) a description of all services anticipated to be rendered, as well as an estimate of the fees for each of the services, for the Audit and Oversight Committee to approve, and (2) written confirmation that the performance of any non-audit services is permissible and will not impact the firm's independence. Annual pre-approval will be deemed effective for a period of twelve months from the date of pre-approval, unless the Audit and Oversight Committee specifically provides for a different period. A fee level will be established for all permissible, pre-approved non-audit services. Any additional audit service, audit-related service, tax service, and other service must also be pre-approved.

The Audit and Oversight Committee delegated pre-approval authority to the Committee's Chair. The Audit and Oversight Committee Chair is required to report any pre-approval decisions at the next scheduled Audit and Oversight Committee meeting. Under the pre-approval policy, the Audit and Oversight Committee may not delegate to management its responsibilities to pre-approve services performed by the independent auditors.

Under the pre-approval policy, prohibited non-audit services are services prohibited by the Securities and Exchange Commission or by the Public Company Accounting Oversight Board (United States) to be performed by the Company's independent auditors. These services include: bookkeeping or other services related to the accounting records or financial statements of the Company; financial information systems design and implementation; appraisal or valuation services, fairness opinions or contribution-in-kind reports; actuarial services; internal audit outsourcing services; management functions or human resources; broker-dealer, investment advisor or investment banking services; legal services and expert services unrelated to the audit; services provided for a contingent fee or commission; and services related to planning, marketing or opining in favor of the tax treatment of a confidential transaction or an aggressive tax position transaction that was initially recommended, directly or indirectly, by the independent auditors. In addition, the Audit and Oversight Committee has determined that the independent auditors may not provide any services, including personal financial counseling and tax services, to any officer or other employee of the Company who serves in a financial reporting oversight role or to the chair of the Audit and Oversight Committee or to an immediate family member of these individuals, including spouses, spousal equivalents, and dependents.

Fee Table. The following table shows the fees, all of which were approved by the Audit and Oversight Committee, for professional audit services provided by Deloitte & Touche LLP for the audit of the annual financial statements of the Company and its subsidiaries for fiscal years 2018 and 2017, and fees for other services rendered during those periods. No fees were paid to Deloitte & Touche LLP pursuant to the "de minimus" exception to the pre-approval policy permitted under the Securities Exchange Act of 1934, as amended.

	2018	2017
Audit Fees [1]	$ 5,531,450	$ 5,064,125
Audit-Related Fees [2]	—	—
Tax Fees [3]	67,226	20,000
All Other Fees [4]	8,495	7,095
Total	$ 5,607,171	$ 5,091,220

(1) Audit Fees consist of fees for professional services rendered in connection with: (1) the audits of the annual financial statements of the Company and its subsidiaries, (2) the audits of the effectiveness of internal control over financial reporting, and (3) other non-recurring audit work. This category also includes reviews of financial statements included in Form 10-Q filings of the Company and its subsidiaries and services provided in connection with statutory and regulatory filings or engagements.

(2) Audit-Related Fees consist of fees for professional services that are reasonably related to the performance of the audit or review of the Company's financial statements and are not reported under "Audit Fees." No such services were received from Deloitte & Touche LLP in 2018 or 2017.

(3) Tax Fees consist of fees for professional services rendered with respect to federal and state tax compliance and tax advice. This can include preparation of tax returns, claims for refunds, payment planning, and tax law interpretation.

(4) All Other Fees consist of costs for certain employees to attend accounting/tax seminars hosted by Deloitte & Touche LLP plus the subscription cost for the use of a Deloitte & Touche LLP accounting research tool.

AUDIT AND OVERSIGHT COMMITTEE REPORT

The Audit and Oversight Committee, which is comprised solely of independent directors, oversees the integrity of the financial reporting process on behalf of the Board of WEC Energy Group, Inc. In addition, the Audit and Oversight Committee oversees compliance with legal and regulatory requirements. The Audit and Oversight Committee operates under a written charter approved by the Board, which can be found in the "Governance" section of the Company's Website at wecenergygroup.com.

The Audit and Oversight Committee is also directly responsible for the appointment, compensation, retention, and oversight of the Company's independent auditors, as well as the oversight of the Company's internal audit function.

In order to assure continuing auditor independence, the Audit and Oversight Committee periodically considers whether there should be a regular rotation of the independent external audit firm. For 2019, the Audit and Oversight Committee has appointed Deloitte & Touche LLP to remain as the Company's independent auditors, subject to stockholder ratification. The members of the Audit and Oversight Committee and other members of the Board believe that the continued retention of Deloitte & Touche LLP to serve as the Company's independent external auditor is in the best interests of the Company and its stockholders.

The Audit and Oversight Committee is directly involved in the selection of Deloitte & Touche LLP's lead engagement partner in conjunction with a mandated rotation policy and is also responsible for audit fee negotiations with Deloitte & Touche LLP.

Management is responsible for the Company's financial reporting process, the preparation of consolidated financial statements in accordance with generally accepted accounting principles, and the system of internal controls and procedures designed to provide reasonable assurance regarding compliance with accounting standards and applicable laws and regulations. The Company's independent auditors are responsible for performing an independent audit of the Company's consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States) (the "PCAOB") and issuing a report thereon.

The Audit and Oversight Committee held six meetings during 2018. Meetings are designed to facilitate and encourage open communication among the members of the Audit and Oversight Committee, management, the internal auditors, and the Company's independent auditors, Deloitte & Touche LLP. During these meetings, we reviewed and discussed with management, among other items, the Company's unaudited quarterly and audited annual financial statements and the system of internal controls designed to provide reasonable assurance regarding compliance with accounting standards and applicable laws.

We have reviewed and discussed with management and the Company's independent auditors the Company's audited consolidated financial statements and related footnotes for the fiscal year ended December 31, 2018, and the independent auditor's report on those financial statements. Management represented to us that the Company's financial statements were prepared in accordance with generally accepted accounting principles. Deloitte & Touche LLP presented the matters required to be discussed with the Audit and Oversight Committee by PCAOB Auditing Standard No. 1301, *Communications with Audit Committees*. This review included a discussion with management and the independent auditors about the quality of the Company's accounting principles, the reasonableness of significant estimates and judgments, and the disclosures in the Company's financial statements, as well as the disclosures relating to critical accounting policies.

In addition, we received the written disclosures and correspondence relative to the auditors' independence from Deloitte & Touche LLP, as required by applicable requirements of the PCAOB regarding Deloitte & Touche LLP's communications with the Audit and Oversight Committee concerning independence. The Audit and Oversight Committee discussed with Deloitte & Touche LLP its independence and also considered the compatibility of non-audit services provided by Deloitte & Touche LLP with maintaining its independence.

Based on these reviews and discussions, the Audit and Oversight Committee recommended to the Board that the audited financial statements be included in WEC Energy Group's Annual Report on Form 10-K for the fiscal year ended December 31, 2018 and filed with the Securities and Exchange Commission.

Respectfully submitted to WEC Energy Group stockholders by the Audit and Oversight Committee of the Board.

The Audit and Oversight Committee

Thomas J. Fischer, Committee Chair
John F. Bergstrom
Barbara L. Bowles
Patricia W. Chadwick
Danny L. Cunningham
Henry W. Knueppel

WEC ENERGY GROUP COMMON STOCK OWNERSHIP

Beneficial Ownership. The following table lists the beneficial ownership of WEC Energy Group common stock of each director, director nominee, NEO, and of all of the directors and executive officers as a group as of January 31, 2019. In general, "beneficial ownership" includes those shares as to which the indicated persons have voting power or investment power and stock options that are exercisable currently or within 60 days of January 31, 2019. Included are shares owned by each individual's spouse, minor children, or any other relative sharing the same residence, as well as shares held in a fiduciary capacity or held in WEC Energy Group's Stock Plus Investment Plan and WEC Energy Group's 401(k) plans. None of these persons beneficially owns more than 1% of the outstanding common stock.

	Shares Beneficially Owned [1]		
Name	Shares Owned [2] [3] [4]	Option Shares Exercisable Within 60 Days	Total
John F. Bergstrom	13,499	—	13,499
Barbara L. Bowles	22,301	—	22,301
William J. Brodsky	43,031	—	43,031
Albert J. Budney, Jr.	6,154	—	6,154
Patricia W. Chadwick	23,403	—	23,403
Curt S. Culver	1,981	—	1,981
Danny L. Cunningham	4,156	—	4,156
William M. Farrow III	4,095	—	4,095
Thomas J. Fischer	41,176	—	41,176
J. Kevin Fletcher	12,395	27,105	39,500
Margaret C. Kelsey	3,926	—	3,926
J. Patrick Keyes	18,998	—	18,998
Gale E. Klappa	204,870	849,685	1,054,555
Henry W. Knueppel	18,391	—	18,391
Frederick D. Kuester	62,599	—	62,599
Scott J. Lauber	19,759	31,620	51,379
Allen L. Leverett	82,502	604,075	686,577
Ulice Payne, Jr.	29,764	—	29,764
Mary Ellen Stanek	4,582	—	4,582
All directors and executive officers as a group (25 persons)	664,865 [5]	1,700,345	2,365,210 [6]

(1) Information on beneficially owned shares is based on data furnished by the specified persons and is determined in accordance with Rule 13d-3 under the Securities Exchange Act of 1934, as amended, as required for purposes of this proxy statement. It is not necessarily to be construed as an admission of beneficial ownership for other purposes.

(2) Certain directors, NEOs, and other executive officers also hold share units in the WEC Energy Group phantom common stock account under WEC Energy Group's deferred compensation plans as indicated: Mr. Bergstrom (72,527), Ms. Bowles (1,503), Mr. Budney (7,118), Mr. Culver (101,447), Mr. Cunningham (1,461), Mr. Fischer (7,593), Ms. Kelsey (3,083), Mr. Keyes (1,148), Mr. Lauber (1,223), Mr. Leverett (80), Mr. Payne (2,114), Ms. Stanek (25,665), and all directors and executive officers as a group (258,523). Share units are intended to reflect the performance of WEC Energy Group common stock and are payable in cash. While these units do not represent a right to acquire WEC Energy Group common stock, have no voting rights, and are not included in the number of shares reflected in the "Shares Owned" column in the table above, the Company listed them in this footnote because they represent an additional economic interest of the directors, NEOs, and other executive officers that is tied to the performance of WEC Energy Group common stock.

(3) Each individual has sole voting and investment power as to all shares listed for such individual, except the following individuals have shared voting and/or investment power (included in the table above) as indicated: Mr. Bergstrom (6,000), Mr. Brodsky (41,050), Mr. Budney (902), Mr. Fischer (37,195), Mr. Klappa (5,000), Mr. Knueppel (16,410), Mr. Leverett (66,511), Ms. Stanek (2,601), and all directors and executive officers as a group (175,669).

(4) The directors and executive officers hold shares of restricted stock (included in the table above) over which the holders have sole voting but no investment power: Mr. Bergstrom (1,981), Ms. Bowles (1,981), Mr. Brodsky (1,981), Mr. Budney (1,981), Ms. Chadwick (1,981), Mr. Culver (1,981), Mr. Cunningham (1,981), Mr. Farrow (1,981), Mr. Fischer (1,981), Mr. Fletcher (5,469), Ms. Kelsey (2,887), Mr. Klappa (18,565), Mr. Knueppel (1,981), Mr. Kuester (48,586), Mr. Lauber (4,864), Mr. Leverett (12,817), Mr. Payne (1,981), Ms. Stanek (1,981), and all directors and executive officers as a group (126,739).

(5) None of the shares beneficially owned by the directors, NEOs, or all directors and executive officers as a group are pledged as security.

(6) Represents approximately 0.75% of total WEC Energy Group common stock outstanding on January 31, 2019.

Owners of More than 5%. The following table shows stockholders who reported beneficial ownership of more than 5% of WEC Energy Group common stock, based on the information they have reported. This information is based upon Schedule 13G filed with the SEC and reflects stock holdings as of December 31, 2018. These holdings have not been otherwise adjusted for stock activity that may have occurred since December 31, 2018, if any.

Name and Address [1]	Voting Authority		Dispositive Authority		Total Shares Beneficially Owned	Percent of WEC Common Stock
	Sole	Shared	Sole	Shared		
The Vanguard Group, Inc. 100 Vanguard Blvd. Malvern, PA 19355	423,111	217,737	35,123,405	579,385	35,702,790	11.31%
BlackRock, Inc. 55 East 52nd Street New York, NY 10055	26,244,500	—	29,050,912	—	29,050,912	9.20%
State Street Corporation One Lincoln Street Boston, MA 02111	—	14,433,070	—	16,105,068	16,112,281	5.10%

(1) Filed on behalf of itself and certain of its subsidiaries.

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Securities Exchange Act of 1934, as amended, requires the Company's executive officers, directors, and persons owning more than 10% of WEC Energy Group's common stock to file reports of ownership and changes in ownership of equity and derivative securities of WEC Energy Group with the SEC and the New York Stock Exchange. Specific due dates for those reports have been established by the SEC, and the Company is required to disclose in this proxy statement any failure to file by those dates during the 2018 fiscal year. To the Company's knowledge, based on information provided by the reporting persons, all applicable reporting requirements for fiscal year 2018 were complied with in a timely manner, except that (i) due to administrative error, one acquisition of phantom stock units by each of William Guc, Tom Metcalfe and James Schubilske was reported late; and (ii) due to broker error, one Form 5 was filed for Frederick Kuester to report additional shares of common stock not previously reported on his Form 3 filed January 29, 2018 and to disclose one purchase of shares of common stock that was not previously reported on a Form 4, as required.

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Compensation Committee Interlocks and Insider Participation. None of the persons who served as members of the Compensation Committee during 2018 was an officer or employee of the Company during 2018 or at any time in the past nor had reportable transactions with the Company.

During 2018, none of our executive officers served as a member of the compensation committee or as a director of another entity, one of whose executive officers served on the Compensation Committee or as a director of the Company.

INFORMATION RELATED TO THE ANNUAL MEETING

BUSINESS OF THE ANNUAL MEETING

Proposal 1: Election of Thirteen Directors for Terms Expiring in 2020. The Board recommends a vote **FOR** each of the nominees. The thirteen individuals will be elected as directors if the number of votes cast in person or by proxy at the Meeting favoring such nominee's election exceeds the number of votes cast opposing that nominee's election. Presuming a quorum is present, shares not voted, whether by broker non-vote, abstention, or otherwise, have no effect on the outcome of this matter.

Proposal 2: Advisory Vote to Approve Compensation of the Named Executive Officers, Commonly Referred to as a "Say-on-Pay" Vote. The Board recommends a vote **FOR** this proposal. Approval, on a non-binding, advisory basis, of the compensation of the NEOs requires the affirmative vote of a majority of the votes cast in person or by proxy at the Meeting. Presuming a quorum is present, shares not voted, whether by broker non-vote, abstention, or otherwise, have no effect on the outcome of this matter. Because your vote is advisory, it will not be binding on the Board or the Company. However, the Compensation Committee will review the voting results and take them into consideration.

Proposal 3: Ratification of Deloitte & Touche LLP as Independent Auditors for 2019. The Board recommends a vote **FOR** this proposal. Ratification of the independent auditors requires the affirmative vote of a majority of the votes cast in person or by proxy at the Meeting. Presuming a quorum is present, shares not voted, whether by abstention or otherwise, have no effect on the outcome of this matter.

The Company is not aware of any other matters that will be voted on. If a matter does properly come before the Meeting, the persons named as the proxies in the form of proxy will vote the proxy at their discretion.

VOTING INFORMATION

Who can vote?

Common stockholders as of the close of business on the Record Date, February 21, 2019, can vote. Each outstanding share of WEC Energy Group common stock is entitled to one vote upon each matter presented. A list of stockholders entitled to vote will be available for inspection by stockholders at WEC Energy Group's principal business office, 231 W. Michigan St., Milwaukee, Wisconsin 53203, prior to the Meeting. The list will also be available at the Meeting.

How do I vote?

There are several ways to vote:

- By Internet. The Company encourages you to vote this way.
- By toll-free, touch-tone telephone.
- By completing and mailing your proxy card.
- By written ballot at the Meeting.

If you wish to vote through the Internet or by telephone, please follow the instructions on your Notice Regarding the Availability of Proxy Materials, proxy card, or the information forwarded to you by your bank or broker, as applicable. The Internet and telephone voting facilities will close at 10:59 p.m., Central time, on Wednesday, May 1, 2019.

If you are a participant in WEC Energy Group's Stock Plus Investment Plan ("Stock Plus") or own shares through investments in the WEC Energy Group Common Stock ESOP Fund in any of WEC Energy Group's 401(k) plans, your proxy will serve as voting instructions for your shares held in those plans. The administrator for Stock Plus and the trustee for WEC Energy Group's 401(k) plans will vote your shares as you direct. If a proxy is not returned for shares held in Stock Plus, the administrator will not vote those shares. If a proxy is not returned for shares held in WEC Energy Group's 401(k) plans, the trustee will vote those shares in the same proportion that all shares in the WEC Energy Group Common Stock ESOP Fund in each respective 401(k) plan, for which voting instructions have been received, are voted.

If you are a beneficial owner and your bank or broker holds your shares in its name, they are permitted to vote your shares in the ratification of the independent auditors even if the broker does not receive voting instructions from you. However, for matters considered non-routine, which includes proposals 1 and 2, your broker or other record holder of your shares will not be permitted to vote your shares unless you provide voting instructions. If your shares are held in the name of a broker, bank or other holder of record, you are invited to attend the Meeting, but may not vote at the Meeting unless you bring a legal proxy from your broker, bank, or other holder of record.

What does it mean if I get more than one proxy?

It means your shares are held in more than one stock account. **Please vote all proxies** to ensure all of your shares are counted.

What constitutes a quorum?

As of the February 21, 2019 Record Date, there were 315,450,338 shares of WEC Energy Group common stock outstanding. In order to conduct the Meeting, a majority of the outstanding shares entitled to vote must be represented in person or by proxy. This is known as a "quorum." Abstentions and shares which are the subject of broker non-votes will count toward establishing a quorum.

Can I change my vote?

You may change your vote or revoke your proxy at any time prior to the closing of the polls by any of the following methods:

- Entering a new vote by Internet or phone;
- Returning a later-dated proxy card;
- Voting in person at the Meeting; or
- Notifying WEC Energy Group's Corporate Secretary by written revocation letter.

The Corporate Secretary is Margaret C. Kelsey. Any revocation should be filed with her at WEC Energy Group's principal business office, 231 W. Michigan St., PO Box 1331, Milwaukee, Wisconsin 53201.

Attendance at the Meeting will not, in itself, constitute revocation of a proxy. All shares entitled to vote and represented by properly completed proxies timely received and not revoked will be voted as you direct. If no direction is given in a properly completed proxy, the proxy will be voted as the Board recommends.

Who conducts the proxy solicitation?

The Board is soliciting these proxies. WEC Energy Group will bear the cost of the solicitation of proxies. The Company contemplates that proxies will be solicited principally through the use of the mail, but employees of WEC Energy Group or our subsidiaries may solicit proxies by telephone, personally, or by other communications, without compensation apart from their normal salaries. WEC Energy Group has retained Morrow Sodali LLC to assist in the solicitation of proxies for a fee of $23,000 plus reimbursement of expenses. WEC Energy Group will also reimburse brokers, banks, and other nominees for forwarding proxy materials to beneficial stockholders.

Who will count the votes?

Computershare, which will also serve as Inspector of Election, will tabulate the vote. Computershare is the Company's transfer agent.

Where can I find the voting results from the Meeting?

The Meeting voting results will be published in a Form 8-K, available no later than May 8, 2019, on the Company's website, wecenergygroup.com, under the "Investors" section.

ELECTRONIC ACCESS TO ANNUAL MEETING INFORMATION

Why did I receive a separate Notice Regarding the Availability of Proxy Materials (Notice) instead of printed proxy materials?

Pursuant to rules adopted by the SEC, we are providing access to our proxy materials over the Internet. Accordingly, we began mailing a separate Notice to stockholders on or about March 21, 2019, instead of a full set of our printed proxy materials. The Notice is not a proxy card and cannot be used to vote your shares. However, the Notice includes instructions on how to access our proxy materials online and vote your shares.

You may request a printed set of proxy materials by (1) logging on to www.envisionreports.com/wec and following the applicable instructions, (2) calling 866-641-4276, or (3) sending an email requesting a paper copy of current meeting materials to investorvote@computershare.com with "Proxy Materials WEC Energy Group" in the subject line and your full name and address plus the number located in the shaded bar on the Notice.

If your shares are held by a broker, trustee, bank, or other nominee, please refer to the instructions provided by such record holder on how to access our proxy materials and vote.

What practices may stockholders follow that are friendly to the environment and help reduce printing and postage costs?

Stockholders may wish to participate in the following:

- **View the following documents online at www.envisionreports.com/wec:**
  - Notice of Annual Meeting
  - Proxy Statement
  - 2018 Annual Report
  - Form of Proxy

- **Vote your proxy online or by telephone. Page P-8**

- **Choose to receive future proxy materials and annual reports electronically instead of receiving paper copies.**

  If you are a registered stockholder and received a paper copy of our proxy materials or a paper notice this year, you may elect to receive access to future copies of these documents and other stockholder communications (e.g., investment plan statements, tax documents, and more) electronically by (1) following the instructions when voting by Internet or by telephone, or (2) registering for our eDelivery paperless communication program.

  If your shares are held by a broker, trustee, bank or other nominee, please refer to the instructions provided by such record holder on how to elect to receive access to our future proxy materials and annual reports online.

  By delivering our proxy materials electronically, we can provide you with the information you need quickly, efficiently, and in a more cost-effective manner.

- **Choose our eDelivery paperless communication program for all your stockholder needs.**

  Electronic distribution gives stockholders faster delivery of account documents and saves the Company and our stockholders the cost of printing and mailing these materials. eDelivery also provides you with fast and secure 24/7 online access to proxy materials, investment plan statements, tax documents, and more. You may access your registered stockholder account and sign up for eDelivery at www.computershare.com/investor.

- **Sign up for Householding.**

  “Householding” is a delivery method that allows for only one paper copy of the Annual Report and Proxy Statement to be delivered to stockholders who reside at the same address.

  If you are a registered stockholder and received multiple paper copies of the Annual Report and Proxy Statement, you may wish to contact the Company’s transfer agent, Computershare, at 800-558-9663, to request householding, or you may provide written instructions to WEC Energy Group, c/o Computershare, PO 505000, Louisville, KY 40233-5000. If you wish to receive separate copies of the Annual Report and Proxy Statement now or in the future, or to discontinue householding entirely, you may contact the Company’s transfer agent using the contact information provided above. Upon request, the Company will promptly send a separate copy of the document. Whether or not a stockholder is householding, each stockholder will continue to receive a proxy card. If your shares are held through a bank, broker, or other holder of record, you may request householding by contacting the holder of record.

ANNUAL MEETING ATTENDANCE

How do I pre-register to attend the Annual Meeting?

The Meeting is open to all stockholders of WEC Energy Group. **You must pre-register to reserve an admission ticket** and then present your government-issued photo identification at the door in order to attend.

If you would like to attend, please contact Stockholder Services by email at wec.stockholder-services.contact@wecenergygroup.com or by telephone at 800-881-5882 to reserve an admission ticket. If you hold your shares in “street name” through an intermediary, such as a bank, brokerage firm, or other nominee, and you would like to attend the Meeting, please send us a written request for an admission ticket either by regular mail, fax, or email, along with proof of share ownership, such as a bank, or brokerage firm account statement, a copy of the voting instruction card provided by your broker, or a letter from the broker, trustee, bank or nominee holding your shares to: Stockholder Services, 231 W. Michigan Street, PO Box 1331, Milwaukee, Wisconsin 53201; fax: 414-221-3888; or email: wec.stockholder-services.contact@wecenergygroup.com.

Requests to reserve admission tickets will be processed in the order in which they are received and must be received no later than five business days before the Meeting, or Thursday, April 25, 2019. If we cannot confirm you are a registered stockholder or beneficial owner, we will contact you for further information.

Admission tickets will be available for pick-up at the Meeting. All Meeting attendees will be asked to present a government-issued photo identification card before receiving a ticket. We will then verify your name against our stockholder list. If you own shares in the name of your broker, bank, or other nominee ("street name"), you should bring your proof of share ownership with you to the Meeting. If we cannot verify that you are a stockholder, you may not be admitted to the Meeting.

The Meeting will begin promptly at 10:00 a.m., Central time. Check-in will begin at 9:00 a.m. Please allow ample time for check-in procedures.

What attendance guidelines apply to the Annual Meeting?

If you plan to attend the Meeting, please review the following attendance guidelines:

- **You must pre-register and reserve an admission ticket in order to attend.**
- You will be asked to check in upon entry into the R. John Buuck Field House and present government-issued photo identification, such as a driver's license, state identification card, or passport. We will verify your name against our stockholder list and will then provide you with an admission ticket.
- The Company reserves the right to inspect all items, including handbags and briefcases, prior to admittance.
- The business of the Meeting will follow as set forth in the agenda, which you will receive upon check-in.
- Stockholder questions and comments related to the business of the Company will be addressed only during the question and answer portion of the agenda. If you wish to speak, please go to the nearest microphone and wait to be recognized by the Chairman. State your name before asking your question. Questions from the floor are limited to three minutes to provide an opportunity for as many stockholders as possible.
- The use of cameras, recording devices, and other electronic devices will not be permitted during the Meeting except by those employed by the Company to provide a record of the proceedings. Please silence all cell phones and other electronic devices.
- No firearms or weapons will be allowed in the Meeting facilities.
- No signs, banners, placards, handouts, and similar materials will be allowed on Meeting premises.

Attendees who fail to comply with these guidelines risk expulsion from the Meeting. In the event of a disruption, the Chairman may immediately adjourn the Meeting and declare the polls open for such period of time as he may determine to receive votes by proxy or ballot on items of business properly brought before the Meeting.

Who do I contact if I have questions about the Annual Meeting?

If you need more information about the Meeting, call us at 800-881-5882, or write to Stockholder Services, 231 W. Michigan Street, PO Box 1331, Milwaukee, Wisconsin 53201.

* There is no parking at the Annual Meeting site. Please park at the North Shore Cinema only (11700 N. Port Washington Road, Mequon, WI 53092). Shuttle buses will run from the parking site to the Annual Meeting site.

MAP TO ANNUAL MEETING



STOCKHOLDER NOMINEES AND PROPOSALS

Stockholders wishing to propose director candidates for consideration and recommendation by the Corporate Governance Committee for election at the 2020 Annual Meeting of Stockholders must submit the candidates' names and qualifications to the Corporate Governance Committee no later than November 1, 2019 via the Corporate Secretary, Margaret C. Kelsey. Stockholders may also propose director candidates for consideration and recommendation by the Board by following the guidelines outlined in the Company's bylaws and summarized below.

Stockholders who intend to have a proposal considered for inclusion in the Company's proxy materials for presentation at the 2020 Annual Meeting of Stockholders must submit the proposal to the Company no later than November 22, 2019.

Under our proxy access bylaw, if a stockholder (or a group of up to 20 stockholders) who has owned at least 3% of our shares of common stock for at least three years and has complied with the other requirements set forth in the Company's bylaws wants us to include director nominees (up to the greater of two nominees or 20% of the Board) in our proxy statement for the 2020 Annual Meeting of Stockholders, the nominations must be received by our Corporate Secretary and must arrive at the Company in a timely manner, between 120 and 150 days prior to the anniversary of the date our proxy statement was first sent to stockholders in connection with our last annual meeting, which would be no earlier than October 23, 2019 and no later than November 22, 2019.

Stockholders who intend to present a proposal or director nominee at the 2020 Annual Meeting of Stockholders without inclusion of such proposal or nominee in the Company's proxy materials, are required to provide notice of such proposal or nomination, containing the information required by the Company's bylaws, to the Company at least 70 days and not more than 100 days prior to the scheduled date of the 2020 Annual Meeting of Stockholders. The 2020 Annual Meeting of Stockholders is tentatively scheduled for May 7, 2020.

Correspondence regarding the above should be directed to the Corporate Secretary, Margaret C. Kelsey, at the Company's principal business office, 231 W. Michigan Street, PO Box 1331, Milwaukee, Wisconsin 53201.

AVAILABILITY OF FORM 10-K

A copy (without exhibits) of WEC Energy Group's Annual Report on Form 10-K for the fiscal year ended December 31, 2018, as filed with the SEC, is available without charge to any stockholder of record or beneficial owner of WEC Energy Group common stock by writing to the Corporate Secretary, Margaret C. Kelsey, at the Company's principal business office, 231 W. Michigan Street, PO Box 1331, Milwaukee, Wisconsin 53201. The WEC Energy Group consolidated financial statements and certain other information found in the Form 10-K are provided in our 2018 Annual Financial Statements and Review of Operations. The Form 10-K, along with this proxy statement and all of WEC Energy Group's other filings with the SEC, is also available in the "Investors" section of the Company's Website at wecenergygroup.com.

APPENDIX A – EARNINGS AND EARNINGS PER SHARE GAAP RECONCILIATION

Net Income - Common Stockholders (in millions)	2017
WEC Energy Group GAAP	$ 1,203.7
Tax benefit related to Tax Cuts and Jobs Act of 2017	(206.7)
WEC Energy Group adjusted net income	$ 997.0

Diluted Earnings Per Share	2017	2016	2015	2014
WEC Energy Group GAAP EPS	$ 3.79	$ 2.96	$ 2.34	$ 2.59
Tax benefit related to Tax Cuts and Jobs Act of 2017	(0.65)	—	—	—
Acquisition costs	—	0.01	0.30	0.06
WEC Energy Group adjusted EPS	$ 3.14	$ 2.97	$ 2.64	$ 2.65

We have provided adjusted earnings (non-GAAP earnings) as a complement to, and not as an alternative to, reported earnings presented in accordance with GAAP. For 2017, adjusted earnings exclude a one-time reduction in income tax expense related to a revaluation of our deferred taxes as a result of the Tax Legislation. For 2014 through 2016, adjusted earnings exclude costs related to the acquisition of Integrys. Neither of these items is indicative of the Company's operating performance. Therefore, we believe that the presentation of adjusted earnings is relevant and useful to investors to understand WEC Energy Group's operating performance. Management uses such measures internally to evaluate the Company's performance and manage its operations.

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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

231 W. Michigan St.
P.O. Box 1331
Milwaukee, WI 53201

414-221-2345
wecenergygroup.com

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190090-03-GJ-CG-27K 1517

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2018

OR

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

For the transition period from _____ to _____

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	IRS Employer Identification No.
001-01245	**WISCONSIN ELECTRIC POWER COMPANY** (A Wisconsin Corporation) 231 West Michigan Street P. O. Box 2046 Milwaukee, WI 53201 414-221-2345	39-0476280

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

None

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

Serial Preferred Stock, 3.60% Series, $100 Par Value
Six Per Cent. Preferred Stock, $100 Par Value

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

Yes [ ] No [X]

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

Yes [ ] No [X]

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes [X] No [ ]

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).

Yes [X] No [ ]

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

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

Large accelerated filer [ ]	Accelerated filer [ ]
Non-accelerated filer [X]	Smaller reporting company [ ]
	Emerging growth company [ ]

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

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes [ ] No [X]

As of June 30, 2018 (and currently), all of the common stock of Wisconsin Electric Power Company is held by WEC Energy Group, Inc.

State the aggregate market value of the voting and non-voting common equity held by non-affiliates of the Registrant.

None.

Number of shares outstanding of each class of common stock, as of January 31, 2019

Common Stock, $10 par value, 33,289,327 shares outstanding

Documents incorporated by reference:

Portions of Wisconsin Electric Power Company's Definitive information statement on Schedule 14C for its Annual Meeting of Shareholders, to be held on April 25, 2019, are incorporated by reference into Part III hereof.

WISCONSIN ELECTRIC POWER COMPANY
ANNUAL REPORT ON FORM 10-K
For the Year Ended December 31, 2018
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GLOSSARY OF TERMS AND ABBREVIATIONS

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

Subsidiaries and Affiliates	
ATC	American Transmission Company LLC
Bluewater	Bluewater Natural Gas Holding, LLC
Bostco	Bostco LLC
Integrys	Integrys Holding, Inc.
UMERC	Upper Michigan Energy Resources Corporation
WBS	WEC Business Services LLC
WE	Wisconsin Electric Power Company
We Power	W.E. Power, LLC
WEC Energy Group	WEC Energy Group, Inc.
WG	Wisconsin Gas LLC
Wispark	Wispark LLC
WPS	Wisconsin Public Service Corporation

Federal and State Regulatory Agencies	
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	United States Internal Revenue Service
MDEQ	Michigan Department of Environmental Quality
MPSC	Michigan Public Service 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
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
NOx	Nitrogen Oxide
SO_2	Sulfur Dioxide

Measurements	
Dth	Dekatherm
MW	Megawatt
MWh	Megawatt-hour

Other Terms and Abbreviations

AIA	Affiliated Interest Agreement
ARR	Auction Revenue Right
Compensation Committee	Compensation Committee of the Board of Directors of WEC Energy Group, Inc.
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
ROE	Return on Equity
RTO	Regional Transmission Organization
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

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, effective tax rates, pension and OPEB plans, fuel costs, sources of electric energy supply, coal and natural gas deliveries, remediation costs, environmental matters, liquidity and capital resources, and other matters.

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

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

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

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

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

- The timely completion of capital projects within budgets, as well as the recovery of the related costs through rates;

- The impact of federal, state, and local legislative and/or regulatory changes, including changes in rate-setting policies or procedures, deregulation and restructuring of the electric and/or natural gas utility industries, transmission or distribution system operation, the approval process for new construction, reliability standards, pipeline integrity and safety standards, allocation of energy assistance, energy efficiency mandates, and tax laws that affect our ability to use production tax credits and investment tax credits;

- The remaining uncertainty surrounding the Tax Legislation enacted in December 2017, including implementing regulations and IRS interpretations, the amount to be returned to our ratepayers, and its impact, if any, on our 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 WEC Energy Group's 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 or us;
- Costs and effects of litigation, administrative proceedings, investigations, settlements, claims, and inquiries;
- 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 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;
- Potential business strategies to acquire and dispose of assets or businesses, which cannot be assured to be completed timely or within budgets;
- 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 WEC Energy Group's enterprise systems with those of its other utilities;
- 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.

PART I

ITEM 1. BUSINESS

A. INTRODUCTION

In this report, when we refer to "us," "we," "our," or "ours," we are referring to Wisconsin Electric Power Company. The term "utility" refers to our regulated activities, while the term "non-utility" refers to our activities that are not regulated, as well as the activities of our former subsidiary, Bostco, which was dissolved in October 2018. References to "Notes" are to the Notes to the Consolidated Financial Statements included in this Annual Report on Form 10-K. See Note 2, Dispositions, for more information on the sale of the remaining assets of Bostco and the dissolution of this entity.

We are a subsidiary of WEC Energy Group and were incorporated in the state of Wisconsin in 1896. We maintain our principal executive offices in Milwaukee, Wisconsin and serve customers in Wisconsin and served customers in the Upper Peninsula of Michigan through December 31, 2016. Effective January 1, 2017, we transferred our electric customers (other than Tilden, which is discussed in more detail below) and distribution assets located in the Upper Peninsula of Michigan to UMERC, a stand-alone utility owned by WEC Energy Group. See Note 21, Regulatory Environment, for more information on UMERC.

We conduct our business primarily through our utility reportable segment. Effective January 1, 2017, we transferred our investment in ATC to another subsidiary of WEC Energy Group. See Note 16, Investment in American Transmission Company, for more information.

For more information about our utility operations, including financial and geographic information, see Note 17, Segment Information, and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations.

Available Information

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

B. UTILITY SEGMENT

ELECTRIC UTILITY OPERATIONS

We are the largest electric utility in the state of Wisconsin. We generate and distribute electric energy to customers located in southeastern Wisconsin (including the metropolitan Milwaukee area), east central Wisconsin, and northern Wisconsin, and serve an iron ore mine customer, Tilden, in the Upper Peninsula of Michigan.

Through December 31, 2016, we served other electric customers in the Upper Peninsula of Michigan. Effective January 1, 2017, we transferred our electric customers (other than Tilden) and electric distribution assets located in the Upper Peninsula of Michigan to UMERC, a stand-alone utility owned by WEC Energy Group. See Note 3, Related Parties, and Note 21, Regulatory Environment, for more information. UMERC currently meets its market obligations through power purchase agreements with us and WPS. UMERC will begin to generate electricity when its new generation solution in the Upper Peninsula of Michigan begins commercial operation, which is expected to occur during the second quarter of 2019.

Operating Revenues

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

	Year Ended December 31	
(in millions)	**2017**	**2016**
Operating revenues		
Residential	$ 1,178.4	$ 1,243.3
Small commercial and industrial	1,015.9	1,046.1
Large commercial and industrial	657.3	699.3
Other	21.2	21.0
Total retail revenues	2,872.8	3,009.7
Wholesale	118.8	88.7
Resale	238.0	224.4
Steam	23.3	27.2
Other operating revenues *	83.3	90.6
Total operating revenues	$ 3,336.2	$ 3,440.6

* Includes SSR revenues, rent income, and ancillary revenues, partially offset by revenues from Tilden that are being deferred until a future rate proceeding. For more information, see the discussion below under the heading "Large Electric Retail Customers."

Electric Sales

Our electric energy deliveries included supply and distribution sales to retail and wholesale customers. In 2018, retail electric revenues accounted for 90.7% of total electric operating revenues, while wholesale and resale electric revenues accounted for 8.2% of total electric operating revenues. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Utility Segment Contribution to Operating Income for information on MWh sales by customer class.

We are authorized to provide retail electric service in designated territories in the state of Wisconsin, as established by indeterminate permits and boundary agreements with other utilities. Although we no longer provide electric service in certain territories in the state of Michigan, we continue, on an interim basis, to provide service to the Tilden mine located in the Upper Peninsula of Michigan. See the discussion below under the heading "Large Electric Retail Customers."

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

Steam Sales

We have a steam utility that generates, distributes, and sells steam supplied by VAPP to customers in metropolitan Milwaukee, Wisconsin. Steam is used by customers for processing, space heating, domestic hot water, and humidification. Annual sales of steam fluctuate from year to year based on system growth and variations in weather conditions. In April 2016, we sold the MCPP steam generation and distribution assets, located in Wauwatosa, Wisconsin. MCPP primarily provided steam to the Milwaukee Regional Medical Center hospitals and other campus buildings. See Note 2, Dispositions, for more information.

Electric Sales Forecast

Our service territory experienced growth in weather-normalized retail electric sales in 2018 due to customer growth. We currently forecast retail electric sales volumes, excluding the Tilden iron ore mine located in the Upper Peninsula of Michigan, to grow between 0.5% and 1.0% over the next five years, assuming normal weather. Electric peak demand is expected to grow between flat and 0.5% over the next five years. The Tilden mine will no longer be a retail customer of ours once UMERC's new generation solution in the Upper Peninsula of Michigan begins commercial operation, which is expected to occur in the second quarter of 2019. At that time, Tilden will become a retail customer of UMERC.

Customers

	Year Ended December 31		
(in thousands)	**2018**	**2017**	**2016**
Electric customers – end of year			
Residential	**1,016.3**	1,009.1	1,026.0
Small commercial and industrial	**115.3**	114.5	116.7
Large commercial and industrial	**0.6**	0.7	0.7
Other	**2.6**	2.5	2.5
Total electric customers – end of year	**1,134.8**	1,126.8	1,145.9
Steam customers – end of year	**0.4**	0.4	0.4

Large Electric Retail Customers

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

In February 2015, Tilden, along with another affiliated iron ore mine located in the Upper Peninsula of Michigan, returned as customers after choosing an alternative electric supplier in September 2013. We entered into a contract with each of the mines to provide full requirements electric service through December 31, 2019. Since 2015, we have been deferring, and expect to continue to defer, the revenues less costs of sales from the mine sales and will apply these amounts for the benefit of Wisconsin retail electric customers in a future rate proceeding, as ordered by the PSCW.

In 2016, one of the iron ore mines closed, and the related contract for full requirements electric service was terminated. In August 2016, WEC Energy Group entered into a new agreement with Tilden under which it will purchase electric power from UMERC for 20 years for the remaining mine, contingent upon UMERC's construction of natural gas-fired generation in the Upper Peninsula of Michigan. Tilden will continue to receive full requirements electric service from us under the existing contract until UMERC's generation solution in the Upper Peninsula of Michigan begins commercial operation, which is expected to occur during the second quarter of 2019. See Note 3, Related Parties, and Note 21, Regulatory Environment, for more information.

Wholesale Customers

We provide wholesale electric service to various customers, including electric cooperatives, municipal joint action agencies, other investor-owned utilities, municipal utilities, and energy marketers. Wholesale sales accounted for 5.2%, 4.6%, and 3.2% of total electric energy sales volumes during 2018, 2017, and 2016, respectively. Wholesale revenues accounted for 3.4%, 3.6%, and 2.6% of total electric operating revenues during 2018, 2017, and 2016, respectively.

Resale

The majority of our sales for resale are sold into an energy market operated by MISO at market rates based on availability of our generation and market demand. Resale sales accounted for 15.3%, 23.5%, and 23.0% of total electric energy sales volumes during 2018, 2017, and 2016, respectively. Resale revenues accounted for 4.8%, 7.1%, and 6.5% of total electric operating revenues during 2018, 2017, and 2016, respectively. Retail fuel costs are reduced by the amount that revenue exceeds the costs of sales derived from these opportunity sales.

Electric Generation and Supply Mix

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

Our rated capacity by fuel type as of December 31, including the units we lease from We Power, is shown below. For more information on our electric generation facilities, see Item 2. Properties.

	Rated Capacity in MW [1]		
	2018	**2017**	**2016**
Coal	**2,489**	3,599	3,582
Natural gas:			
Combined cycle	**1,232**	1,182	1,140
Steam turbine [2]	**269**	240	240
Natural gas/oil peaking units [3]	**989**	982	962
Renewables [4]	**145**	191	190
Total rated capacity	**5,124**	6,194	6,114

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

[2] The natural gas steam turbine represents the rated capacity associated with VAPP.

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

[4] Includes hydroelectric, biomass, and wind generation.

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

	Estimate	Actual		
	2019	**2018**	**2017**	**2016**
Company-owned or leased generation units:				
Coal *	36.7%	**45.5%**	50.8%	49.9%
Natural gas:				
Combined cycle	22.2%	**17.7%**	14.7%	15.9%
Steam turbine	1.1%	**0.8%**	1.1%	1.2%
Natural gas/oil peaking units	0.3%	**0.8%**	0.5%	0.7%
Renewables	4.0%	**3.7%**	3.8%	3.5%
Total company-owned or leased generation units	64.3%	**68.5%**	70.9%	71.2%
Power purchase contracts:				
Nuclear	27.8%	**27.1%**	25.2%	24.6%
Natural gas	4.4%	**2.3%**	1.8%	2.4%
Renewables	1.9%	**1.3%**	1.8%	1.8%
Total power purchase contracts	34.1%	**30.7%**	28.8%	28.8%
Purchased power from MISO	1.6%	**0.8%**	0.3%	—%
Total purchased power	35.7%	**31.5%**	29.1%	28.8%
Total electric utility supply	100.0%	**100.0%**	100.0%	100.0%

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

Reshaping our Generation Fleet

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

Coal-Fired Generation

As of December 31, 2018, our coal-fired generation, including the ERGS units we lease from We Power, consists of three operating plants with a rated capacity of 2,489 MW. For more information about our operating plants, see Item 2. Properties.

We plan to retire approximately 1,500 MW of coal-fired generation by 2020, as a result of WEC Energy Group's generation reshaping plan. As part of this effort during 2018, we retired the Pleasant Prairie power plant, which accounted for approximately 1,190 MW of coal-fired generation. We are required to retire PIPP by May 31, 2019. For more information about the retirement of these plants, see Note 6, Property, Plant, and Equipment.

Natural Gas-Fired Generation

Our natural gas-fired generation, including the PWGS units we lease from We Power, consists of four operating plants, including peaking units, with a rated capacity of 2,300 MW as of December 31, 2018. For more information about our operating plants, see Item 2. Properties.

Oil-Fired Generation

Our oil-fired generation had a rated capacity of 190 MW as of December 31, 2018. We also have natural gas-fired peaking units with a rated capacity of 799 MW, which have the ability to burn oil if natural gas is not available due to delivery constraints. For more information about our operating plants, see Item 2. Properties.

Renewable Generation

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

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

Solar

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

Hydroelectric

Our hydroelectric generating system consists of 13 operating plants with a total installed capacity of 91 MW and a rated capacity of 53 MW as of December 31, 2018. All of our hydroelectric facilities follow FERC guidelines and/or regulations.

Wind

We have four wind sites, consisting of 200 turbines, with an installed capacity of 339 MW and a rated capacity of 46 MW as of December 31, 2018.

Biomass

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

Generation from Leased We Power Units

As discussed above, we also supply electricity to our customers from power plants that we lease from We Power. These plants include the ERGS units and the PWGS units. Lease payments are billed from We Power to us and then recovered in our rates as authorized by the PSCW, the MPSC, and the FERC. We operate the We Power units and are authorized by the PSCW and state law to fully recover prudently incurred operating and maintenance costs in our Wisconsin electric rates. As the operator of the units, we may request We Power to make capital improvements to, or further investments in, the units. Under the lease terms, these capital improvements or further investments will increase lease payments paid by us and should ultimately be recovered in our rates.

Electric System Reliability

The PSCW requires us to maintain a planning reserve margin above our projected annual peak demand forecast to help ensure reliability of electric service to our customers. These planning reserve requirements are consistent with the MISO calculated planning reserve margin. In 2008, the PSCW established a 14.5% reserve margin requirement for long-term planning (planning years two through ten). For short-term planning (planning year one), the PSCW requires Wisconsin utilities to follow the planning reserve margin established by MISO. MISO has a 17.1% installed capacity reserve margin requirement for the planning year from June 1, 2018, through May 31, 2019, and a 16.8% installed capacity reserve margin requirement for the planning year from June 1, 2019, through May 31, 2020. MISO's short-term reserve margin requirements experience year-to-year fluctuations, primarily due to changes in the average forced outage rate of generation within the MISO footprint.

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

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

Fuel and Purchased Power Costs

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

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

	2018	2017	2016
Coal	**$ 22.39**	$ 22.26	$ 22.68
Natural gas combined cycle	**22.05**	22.85	19.13
Natural gas/oil peaking units	**63.29**	60.44	46.99
Biomass	**97.33**	118.76	103.24
Purchased power	**45.66**	45.50	43.51

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

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

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

Coal Supply

We diversify the coal supply for our electric generating facilities by purchasing coal from several mines in Wyoming, as well as from various other states. For 2019, approximately 89% of our total projected coal requirements of 6.4 million tons are contracted under fixed-price contracts. See Note 19, Commitments and Contingencies, for more information on amounts of coal purchases and coal deliveries under contract.

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

(in thousands)	Annual Tonnage
2019	5,733
2020	1,925

Coal Deliveries

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

Midcontinent Independent System Operator Costs

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

Power Purchase Commitments

We enter into short and long-term power purchase commitments to meet a portion of our anticipated electric energy supply needs. Our power purchase commitments with unaffiliated parties are 1,279 MW per year for 2019 through 2021 and 1,033 MW per year for 2022 and 2023, which exclude planning capacity purchases. These amounts include 1,033 MW per year related to a long-term power purchase agreement for electricity generated by Point Beach. Due to the actual and planned retirement of generation resources, we have entered into purchase agreements to procure additional planning capacity in order to maintain our compliance with planning reserve requirements as established by the PSCW, MPSC, and MISO.

Other Matters

Seasonality

Our electric utility sales are impacted by seasonal factors and varying weather conditions. We sell more electricity during the summer months because of the residential cooling load. We continue to upgrade our electric distribution system, including substations, transformers, and lines, to meet the demand of our customers. Our generating plants performed as expected during the warmest periods of the summer, and all power purchase commitments under firm contract were received. During this period, we did not require public appeals for conservation, and we did not interrupt or curtail service to non-firm customers who participate in load management programs.

Competition

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

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

Environmental Matters

For information regarding environmental matters, especially as they relate to coal-fired generating facilities, see Note 19, Commitments and Contingencies.

NATURAL GAS UTILITY OPERATIONS

We are authorized to provide retail natural gas distribution service in designated territories in the state of Wisconsin, as established by indeterminate permits and boundary agreements with other utilities. We also transport customer-owned natural gas. We operate in three distinct service areas including west and south of the City of Milwaukee, the Appleton area, and areas within Iron and Vilas Counties, Wisconsin.

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

Operating Revenues

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

	Year Ended December 31	
(in millions)	**2017**	**2016**
Operating revenues		
Residential	$ 249.0	$ 238.6
Commercial and industrial	114.3	105.0
Total retail revenues	363.3	343.6
Transport	13.7	13.6
Other operating revenues *	(1.5)	(5.0)
Total operating revenues	$ 375.5	$ 352.2

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

Natural Gas Sales Forecast

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

Customers

(in thousands)	Year Ended December 31 2018	2017	2016
Customers – end of year			
Residential	**449.4**	445.9	442.0
Commercial and industrial	**39.9**	39.6	39.4
Transport	**0.8**	0.8	0.7
Total customers	**490.1**	486.3	482.1

Natural Gas Supply, Pipeline Capacity and Storage

We have been able to meet our contractual obligations with both our suppliers and our customers. For more information on our natural gas utility supply and transportation contracts, see Note 19, Commitments and Contingencies.

Pipeline and Storage Capacity

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

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

In June 2017, our parent company completed its acquisition of Bluewater. Bluewater owns natural gas storage facilities in Michigan that provide a portion of the current storage needs for our natural gas utility operations. We have entered into a long-term service agreement to take a portion of the storage from Bluewater. See Note 3, Related Parties, for more information on this transaction.

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

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

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

Combined with our storage capability, management believes that the volume of natural gas under contract is sufficient to meet our forecasted firm peak-day and seasonal demand. Our forecasted design peak-day throughput is 10.1 million therms for the 2018 through 2019 heating season. Our peak daily send-out during 2018 was 6.8 million therms on January 1, 2018.

Natural Gas Supply

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

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

Hedging Natural Gas Supply Prices

We have PSCW approval to hedge up to 60% of planned winter demand and up to 15% of planned summer demand using a mix of NYMEX-based natural gas options and futures contracts. This approval allows us to pass 100% of the hedging costs (premiums, brokerage fees and losses) and proceeds (gains) to customers through our GCRM.

To the extent that opportunities develop and physical supply operating plans are supportive, we also have PSCW approval to utilize NYMEX-based natural gas derivatives to capture favorable forward market price differentials. That approval provides for 100% of the related proceeds to accrue to our GCRM.

Seasonality

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

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

Competition

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

C. OTHER SEGMENT

Our other segment included Bostco, our non-utility subsidiary that was originally formed to develop and invest in real estate. In March 2017, we sold substantially all of the remaining assets of Bostco, and, in October 2018, Bostco was dissolved. See Note 2, Dispositions, for more information.

Prior to January 1, 2017, our other segment also included our approximate 23% ownership interest in ATC, a for-profit, transmission-only company regulated by the FERC and certain state regulatory commissions. Effective January 1, 2017, we transferred our investment in ATC to another subsidiary of WEC Energy Group. See Note 16, Investment in American Transmission Company, for more information.

D. REGULATION

In addition to the specific regulations noted below, we are also subject to regulations, where applicable, of the EPA, the WDNR, the MDEQ, the Michigan Department of Natural Resources, and the United States Army Corps of Engineers.

Rates

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

Regulated Rates	Regulatory Commission
Retail electric, natural gas, and steam	PSCW
Retail electric	MPSC *
Wholesale power	FERC

* Effective January 1, 2017, we transferred all of our electric distribution assets and customers located in the Upper Peninsula of Michigan to UMERC, with the exception of Tilden. See Note 3, Related Parties, and Note 21, Regulatory Environment, for more information.

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

Our natural gas utility operates under a GCRM as approved by the PSCW. Generally, the GCRM allows for a dollar-for-dollar recovery of prudently incurred natural gas costs.

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

We have been subject to an earnings sharing mechanism since January 2016, and will continue to be subject to it through 2019**.** See Note 21, Regulatory Environment, for more information on our earnings sharing mechanism and on how our rates are set. Orders from our respective regulators can be viewed at the following websites:

Regulatory Commission	Website
PSCW	https://psc.wi.gov/
MPSC	http://www.michigan.gov/mpsc/
FERC	http://www.ferc.gov/

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

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

	2018		2017		2016	
(in millions)	**Amount**	**Percent**	**Amount**	**Percent**	**Amount**	**Percent**
Electric						
Wisconsin	**$ 2,876.8**	**89.4%**	$ 2,901.2	87.0%	$ 2,973.3	86.4%
Michigan *	**83.8**	**2.6%**	78.2	2.3%	154.2	4.5%
FERC – Wholesale *	**258.2**	**8.0%**	356.8	10.7%	313.1	9.1%
Total	**3,218.8**	**100.0%**	3,336.2	100.0%	3,440.6	100.0%
Natural Gas – Wisconsin	**406.2**	**100.0%**	375.5	100.0%	352.2	100.0%
Total utility operating revenues	**$ 3,625.0**		$ 3,711.7		$ 3,792.8	

* Effective January 1, 2017, we transferred all of our electric distribution assets and customers located in the Upper Peninsula of Michigan to UMERC, with the exception of Tilden. UMERC currently purchases a portion of its power from us. The revenues received from UMERC are

primarily included in the FERC – Wholesale line above. See Note 3, Related Parties, and Note 21, Regulatory Environment, for additional information on UMERC.

Electric Transmission, Capacity, and Energy Markets

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

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

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

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

Other Electric Regulations

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

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

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

Other Natural Gas Regulations

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

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

E. ENVIRONMENTAL COMPLIANCE

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

Anticipated expenditures for environmental compliance and remediation issues for the next three years are included in the estimated capital expenditures described in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Capital Requirements. For a discussion of matters related to manufactured gas plant sites and air and water quality, see Note 19, Commitments and Contingencies.

F. EMPLOYEES

As of December 31, 2018, we had 2,739 employees.

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

	Number of Employees	Expiration Date of Current Labor Agreement
Local 2150 of International Brotherhood of Electrical Workers	1,611	August 15, 2020
Local 420 of International Union of Operating Engineers	360	September 30, 2021
Local 2006 Unit 1 of United Steel Workers of America	114	October 31, 2021
Local 510 of International Brotherhood of Electrical Workers	75	October 31, 2020
Total	2,160	

ITEM 1A. RISK FACTORS

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

Risks Related to Legislation and Regulation

Our business is significantly impacted by governmental regulation and oversight.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

and local taxing authorities continue to evaluate the impact of federal income tax reform, and any changes on the state or local level could lessen or increase the impacts of the Tax Legislation.

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

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

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

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

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

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

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

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

Risks Related to the Operation of Our Business

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

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

processes. Potential breakdown or failure may occur due to severe weather; catastrophic events (i.e., fires, earthquakes, explosions, tornadoes, floods, droughts, pandemic health events, etc.); significant changes in water levels in waterways; fuel supply or transportation disruptions; accidents; employee labor disputes; construction delays or cost overruns; shortages of or delays in obtaining equipment, material, and/or labor; performance below expected levels; operating limitations that may be imposed by environmental or other regulatory requirements; terrorist attacks; or cyber security intrusions. Any of these events could lead to substantial financial losses.

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

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

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

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

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

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

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

Our business requires substantial capital expenditures for investments in, among other things, capital improvements to our electric generating facilities, electric and natural gas distribution infrastructure, and other projects, including projects for environmental compliance. We also expect to invest in renewable energy generating facilities as part of WEC Energy Group's generation reshaping plan.

Achieving the intended benefits of any large construction project is subject to many uncertainties, some of which we will have limited or no control over, that could adversely affect project costs and completion time. These risks include, but are not limited to, the ability to adhere to established budgets and time frames; the availability of labor or materials at estimated costs; the ability of

contractors to perform under their contracts; strikes; adverse weather conditions; potential legal challenges; changes in applicable laws or regulations; other governmental actions; continued public and policymaker support for such projects; and events in the global economy. In addition, certain of these projects require the approval of our regulators. If construction of commission-approved projects should materially and adversely deviate from the schedules, estimates, and projections on which the approval was based, our regulators may deem the additional capital costs as imprudent and disallow recovery of them through rates, and otherwise available production tax credits and investment tax credits for renewable energy projects could be lost.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Risks Related to Economic and Market Volatility

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

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

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

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

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

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

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

Any downgrade by the rating agencies could:

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

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

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

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

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

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

Changes in commodity prices could result in:

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

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

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

The use of derivative contracts could result in financial losses.

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

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

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

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

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

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

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

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

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

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

Electric Facilities

As of December 31, 2018, we owned, or leased from We Power, the following generating assets:

Name	Location	Fuel	Number of Generating Units	Rated Capacity In MW [1]
Coal-fired plants				
ERGS	Oak Creek, WI	Coal	2	1,057 [2]
PIPP	Marquette, MI	Coal	5	353 [3]
OCPP	Oak Creek, WI	Coal	4	1,079
Total coal-fired plants			11	2,489
Natural gas-fired plants				
Concord Combustion Turbines	Watertown, WI	Natural Gas/Oil	4	359
Germantown Combustion Turbines	Germantown, WI	Natural Gas/Oil	5	270
Paris Combustion Turbines	Union Grove, WI	Natural Gas/Oil	4	360
PWGS	Port Washington, WI	Natural Gas	2	1,232
VAPP	Milwaukee, WI	Natural Gas	2	269
Total natural gas-fired plants			17	2,490
Renewables				
Hydro Plants (13 in number)	WI and MI	Hydro	30	53
Rothschild Biomass Plant	Rothschild, WI	Biomass	1	46
Blue Sky Green Field	Fond du Lac, WI	Wind	88	17
Byron Wind Turbines	Fond du Lac, WI	Wind	2	—
Glacier Hills	Cambria, WI	Wind	90	26
Montfort Wind Energy Center	Montfort, WI	Wind	20	3
Total renewables			231	145
Total system			259	5,124

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

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

As of December 31, 2018, we operated approximately 19,800 miles of overhead distribution lines and 25,000 miles of underground distribution cable, as well as 312 electric distribution substations and approximately 290,300 line transformers.

Natural Gas Facilities

As of December 31, 2018, our natural gas distribution system included approximately 11,400 miles of distribution mains connected at 25 gate stations to the pipeline transmission systems of ANR Pipeline Company, Great Lakes Transmission Company, Guardian Pipeline L.L.C., Natural Gas Pipeline Company of America, and Northern Natural Pipeline Company and approximately 414,000 natural gas lateral services. We have a liquefied natural gas storage plant that converts and stores, in liquefied form, natural gas received during periods of low consumption. The liquefied natural gas storage plant has a send-out capability of 70,000 Dth per day. Our natural gas distribution system consists almost entirely of plastic and coated steel pipe.

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

Steam Facilities

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

ITEM 3. LEGAL PROCEEDINGS

The following should be read in conjunction with Note 19, Commitments and Contingencies, and Note 21, Regulatory Environment, in this report for additional information on material legal proceedings and matters related to us.

In addition to those legal proceedings discussed in Note 19, Commitments and Contingencies, Note 21, Regulatory Environment, and below, we are currently, and from time to time, subject to claims and suits arising in the ordinary course of business. Although the results of these additional legal proceedings cannot be predicted with certainty, management believes, after consultation with legal counsel, that the ultimate resolution of these proceedings will not have a material effect on our financial statements.

Presque Isle Power Plant Matter

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

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

EXECUTIVE OFFICERS OF THE REGISTRANT

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

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

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

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

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

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

Scott J. Lauber.[(3)] Age 53.
- WEC Energy Group — Executive Vice President, Chief Financial Officer and Treasurer since October 2018. Executive Vice President and Chief Financial Officer from April 2016 to October 2018. Vice President and Treasurer from February 2013 to March 2016.
- WE — Executive Vice President, Chief Financial Officer and Treasurer since October 2018. Director since April 2016. Executive Vice President and Chief Financial Officer from April 2016 to October 2018. Vice President and Treasurer from February 2013 to March 2016.

Tom Metcalfe. Age 51.
- WE — President since November 2018. Director since January 2018. Executive Vice President - Generation from April 2016 to November 2018. Senior Vice President - Power Generation from January 2014 to March 2016.

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

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

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

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

PART II

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

There is no established public trading market for our common stock, as WEC Energy Group owns all of our outstanding common stock. See Note 8, Common Equity, for more information.

ITEM 6. SELECTED FINANCIAL DATA

WISCONSIN ELECTRIC POWER COMPANY
COMPARATIVE FINANCIAL DATA AND OTHER STATISTICS

As of or for Year Ended December 31 *(in millions)*	**2018**	**2017 ***	**2016**	**2015**	**2014**
Operating revenues	**$ 3,625.0**	$ 3,711.7	$ 3,792.8	$ 3,854.1	$ 4,059.4
Net income attributed to common shareholder	**358.3**	335.6	364.3	375.7	376.7
Total assets	**13,538.3**	13,121.6	13,371.5	13,139.6	12,597.2
Long-term debt and capital lease obligations (excluding current portion)	**5,266.8**	5,236.1	5,417.6	5,351.3	4,875.2

* Reflects the impact of the transfer of our investment in ATC to another subsidiary of WEC Energy Group and the transfer of net assets to UMERC in 2017. See Note 3, Related Parties and Note 16, Investment in American Transmission Company, for more information on these transactions.

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

CORPORATE DEVELOPMENTS

Introduction

We are a wholly owned subsidiary of WEC Energy Group, and derive revenues primarily from the distribution and sale of electricity and natural gas to retail customers in Wisconsin. We have combined common functions with WG and operate under the trade name of "We Energies." We conduct our business primarily through our utility reportable segment. See Note 17, Segment Information, for more information on our reportable business segments.

Effective January 1, 2017, our customers (other than Tilden) and electric distribution assets located in the Upper Peninsula of Michigan were transferred to UMERC, a new stand-alone utility owned by WEC Energy Group. See Note 3, Related Parties, and Note 21, Regulatory Environment, for more information.

Effective January 1, 2017, we transferred our investment in ATC to another subsidiary of WEC Energy Group. See Note 16, Investment in American Transmission Company, for more information. In March 2017, we sold the remaining real estate holdings of Bostco, and, in October 2018, Bostco was dissolved. See Note 2, Dispositions, for more information.

Corporate Strategy

Our goal is to continue to build and sustain long-term value for customers and shareholders by focusing on the fundamentals of our business: reliability; operating efficiency; financial discipline; customer care; and safety.

Reshaping Our Generation Fleet

WEC Energy Group has developed and is executing a plan to reshape its generation portfolio. This plan 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, WEC Energy Group set a new long-term goal of reducing CO_2 emissions by approximately 80% below 2005 levels by 2050. WEC Energy Group expects to retire a total of approximately 1,800 MW of coal-fired generation by 2020 across its electric utilities, and add additional natural gas-fired generating units and renewable generation, including utility-scale solar projects. As part of this effort, we retired our 1,190 MW Pleasant Prairie power plant 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. See Note 6, Property, Plant, and Equipment, for information related to the Pleasant Prairie power plant retirement and the planned retirement of the 350 MW Presque Isle power plant as part of WEC Energy Group's plan.

In December 2018, 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 our 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 our 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, these pilots have become cost effective opportunities for us 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.

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 us and our customers. This program reduces the manual effort for disconnects and reconnects and enhances outage management capabilities.

WEC Energy Group continues to focus on integrating and improving business processes and consolidating its IT infrastructure across all of its 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 earning our authorized ROE and maintaining a strong balance sheet, stable cash flows, 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, and equipment, that are no longer performing as intended, or have an unacceptable risk profile. See Note 3, Related Parties, for information on WEC Energy Group's acquisition of Bluewater. See Note 2, Dispositions, for information on the sale of the MCPP steam generation and distribution assets and Bostco's remaining real estate holdings.

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, where our employees 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:

(in millions)	Year Ended December 31 2018	2017	2016
Operating revenues	**$ 3,625.0**	$ 3,711.7	$ 3,792.8
Cost of sales	**1,262.1**	1,286.4	1,292.1
Other operation and maintenance	**1,502.4**	1,352.0	1,425.5
Depreciation and amortization	**348.1**	331.6	325.4
Property and revenue taxes	**109.9**	109.6	115.6
Operating income	**402.5**	632.1	634.2
Equity in earnings of transmission affiliate	**—**	—	55.5
Other income, net	**20.2**	13.2	4.4
Interest expense	**120.1**	117.3	117.6
Income before income taxes	**302.6**	528.0	576.5
Income tax (benefit) expense	**(56.9)**	191.2	211.0
Preferred stock dividend requirements	**1.2**	1.2	1.2
Net income attributed to common shareholder	**$ 358.3**	$ 335.6	$ 364.3

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 had no impact on net income attributed to common shareholder. See Note 12, Income Taxes, and Note 21, 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)
Operating revenues	$ (86.7)	$ (88.1)	$ (25.6)	$ 27.0
Cost of sales	24.3	—	—	24.3
Other operation and maintenance	(150.4)	(77.8)	(67.7)	(4.9)
Depreciation and amortization	(16.5)	—	—	(16.5)
Property and revenue taxes	(0.3)	—	—	(0.3)
Operating income	(229.6)	(165.9)	(93.3)	29.6
Other income, net	7.0	—	—	7.0
Interest expense	(2.8)	—	—	(2.8)
Income before income taxes	(225.4)	(165.9)	(93.3)	33.8
Income tax (benefit) expense	248.1	165.9	93.3	(11.1)
Preferred stock dividend requirements	—	—	—	—
Net income attributed to common shareholder	$ 22.7	$ —	$ —	$ 22.7

See below for additional information on the year-over year changes in our consolidated earnings.

Non-GAAP Financial Measures

The discussion below addresses the operating income contribution of our utility segment and includes 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 utility segment 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 utility segment operating performance. Our utility segment operating income for the years ended December 31, 2018, 2017, and 2016 was $402.5 million, $632.1 million, and $634.2 million, respectively. The operating income discussion below includes a table that provides the calculation of electric margins and natural gas margins, along with a reconciliation to utility segment operating income.

Utility Segment Contribution to Operating Income

Effective January 1, 2017, we transferred our electric customers (other than Tilden) located in the Upper Peninsula of Michigan to UMERC. See Note 3, Related Parties, for more information.

	Year Ended December 31		
(in millions)	**2018**	**2017**	**2016**
Electric revenues	**$ 3,218.8**	$ 3,336.2	$ 3,440.6
Fuel and purchased power	**1,010.1**	1,064.3	1,091.8
Total electric margins	**2,208.7**	2,271.9	2,348.8
Natural gas revenues	**406.2**	375.5	352.2
Cost of natural gas sold	**252.0**	222.1	200.3
Total natural gas margins	**154.2**	153.4	151.9
Total electric and natural gas margins	**2,362.9**	2,425.3	2,500.7
Other operation and maintenance	**1,502.4**	1,352.0	1,425.5
Depreciation and amortization	**348.1**	331.6	325.4
Property and revenue taxes	**109.9**	109.6	115.6
Operating income	**$ 402.5**	$ 632.1	$ 634.2

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

	Year Ended December 31		
(in millions)	**2018**	**2017**	**2016**
Operation and maintenance not included in line items below	**$ 442.7**	$ 481.8	$ 495.5
We Power [1]	**506.9**	513.0	513.2
Transmission [2]	**265.1**	251.9	273.8
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]	**98.1**	96.7	96.6
Earnings sharing mechanism [6]	**37.2**	0.1	21.1
Other	**6.9**	8.5	25.3
Total other operation and maintenance	**$ 1,502.4**	$ 1,352.0	$ 1,425.5

(1) Represents costs associated with the We Power generation units, including operating and maintenance costs, as well as the lease payments that are billed from We Power to us and then recovered in our 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 us, 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 our ATC and MISO network transmission expenses. As a result, we 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, $286.3 million, $303.8 million, and $335.3 million, respectively, of costs were billed to us by transmission providers.

(3) Represents additional transmission expense associated with the flow through of tax benefits of our 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 21, Regulatory Environment, for more information.

(4) Represents additional transmission expense associated with the May 2018 PSCW order requiring us to use 80% of our current 2018 tax benefit, including the amortization associated with the revaluation of deferred taxes, to reduce our transmission regulatory asset balance. See Note 21, 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 21, Regulatory Environment, for more information about our earnings sharing mechanism.

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

	Year Ended December 31		
	MWh *(in thousands)*		
Electric Sales Volumes	**2018**	**2017**	**2016**
Customer class			
Residential	**8,025.1**	7,648.5	8,136.6
Small commercial and industrial	**8,920.6**	8,768.4	9,061.1
Large commercial and industrial	**8,457.9**	8,340.3	9,217.6
Other	**138.7**	144.9	143.4
Total retail	**25,542.3**	24,902.1	26,558.7
Wholesale	**1,688.5**	1,600.2	1,134.2
Resale	**4,931.9**	8,144.5	8,282.1
Total sales in MWh	**32,162.7**	34,646.8	35,975.0

	Year Ended December 31		
	Therms *(in millions)*		
Natural Gas Sales Volumes	**2018**	**2017**	**2016**
Customer class			
Residential	**383.2**	344.3	341.7
Commercial and industrial	**217.9**	193.4	186.3
Total retail	**601.1**	537.7	528.0
Transport	**339.2**	314.2	323.8
Total sales in therms	**940.3**	851.9	851.8

	Year Ended December 31		
	Degree Days		
Weather *	**2018**	**2017**	**2016**
Heating (6,515 normal)	**6,685**	5,908	6,068
Cooling (731 normal)	**929**	772	991

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

2018 Compared with 2017

Electric Utility Margins

Electric utility margins decreased $63.2 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 the flow through of tax benefits of our 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 21, Regulatory Environment, for more information.

- A $15.9 million decrease in wholesale margins driven by reduced capacity rates due in part to the Tax Legislation.

- A $13.4 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, our electric utility margins 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.

- A $10.2 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 12, Income Taxes, and Note 21, Regulatory Environment, for more information.

These decreases in electric utility margins were partially offset by:

- A $44.6 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% colder than 2017. As measured by cooling degree days, 2018 was 20.3% warmer than 2017.

- 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 us for the operation and maintenance of our PIPP units under an SSR agreement we have with MISO. A portion of these payments was returned to us through the MISO allocation process and reduced transmission expense in 2017 as discussed below.

Natural Gas Utility Margins

Natural gas utility margins increased $0.8 million during 2018, compared with 2017. The most significant factor impacting the higher natural gas utility margins was a $10.6 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. This increase in natural gas utility margins was partially offset by $9.9 million of savings from the Tax Legislation that we are required to return to customers through bill credits. See Note 12, Income Taxes, and Note 21, Regulatory Environment, for more information.

Operating Income

Operating income at the utility segment decreased $229.6 million during 2018, compared with 2017. This decrease was driven by $167.2 million of higher operating expenses (which include other operation and maintenance, depreciation and amortization, and property and revenues taxes) and the $62.4 million net 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 $37.1 million increase in expense related to our earnings sharing mechanism. See Note 21, Regulatory Environment, for more information.

- A $16.5 million increase in depreciation and amortization, driven by an increase in capital expenditures as we continue to execute on our capital plan.

- A $13.2 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 $56.4 million decrease in expenses across all of our plants, in part due to the retirement of the Pleasant Prairie power plant in April 2018 and the winding down of operations in anticipation of the retirement of the PIPP on or before May 31, 2019. 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 decreased $76.9 million during 2017, compared with 2016. The significant factors impacting the lower electric utility margins were:

- A $74.1 million decrease related to lower sales volumes during 2017, primarily driven by unfavorable weather, lower overall retail use per customer, and the transfer of customers and their related sales to UMERC. 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% cooler than 2016. As measured by heating degree days, 2017 was 2.6% warmer than 2016.

- 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 us for the operation and maintenance of our PIPP units under an SSR agreement we have with MISO. A portion of these payments was returned to us through the MISO allocation process and reduced transmission expense as discussed below. See Note 21, 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 2, Dispositions, for more information.

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 increased $1.5 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 utility segment decreased $2.1 million during 2017, compared with 2016. This decrease was driven by the $75.4 million net decrease in margins discussed above, partially offset by $73.3 million of lower operating expenses (which include other operation and maintenance, depreciation and amortization, and property and revenues taxes).

We experienced lower overall operating expenses related to synergy savings resulting from WEC Energy Group's acquisition of Integrys. The significant factors impacting the decrease in operating expenses during 2017, compared with 2016, which were due in part to synergy savings, were:

- A $21.9 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.

- A $21.0 million decrease in expenses related to our earnings sharing mechanism. See Note 21, Regulatory Environment, for more information.

- A $19.1 million decrease in electric and natural gas distribution expenses, primarily related to the transfer of electric customers and their related sales to UMERC, lower metering costs, and other cost savings.

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

These decreases in operating expenses were partially offset by a $10.9 million gain recorded in April 2016 related to the sale of the MCPP. See Note 2, Dispositions, for more information.

Equity in Earnings of Transmission Affiliate

	Year Ended December 31		
(in millions)	**2018**	**2017**	**2016**
Equity in earnings of transmission affiliate	**$ —**	$ —	$ 55.5

2017 Compared with 2016

At December 31, 2016, we owned approximately 23% of ATC. Effective January 1, 2017, we transferred our investment in ATC to another subsidiary of WEC Energy Group. See Note 16, Investment in American Transmission Company, for more information.

Consolidated Other Income, Net

	Year Ended December 31		
(in millions)	**2018**	**2017**	**2016**
AFUDC – Equity	**$ 3.9**	$ 3.1	$ 4.2
Non-service credit (cost) components of net periodic benefit costs	**5.7**	(6.5)	(4.7)
Interest income	**2.2**	2.3	2.2
Other, net	**8.4**	14.3	2.7
Other income, net	**$ 20.2**	$ 13.2	$ 4.4

2018 Compared with 2017

Other income, net increased $7.0 million during 2018, compared with 2017, driven by the year-over-year increase in income from the non-service components of our net periodic pension and OPEB costs. See Note 15, Employee Benefits, for more information on our benefit costs.

2017 Compared with 2016

Other income, net increased $8.8 million during 2017, compared with 2016. The increase was driven by higher gains on property sales during 2017, compared to 2016, and the expenses we incurred in 2016 related to the disposition of certain non-utility real estate assets. These increases were partially offset by lower AFUDC during 2017 and higher costs from the non-service components of our net periodic pension and OPEB costs.

Consolidated Interest Expense

	Year Ended December 31		
(in millions)	**2018**	**2017**	**2016**
Interest expense	**$ 120.1**	$ 117.3	$ 117.6

Consolidated Income Tax Expense

	Year Ended December 31		
	2018	**2017**	**2016**
Effective tax rate	**(18.8)%**	36.2%	36.6%

2018 Compared with 2017

Our effective tax rate was (18.8)% in 2018 compared to 36.2% in 2017. This decrease was primarily due to a 39.9% effective tax rate benefit from the flow through of tax repairs in connection with the Wisconsin rate settlement. Also contributing to the decrease in the effective tax rate was the impact of the Tax Legislation. See Note 12, Income Taxes, and Note 21, Regulatory Environment for more information.

We expect our 2019 annual effective tax rate to be between (17)% and (16)%, which includes an estimated 38.5% 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 21.5% and 22.5%.

2017 Compared with 2016

Our effective tax rate was 36.2% in 2017 compared to 36.6% in 2016. This decrease in our effective tax rate was primarily due to increased renewable energy credits related to wind projects and favorable compensation expense.

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	**$ 962.2**	$ 698.0	$ 848.4	$ 264.2	$ (150.4)
Investing activities	**(640.4)**	(568.2)	(436.8)	(72.2)	(131.4)
Financing activities	**(313.9)**	(132.9)	(423.3)	(181.0)	290.4

Operating Activities

2018 Compared with 2017

Net cash provided by operating activities increased $264.2 million during 2018, compared with 2017, driven by:

- A $99.2 million increase in cash related to higher overall collections from customers, primarily due to favorable weather during 2018, compared with 2017.
- An $85.0 million increase in cash from lower payments for operating and maintenance expenses. During 2018, our payments were lower for accounts payable to related parties as well as for plant maintenance and labor costs, due in part to the retirement in 2018 of the Pleasant Prairie power plant and winding down of operations at the PIPP in anticipation of a 2019 retirement. See Note 6, Property, Plant, and Equipment, for more information about the retirement of our plants. In addition, our lease payments to We Power decreased as a result of the Tax legislation, and our payments for transmission costs decreased in 2018.
- A $54.0 million net increase in cash related to a decrease in cash paid for income taxes during 2018, compared with 2017. This increase in cash was primarily the result of the utilization of certain tax benefit carryforwards.
- A $28.9 million increase in cash due to realized gains from the settlement of our natural gas and petroleum products contracts, combined with lower cash collateral requirements related to open natural gas contracts in 2018, compared with 2017. See Note 14, Derivative Instruments, for more information.

2017 Compared with 2016

Net cash provided by operating activities decreased $150.4 million during 2017, compared with 2016, driven by:

- A $171.9 million net decrease in cash related to $71.7 million of cash paid for income taxes during 2017, compared with $100.2 million of cash received during 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 $149.8 million decrease in cash related to lower overall collections from customers during 2017, compared with 2016. Collections from customers decreased primarily because of unfavorable weather and the loss of sales from the transfer of customers to UMERC in 2017.

- Cash distributions provided by ATC of $38.4 million during 2016. Effective January 1, 2017, we transferred our investment in ATC to another subsidiary of WEC Energy Group. See Note 16, Investment in American Transmission Company, for more information.

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

- A $115.7 million increase in cash from lower payments for transfers of certain benefit-related liabilities to WBS during 2017, compared with 2016.

- A $56.9 million increase in cash from lower payments for operating and maintenance expenses. During 2017, our payments related to transmission, electric and natural gas distribution, and charitable projects decreased.

- A $32.5 million net increase in cash resulting from lower payments for fuel and purchased power due to the transfer of electric customers to UMERC effective January 1, 2017. This increase in cash was partially offset by higher payments for natural gas, primarily due to higher commodity prices. The average per-unit cost of natural gas sold increased 8.9% during 2017, compared with 2016.

Investing Activities

2018 Compared with 2017

Net cash used in investing activities increased $72.2 million during 2018, compared with 2017, driven by:

- Net payments of $51.0 million to affiliates during 2018, related to transfers of an enterprise resource planning system, other software, and equipment. There were no similar transfers in 2017.

- A $21.2 million decrease in the proceeds received from the sale of assets during 2018, compared with 2017. See Note 2, Dispositions, for more information.

- A $7.1 million increase in cash paid for capital expenditures during 2018, compared with 2017, which is discussed in more detail below.

2017 Compared with 2016

Net cash used in investing activities increased $131.4 million during 2017, compared with 2016, driven by:

- A $126.6 million increase in cash paid for capital expenditures during 2017, compared with 2016, which is discussed in more detail below.

- Cash of $13.1 million received during 2016 related to transfers of certain software to WBS. There were no similar transfers in 2017.

- An $8.8 million decrease in the proceeds received from the sale of assets during 2017, compared with 2016. See Note 2, Dispositions, for more information.

These increases in net cash used in investing activities were partially offset by $16.1 million of capital contributions paid to ATC during 2016. Effective January 1, 2017, we transferred our investment in ATC to another subsidiary of WEC Energy Group.

Capital Expenditures

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

(in millions)	2018	2017	2016	Change in 2018 Over 2017	Change in 2017 Over 2016
Capital expenditures	**$ 603.2**	$ 596.1	$ 469.5	$ 7.1	$ 126.6

2018 Compared with 2017

The increase in cash paid for capital expenditures during 2018, compared with 2017, was driven by upgrades to our natural gas and electric distribution systems, including main replacement projects, an information technology project created to improve our billing, call center and credit collection functions, and various other software projects.

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 during 2017, compared with 2016, was driven by upgrades to our electric and natural gas distribution systems, including main replacement projects and an advanced metering infrastructure program, as well as various projects at the OCPP.

Financing Activities

2018 Compared with 2017

Net cash used in financing activities increased $181.0 million during 2018, compared with 2017, driven by:

- A $250.0 million repayment of long-term debt during 2018.
- A $127.9 million net decrease in cash due to $76.0 million of net repayments of commercial paper during 2018, compared with $51.9 million of net borrowings of commercial paper during 2017.
- A $70.0 million increase in dividends paid to our parent during 2018, compared with 2017.
- A $47.0 million decrease in equity contributions received from our parent to balance our capital structure in 2018, compared with 2017.

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

- A $300.0 million increase in cash due to the issuance of long-term debt during 2018.
- An $18.5 million repayment to our parent during 2017 related to our former subsidiary's note payable.

2017 Compared with 2016

Net cash used in financing activities decreased $290.4 million during 2017, compared with 2016, driven by:

- A $215.0 million decrease in dividends paid to our parent during 2017 compared with 2016. During 2016, we paid special dividends to our parent to balance our capital structure.
- A $75.0 million equity contribution received from our parent to balance our capital structure in 2017.
- A $36.9 million increase in net borrowings of commercial paper during 2017, compared with 2016.

These decreases in net cash used for financing activities were partially offset by a $17.4 million increase in repayments to our parent during 2017 related to our former subsidiary's note payable, compared with 2016.

Significant Financing Activities

For more information on our financing activities, see Note 10, Short-Term Debt and Lines of Credit, and Note 11, 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, and equity contributions from our parent.

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.

We maintain a bank back-up credit facility, which provides liquidity support for our 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 10, Short-Term Debt and Lines of Credit, for more information on our credit facility.

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 11, 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 $60.6 million. We do not expect this to have any impact on our liquidity since we believe we have an adequate back-up line 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.

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 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 credit ratings on negative outlook or downgrading our credit ratings. Any such actions by credit rating agencies may make it more difficult and costly for us to issue future debt securities and certain other types of financing and could increase borrowing costs under our credit facility.

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]	$ 5,288.3	$ 372.7	$ 522.5	$ 207.5	$ 4,185.6
Capital lease obligations [3]	7,564.5	403.9	810.5	783.8	5,566.3
Operating lease obligations [4]	21.7	2.9	3.5	1.4	13.9
Energy and transportation purchase obligations [5]	10,160.6	761.9	1,385.2	1,429.0	6,584.5
Purchase orders [6]	300.4	101.8	134.9	38.9	24.8
Pension and OPEB funding obligations [7]	11.5	3.9	7.6	—	—
Total contractual obligations	$ 23,347.0	$ 1,647.1	$ 2,864.2	$ 2,460.6	$ 16,375.1

[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).

[3] Capital lease obligations for power purchase commitments and the leases with We Power.

[4] Operating lease obligations for 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 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 reflect estimated future payments related to the manufactured gas plant remediation liability of $13.2 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 19, Commitments and Contingencies, for more information about environmental liabilities.

AROs in the amount of $70.7 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 7, 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 for the next three years are as follows:

(in millions)	
2019	$ 636.7
2020	876.3
2021	979.0
Total	$ 2,492.0

The majority of spending consists of upgrading our 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.

Additionally, as part of our commitment to invest in zero-carbon generation, we plan to invest in utility scale solar. Solar generation technology has greatly improved, has become more cost-effective, and it complements our summer demand curve.

Common Stock Matters

For information related to our common stock matters, see Note 8, Common Equity.

Investments in Outside Trusts

We use outside trusts to fund our pension and certain OPEB obligations. These trusts had investments of approximately $1.2 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 $6.3 million, $8.3 million, and $8.0 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 15, 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 letters of credit that primarily support our commodity contracts. We believe that these agreements do not have, and are not reasonably likely to have, a current or future material effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources. See Note 1(o), Guarantees, Note 10, Short-Term Debt and Lines of Credit, and Note 18, Variable Interest Entities, for more information.

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

We account for our regulated operations in accordance with accounting guidance under the Regulated Operations Topic of the FASB ASC. Our rates are determined by various regulatory commissions. Our primary regulator is the PSCW. See Note 21, Regulatory Environment, for additional information regarding recent rate proceedings and orders.

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 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 $2,902.3 million, and our regulatory liabilities were $2,014.2 million.

Due to the Tax Legislation signed into law in December 2017, we remeasured our deferred taxes and recorded a tax benefit of $1,065 million. We have been returning this tax benefit to ratepayers through bill credits and reductions to other regulatory assets, which we expect to continue. See Note 12, Income Taxes, and Note 21, Regulatory Environment, for more information.

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

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

Weather

Our utility 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. A summary of actual weather information in our service territory 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 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.

Based on our 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 $1.4 million and $2.1 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 the PSCW.

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	**$ 1,019.8**	7.00%
OPEB trust funds	**$ 201.5**	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.

WEC Energy Group consults with its investment advisors on an annual basis to help it 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

Our service territories are primarily within the state of Wisconsin. As such, we are exposed to market risks in the regional Midwest economy. In addition, any economic downturn or disruption of national or international markets could adversely affect the financial condition of our customers and demand for their products, which could affect their demand for our products.

Inflation

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

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

Competitive Markets

Electric Utility Industry

The regulated energy industry continues to experience significant changes. The FERC continues to support large RTOs, which affects the structure of the wholesale market. To this end, MISO implemented the MISO Energy Markets, including the use of LMP to value electric transmission congestion and losses. Increased competition in the retail and wholesale markets, which may result from restructuring efforts, could have a significant and adverse financial impact on us.

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, and it is uncertain when, if at all, retail choice might be implemented in Wisconsin.

Natural Gas Utility Industry

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

Environmental Matters

See Note 19, 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 issued a written order in May 2018 regarding how to refund certain tax savings from the Tax Legislation to our ratepayers in Wisconsin. In addition, in May 2018, the MPSC approved a settlement with our one retail electric customer in Michigan that addresses all base rate impacts of the Tax Legislation. 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 21, Regulatory Environment, for more information.

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.

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:

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.

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 was 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 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 15, 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 through the ratemaking process.

The following table shows how a given change in certain actuarial assumptions would impact the projected benefit obligation and the reported net periodic pension cost. 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)	$ 55.5	$ 4.6
Discount rate	0.5	(49.8)	(3.6)
Rate of return on plan assets	(0.5)	N/A	5.3
Rate of return on plan assets	0.5	N/A	(5.3)

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)	$ 14.6	$ 0.7
Discount rate	0.5	(13.1)	—
Health care cost trend rate	(0.5)	(7.1)	(1.2)
Health care cost trend rate	0.5	8.2	1.4
Rate of return on plan assets	(0.5)	N/A	1.1
Rate of return on plan assets	0.5	N/A	(1.1)

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 asset assumption 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 7.00% in 2018, 2017, and 2016. The actual rate of return on pension plan assets, net of fees, was (2.91)%, 11.48%, and 6.91%, 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 15, 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 ratemaking principles followed by the 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 $2,902.3 million in regulatory assets and $2,014.2 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 $3.6 billion included accrued utility revenues of $215.6 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(l), Income Taxes, and Note 12, Income Taxes, for a discussion of accounting for income taxes.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

A. REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholder and the Board of Directors of Wisconsin Electric Power Company

Opinion on the Financial Statements

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

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 Public Company Accounting Oversight Board (United States) (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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
February 26, 2019

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

B. CONSOLIDATED INCOME STATEMENTS

Year Ended December 31 *(in millions)*	2018	2017	2016
Operating revenues	**$ 3,625.0**	$ 3,711.7	$ 3,792.8
Operating expenses			
Cost of sales	**1,262.1**	1,286.4	1,292.1
Other operation and maintenance	**1,502.4**	1,352.0	1,425.5
Depreciation and amortization	**348.1**	331.6	325.4
Property and revenue taxes	**109.9**	109.6	115.6
Total operating expenses	**3,222.5**	3,079.6	3,158.6
Operating income	**402.5**	632.1	634.2
Equity in earnings of transmission affiliate	**—**	—	55.5
Other income, net	**20.2**	13.2	4.4
Interest expense	**120.1**	117.3	117.6
Other expense	**(99.9)**	(104.1)	(57.7)
Income before income taxes	**302.6**	528.0	576.5
Income tax (benefit) expense	**(56.9)**	191.2	211.0
Net income	**359.5**	336.8	365.5
Preferred stock dividend requirements	**1.2**	1.2	1.2
Net income attributed to common shareholder	**$ 358.3**	$ 335.6	$ 364.3

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

C. CONSOLIDATED BALANCE SHEETS

At December 31 *(in millions, except share and per share amounts)*	2018	2017
Assets		
Current assets		
Cash and cash equivalents	**$ 20.2**	$ 12.3
Accounts receivable and unbilled revenues, net of reserves of $40.9 and $39.5, respectively	**472.3**	513.8
Accounts receivable from related parties	**112.4**	109.1
Materials, supplies, and inventories	**241.4**	250.7
Prepayments	**163.7**	144.3
Other	**6.3**	9.4
Current assets	**1,016.3**	1,039.6
Long-term assets		
Property, plant, and equipment, net of accumulated depreciation of $3,450.1 and $3,741.8, respectively	**9,528.9**	10,007.7
Regulatory assets	**2,902.2**	1,984.9
Other	**90.9**	89.4
Long-term assets	**12,522.0**	12,082.0
Total assets	**$ 13,538.3**	$ 13,121.6
Liabilities and Equity		
Current liabilities		
Short-term debt	**$ 134.9**	$ 210.9
Current portion of long-term debt	**250.0**	250.0
Current portion of capital lease obligations	**49.9**	42.5
Accounts payable	**248.9**	329.3
Accounts payable to related parties	**226.0**	131.5
Accrued payroll and benefits	**50.4**	53.4
Other	**116.8**	170.0
Current liabilities	**1,076.9**	1,187.6
Long-term liabilities		
Long-term debt	**2,459.6**	2,412.3
Capital lease obligations	**2,807.2**	2,823.8
Deferred income taxes	**1,298.3**	1,155.5
Regulatory liabilities	**2,002.3**	1,708.0
Pension and OPEB obligations	**118.5**	143.2
Other	**284.3**	276.9
Long-term liabilities	**8,970.2**	8,519.7
Commitments and contingencies (Note 19)		
Common shareholder's equity		
Common stock – $10 par value; 65,000,000 shares authorized; 33,289,327 shares outstanding	**332.9**	332.9
Additional paid in capital	**831.3**	802.7
Retained earnings	**2,296.6**	2,248.3
Common shareholder's equity	**3,460.8**	3,383.9
Preferred stock	**30.4**	30.4
Total liabilities and equity	**$ 13,538.3**	$ 13,121.6

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

D. CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31 *(in millions)*	2018	2017	2016
Operating activities			
Net income	**$ 359.5**	$ 336.8	$ 365.5
Reconciliation to cash provided by operating activities			
Depreciation and amortization	**348.1**	331.6	325.4
Deferred income taxes and investment tax credits, net	**(0.7)**	109.7	206.2
Contributions and payments related to pension and OPEB plans	**(6.3)**	(8.3)	(8.0)
Equity income in transmission affiliate, net of distributions	**—**	—	(17.2)
Payments for liabilities transferred to affiliates	**(10.1)**	(0.3)	(116.0)
Change in –			
Accounts receivable and unbilled revenues	**34.8**	(64.9)	(59.0)
Materials, supplies, and inventories	**9.3**	20.3	30.6
Prepaid taxes	**(28.3)**	0.5	39.4
Other current assets	**13.5**	(11.8)	9.3
Accounts payable	**13.2**	45.8	31.3
Accrued taxes	**(41.1)**	12.8	30.4
Other current liabilities	**(5.2)**	12.2	10.7
Other, net	**275.5**	(86.4)	(0.2)
Net cash provided by operating activities	**962.2**	698.0	848.4
Investing activities			
Capital expenditures	**(603.2)**	(596.1)	(469.5)
Capital contributions to transmission affiliate	**—**	—	(16.1)
Proceeds from the sale of assets	**1.7**	22.9	31.7
Proceeds from assets transferred to affiliates	**8.8**	—	13.1
Payments for assets transferred from affiliates	**(59.8)**	—	—
Other, net	**12.1**	5.0	4.0
Net cash used in investing activities	**(640.4)**	(568.2)	(436.8)
Financing activities			
Change in short-term debt	**(76.0)**	51.9	15.0
Repayment of subsidiary note to parent	**—**	(18.5)	(1.1)
Issuance of long-term debt	**300.0**	—	—
Retirement of long-term debt	**(250.0)**	—	—
Equity contribution from parent	**28.0**	75.0	—
Payment of dividends to parent	**(310.0)**	(240.0)	(455.0)
Payment of preferred stock dividends	**(1.2)**	(1.2)	(1.2)
Other, net	**(4.7)**	(0.1)	19.0
Net cash used in financing activities	**(313.9)**	(132.9)	(423.3)
Net change in cash and cash equivalents	**7.9**	(3.1)	(11.7)
Cash and cash equivalents at beginning of year	**12.3**	15.4	27.1
Cash and cash equivalents at end of year	**$ 20.2**	$ 12.3	$ 15.4

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

E. CONSOLIDATED STATEMENTS OF EQUITY

(in millions)	Wisconsin Electric Power Company Common Shareholder's Equity					
	Common Stock	Additional Paid-In Capital	Retained Earnings	Total Common Shareholder's Equity	Preferred Stock	Total Equity
Balance at December 31, 2015	$ 332.9	$ 999.7	$ 2,231.4	$ 3,564.0	$ 30.4	$ 3,594.4
Net income	—	—	365.5	365.5	—	365.5
Dividends						
Common stock	—	—	(455.0)	(455.0)	—	(455.0)
Preferred stock	—	—	(1.2)	(1.2)	—	(1.2)
Tax benefit of exercised stock options allocated from parent	—	19.3	—	19.3	—	19.3
Stock-based compensation and other	—	1.1	0.1	1.2	—	1.2
Balance at December 31, 2016	$ 332.9	$ 1,020.1	$ 2,140.8	$ 3,493.8	$ 30.4	$ 3,524.2
Net income	—	—	336.8	336.8	—	336.8
Dividends						
Common stock	—	—	(240.0)	(240.0)	—	(240.0)
Preferred stock	—	—	(1.2)	(1.2)	—	(1.2)
Cumulative effect adjustment from adoption of ASU 2016-09	—	—	11.9	11.9	—	11.9
Equity contribution from parent	—	75.0	—	75.0	—	75.0
Transfer of net assets to UMERC	—	(61.1)	—	(61.1)	—	(61.1)
Transfer of ATC ownership interest and related taxes	—	(228.6)	—	(228.6)	—	(228.6)
Settlement of a short-term note receivable between Bostco and our parent company	—	(4.8)	—	(4.8)	—	(4.8)
Stock-based compensation and other	—	2.1	—	2.1	—	2.1
Balance at December 31, 2017	$ 332.9	$ 802.7	$ 2,248.3	$ 3,383.9	$ 30.4	$ 3,414.3
Net income	**—**	**—**	**359.5**	**359.5**	**—**	**359.5**
Dividends						
Common stock	**—**	**—**	**(310.0)**	**(310.0)**	**—**	**(310.0)**
Preferred stock	**—**	**—**	**(1.2)**	**(1.2)**	**—**	**(1.2)**
Equity contribution from parent	**—**	**28.0**	**—**	**28.0**	**—**	**28.0**
Stock-based compensation and other	**—**	**0.6**	**—**	**0.6**	**—**	**0.6**
Balance at December 31, 2018	**$ 332.9**	**$ 831.3**	**$ 2,296.6**	**$ 3,460.8**	**$ 30.4**	**$ 3,491.2**

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

F. CONSOLIDATED STATEMENTS OF CAPITALIZATION

At December 31 *(in millions)*			2018	2017
Common shareholder's equity (see accompanying statement)			**3,460.8**	3,383.9
Preferred stock (Note 9)			**30.4**	30.4
Long-term debt	**Interest Rate**	**Year Due**		
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
Obligations under capital leases			**2,857.1**	2,866.3
Total			**5,592.1**	5,551.3
Unamortized debt issuance costs			**(6.0)**	(3.2)
Unamortized discount, net			**(19.4)**	(19.5)
Total long-term debt and capital lease obligations, including current portion			**5,566.7**	5,528.6
Current portion of long-term debt and capital lease obligations			**(299.9)**	(292.5)
Total long-term debt and capital lease obligations			**5,266.8**	5,236.1
Total long-term capitalization			**$ 8,758.0**	$ 8,650.4

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

G. NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Nature of Operations—We are an electric, natural gas, and steam utility company that serves electric customers in Wisconsin, an iron ore mine owned by Tilden in the Upper Peninsula of Michigan, natural gas customers in Wisconsin, and steam customers in metropolitan Milwaukee, Wisconsin. WEC Energy Group owns all of our outstanding common stock.

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 assets previously held by us, and the electric and natural gas distribution assets previously held by WPS, located in the Upper Peninsula of Michigan. The existing contract between Tilden and us will remain in place until a new power generation solution for the region is commercially operational, which is expected to occur during the second quarter of 2019.

As used in these notes, the term "financial statements" refers to the consolidated financial statements. This includes the income statements, balance sheets, statements of cash flows, statements of equity, and statements of capitalization, unless otherwise noted.

Through October 2018, we had one wholly owned subsidiary, Bostco. At December 31, 2016, Bostco had total assets of $24.4 million. In March 2017, we sold substantially all of the remaining assets of Bostco, and, in October 2018, Bostco was dissolved. See Note 2, Dispositions, for more information. The financial statements include our accounts and the accounts of our former wholly owned subsidiary. 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 residential and commercial and industrial customers, our performance obligation is bundled to consist of both the sale and the delivery of the electric commodity.

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 our tariffs, 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. We monitor the deferral of under-collected costs to ensure that it does not cause us to earn a greater ROE than authorized by the PSCW. In contrast, the rates of our Michigan retail electric customer include recovery of fuel and purchased power costs on a one-for-one basis. In addition, our Wisconsin residential tariffs 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 us 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 operations 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 for sales included in our tariffs, 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 our tariffs. 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 rates, charges, terms, and conditions of service included in our tariffs, which have been approved by the PSCW. 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.

Our tariffs include various rate mechanisms that allow us to recover or refund changes in prudently incurred costs from rate case-approved amounts. Our rates 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, our Wisconsin residential tariffs 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.

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 Operating Revenues

Alternative Revenues

Alternative revenues are created from programs authorized by regulators that allow us 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. 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.

Our only alternative revenue program relates to the wholesale electric service that we provide 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
Materials and supplies	**$ 146.1**	$ 140.7
Fossil fuel	**58.7**	74.8
Natural gas in storage	**36.6**	35.2
Total	**$ 241.4**	$ 250.7

Substantially all materials and supplies, fossil fuel, and natural gas in storage 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 PSCW and MPSC that include estimates for salvage value and removal costs. Depreciation as a percent of average depreciable utility plant was 3.18%, 2.95%, and 3.00% in 2018, 2017, and 2016, respectively.

We capitalize certain costs related to software developed or obtained for internal use and record these costs to amortization expense over the estimated useful life of the related software, which ranges from 5 to 15 years. If software is retired prior to being fully amortized, the difference is recorded as a loss on the income statement.

For assets other than our regulated assets and leased equipment, we accrue depreciation expense at straight-line rates over the estimated useful lives of the assets, or over the non-cancellable lease term for leased equipment.

Third parties reimburse us 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.

Approximately 50% of our retail jurisdictional CWIP expenditures are subject to the AFUDC calculation. Our average AFUDC retail rates were 8.45% for 2018, 2017, and 2016. Our average AFUDC wholesale rates were 3.63%, 5.94%, and 2.73% for 2018, 2017, and 2016, respectively.

We recorded the following AFUDC for the years ended December 31:

(in millions)	2018	2017	2016
AFUDC – Debt	**$ 1.5**	$ 1.2	$ 1.7
AFUDC – Equity	**$ 3.9**	$ 3.1	$ 4.2

(i) 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. 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 7, Asset Retirement Obligations, for more information.

(j) Asset Impairment—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. 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.

(k) Stock-Based Compensation—Our employees participate in the WEC Energy Group stock-based compensation plans. In accordance with the WEC Energy Group shareholder approved Omnibus Stock Incentive Plan, WEC Energy Group provides long-term incentives through its equity interests to its non-employee directors, selected 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 WEC Energy Group common stock, cash, or a combination thereof. The number of shares of WEC Energy Group common stock authorized for issuance under the plan is 34.3 million.

Stock-based compensation expense is allocated to us based on the outstanding awards held by our employees and our allocation of labor costs. 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 an $11.9 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

Our employees are granted WEC Energy Group 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 the fair market value of WEC Energy Group common stock on the grant date. Historically, all stock options have been granted with an exercise price equal to the fair market

value of WEC Energy Group 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 grant.

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

	2018	2017	2016
Stock options granted	**81,730**	80,770	92,880
Estimated weighted-average fair value per stock option	**$ 7.26**	$ 7.12	$ 4.92
Assumptions used to value the options:			
Risk-free interest rate	**1.6% – 2.5%**	0.7% – 2.5%	0.5% – 2.2%
Dividend yield	**3.5%**	3.5%	4.0%
Expected volatility	**18.0%**	19.0%	18.0%
Expected life (years)	**5.1**	6.2	5.8

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 WEC Energy Group's dividend rate at the time of the grant and historical stock prices. Expected volatility and expected life assumptions were based on WEC Energy Group's historical experience.

Restricted Shares

WEC Energy Group restricted shares granted to our employees have a three-year vesting period with one-third of the award vesting on each anniversary of the grant date. The 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 WEC Energy Group's 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. Participants may earn between 0% and 175% of the base 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 WEC Energy Group's 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 8, Common Equity, for more information on WEC Energy Group's stock-based compensation plans.

(l) 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. We are included in WEC Energy Group's consolidated Federal and state income tax returns. In accordance with our tax allocation agreement with WEC Energy Group, we are allocated income tax payments and refunds based upon our separate tax computation. See Note 12, Income Taxes, for more information.

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

(m) 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 13, Fair Value Measurements, for more information.

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

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, the PSCW allows the effects of fair value accounting to be offset to regulatory assets and liabilities.

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

Derivative accounting rules provide the option to present certain asset and liability derivative positions net on the balance sheets and to net the related cash collateral against these net derivative positions. We elected not to net these items. On our balance sheets, cash collateral provided to others is reflected in other current assets. See Note 14, Derivative Instruments, for more information.

(o) 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. As of December 31, 2018, we had $26.2 million of standby letters of credit issued by financial institutions for the benefit of third parties that extended credit to us which automatically renew each year unless proper termination notice is given. These amounts are not reflected on our balance sheets.

(p) Employee Benefits—The costs of pension and OPEB plans are expensed over the periods during which employees render service. These costs are distributed among WEC Energy Group's subsidiaries based on current employment status and actuarial calculations, as applicable. Our regulators allow recovery in rates for our net periodic benefit cost calculated under GAAP. See Note 15, Employee Benefits, for more information.

(q) 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.

(r) 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 7, Asset Retirement Obligations, for more information regarding coal combustion product landfill sites and Note 19, 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.

We 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 PSCW'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.

(s) Customer Concentrations of Credit Risk—We provide regulated electric, natural gas, and steam service to customers in Wisconsin and to Tilden located in the Upper Peninsula of Michigan. See Note 3, Related Parties, and Note 21, Regulatory Environment, for information regarding the transfer of our customers located in the Upper Peninsula of Michigan to UMERC as of January 1, 2017. 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. Our credit risk exposure is mitigated by our recovery mechanism 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—DISPOSITIONS

Utility 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.

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.

NOTE 3—RELATED PARTIES

We routinely enter into transactions with related parties, including WEC Energy Group, its other subsidiaries, ATC, and other affiliated entities.

We provide and receive services, property, and other items of value to and from our parent, WEC Energy Group, and other subsidiaries of WEC Energy Group.

Following our parent company's acquisition of Integrys on June 29, 2015, an AIA (Non-WBS AIA) went into effect. The Non-WBS AIA governed the provision and receipt of services by WEC Energy Group's subsidiaries, except that WBS continued to provide services to Integrys and its subsidiaries only under the existing WBS AIAs. WBS provided services to WEC Energy Group and the former Wisconsin Energy Corporation subsidiaries, including us, under interim WBS AIAs. The PSCW and all other relevant state commissions approved the Non-WBS AIA or granted appropriate waivers related to the Non-WBS AIA.

Services under the Non-WBS AIA were subject to various pricing methodologies. All services provided by any regulated subsidiary to another regulated subsidiary were priced at cost. All services provided by any regulated subsidiary to any nonregulated subsidiary were priced at the greater of cost or fair market value. All services provided by any nonregulated subsidiary to any regulated subsidiary were priced at the lesser of cost or fair market value. All services provided by any regulated or nonregulated subsidiary to WBS were priced at cost.

WBS provided several categories of services (including financial, human resource, and administrative services) to us pursuant to the interim WBS AIAs, which were approved, or from which we were granted appropriate waivers, by the appropriate regulators, including the PSCW. As required by FERC regulations for centralized service companies, WBS renders services at cost. The PSCW must be notified prior to making changes to the services offered under and the allocation methods specified in the interim WBS AIAs. Other modifications or amendments to the interim WBS AIAs would require PSCW approval. Recovery of allocated costs is addressed in our rate cases.

A new AIA took effect January 1, 2017. The new agreement replaced the previous agreements. The pricing methodology and services under this new agreement are substantially identical to those under the agreements that were replaced. All of the applicable state commissions approved modifications to the new AIA to incorporate WEC Energy Group's acquisition of Bluewater. See below for more information on the acquisition.

In connection with the sale of Bostco's remaining real estate holdings, Wispark, a subsidiary of WEC Energy Group, provided $7.0 million of financing to the buyer and established a corresponding note receivable. Bostco had a $7.0 million related party receivable from Wispark that was paid in April 2017. See Note 2, Dispositions, for more information on the real estate sale.

On January 1, 2017, based upon input we received from the PSCW, we transferred our $415.4 million investment in ATC, and the related receivable for distributions approved and recorded in December 2016, to another subsidiary of WEC Energy Group. In addition, during 2017 we transferred $186.8 million of related deferred income tax liabilities. These transactions were non-cash equity transfers recorded to additional paid in capital between entities under common control, and therefore, did not result in the recognition of a gain or loss.

We pay ATC for 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. Services are billed to and from ATC under agreements approved by the PSCW, at each of our fully allocated costs.

Our balance sheets included the following receivables and payables related to transactions entered into with ATC:

(in millions)	2018	2017
Accounts receivable		
Services provided to ATC	**$ 2.2**	$ 0.8
Accounts payable		
Services received from ATC	**19.4**	22.2

The following table shows activity associated with our related party transactions for the years ended December 31:

(in millions)	2018	2017	2016
Lease agreements			
Lease payments to We Power [1]	**$ 373.7**	$ 420.5	$ 412.2
CWIP billed to We Power	**39.5**	57.3	37.9
Transactions with WBS [2]			
Billings to WBS	**61.5**	255.7 [3]	213.8 [3]
Billings from WBS [4]	**243.4**	215.4	310.6
Transactions with WPS			
Natural gas purchases from WPS	**1.9**	1.6	1.9
Billings to WPS [2]	**17.8** [3]	28.2	9.0
Billings from WPS [2]	**10.9**	4.5	4.2
Transactions with WG			
Natural gas purchases from WG	**5.3**	5.3	5.3
Billings to WG [2]	**59.0** [3]	64.0	60.6
Billings from WG [2]	**32.6**	23.1	21.5
Transactions with UMERC [5]			
Electric sales to UMERC	**29.6**	30.8	—
Billings to UMERC [2]	**15.8** [3]	125.5	—
Transactions with Bluewater [6]			
Storage service fees	**15.0**	2.7	—
Transactions with ATC			
Charges to ATC for services and construction	**13.9**	10.9	10.0
Charges from ATC for network transmission services	**232.0**	241.4	247.8
Refund from ATC related to a FERC audit	**15.4**	—	—
Refund from ATC per FERC ROE order	**—**	19.4	—

[1] We make lease payments to We Power, another subsidiary of WEC Energy Group, for PWGS Units 1 and 2 and ERGS Units 1 and 2. Lease payments were reduced in 2018 as a result of tax savings related to the Tax Legislation.

[2] Includes amounts billed for services, pass through costs, and other items in accordance with the approved AIAs.

[3] Includes $8.8 million for the transfer of certain software assets to affiliates for the year ended December 31, 2018, and $13.1 million for the transfer of certain software assets to WBS for the year ended December 31, 2016. Also includes $1.2 million for the transfer of certain benefit-related liabilities from WBS for the year ended December 31, 2017.

(4) For the years ended December 31, 2018, 2017, and 2016, includes $10.0 million, $1.5 million, and $116.0 million, respectively, for the transfer of certain benefit-related liabilities to WBS. Also includes $59.8 million for the transfer of certain software assets from WBS for the year ended December 31, 2018.

(5) UMERC became operational effective January 1, 2017. See below for more information.

(6) WEC Energy Group's acquisition of Bluewater was completed on June 30, 2017. See below for more information.

Parent Company's Acquisition of Natural Gas Storage Facilities in Michigan

In June 2017, our parent company completed its acquisition of Bluewater for $226.0 million. Bluewater owns natural gas storage facilities in Michigan that provide a portion of the current storage needs for our natural gas utility operations. In September 2017, we entered into a long-term service agreement with a wholly owned subsidiary of Bluewater to take a portion of the storage, which was then approved by the PSCW in November 2017. See Note 21, Regulatory Environment, for more information.

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. UMERC, a subsidiary of WEC Energy Group, became operational effective January 1, 2017, and we transferred customers and property, plant, and equipment as of that date. See Note 21, Regulatory Environment, for more information. We transferred approximately 27,500 retail electric customers and 50 electric distribution-only customers to UMERC, along with approximately 2,500 miles of electric distribution lines. We also transferred related electric distribution substations in the Upper Peninsula of Michigan and all property rights for the distribution assets to UMERC. The book value of net assets, including the related deferred income tax liabilities, transferred to UMERC from us in 2017, was $61.1 million. This transaction was a non-cash equity transfer recorded to additional paid in capital between entities under common control, and therefore, did not result in the recognition of a gain or loss. UMERC currently meets its market obligations through power purchase agreements with us and WPS.

NOTE 4—OPERATING REVENUES

Disaggregation of Operating Revenues

The following tables present our operating revenues disaggregated by revenue source. We only have revenues associated with our utility segment. We do not have any revenues associated with our other segment. 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 utility segment, 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.

	Wisconsin Electric Power Company Consolidated
(in millions)	**Year ended December 31, 2018**
Electric utility	**$ 3,212.7**
Natural gas utility	**405.1**
Total revenues from contracts with customers	**3,617.8**
Other operating revenues	**7.2**
Total operating revenues	**$ 3,625.0**

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	$ 1,220.8
Small commercial and industrial	1,020.0
Large commercial and industrial	656.6
Other	20.7
Total retail revenues	2,918.1
Wholesale	108.5
Resale	153.7
Steam	24.1
Other utility revenues	8.3
Total electric utility operating revenues	$ 3,212.7

Natural Gas Utility Operating Revenues

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

(in millions)	Natural Gas Utility Operating Revenues Year ended December 31, 2018
Residential	$ 264.3
Commercial and industrial	126.3
Total retail revenues	390.6
Transport	13.4
Other utility revenues	1.1
Total natural gas utility operating revenues	$ 405.1

Other Operating Revenues

Other operating revenues consist primarily of the following:

(in millions)	Year ended December 31, 2018
Late payment charges	$ 8.2
Leases	2.9
Alternative revenues *	(3.9)
Total other operating revenues	$ 7.2

* 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 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]			
Capital leases	**$ 869.3**	$ 801.3	11
Plant retirements	**754.1**	6.6	6
Pension and OPEB costs [3]	**490.6**	484.4	15
Income tax related items [4]	**317.9**	—	12
SSR	**316.7**	298.9	21
Electric transmission costs	**57.8**	220.7	21
We Power generation [5]	**43.0**	71.3	
AROs	**28.7**	41.4	7
Other, net	**24.2**	60.3	
Total regulatory assets	**$ 2,902.3**	$ 1,984.9	
Balance Sheet Presentation			
Current assets	**$ 0.1**	$ —	
Regulatory assets	**2,902.2**	1,984.9	
Total regulatory assets	**$ 2,902.3**	$ 1,984.9	

(1) Based on prior and current rate treatment, we believe it is probable that we will continue to recover from customers the regulatory assets in this table.

(2) As of December 31, 2018, we had $10.9 million of regulatory assets not earning a return, $98.7 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 relate to certain environmental remediation costs, the recovery of which depends on the timing of the actual expenditures. 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) For information on the flow through of tax repairs and the regulatory treatment of the impacts of the Tax Legislation, see Note 21, Regulatory Environment.

(5) Represents amounts recoverable from customers related to our costs of the generating units leased from We Power, including subsequent capital additions. See Note 11, Long-Term Debt and Capital Lease Obligations, for information on the Tax Legislation impacts on the lease payments.

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]	**$ 1,024.8**	$ 849.1	12
Removal costs [2]	**748.1**	730.0	
Mines deferral [3]	**120.8**	95.1	
Pension and OPEB costs [4]	**74.7**	10.0	15
Uncollectible expense [5]	**16.4**	6.4	1(d)
Energy efficiency programs [6]	**13.5**	11.1	
Other, net	**15.9**	19.4	
Total regulatory liabilities	**$ 2,014.2**	$ 1,721.1	
Balance Sheet Presentation			
Current liabilities	**$ 11.9**	$ 13.1	
Regulatory liabilities	**2,002.3**	1,708.0	
Total regulatory liabilities	**$ 2,014.2**	$ 1,721.1	

(1) For information on the regulatory treatment of the impacts of the Tax Legislation, see Note 21, 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) 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.

(4) 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.

(5) Represents amounts refundable to customers related to our uncollectible expense tracking mechanism. This mechanism allows us to recover or refund the difference between actual uncollectible write-offs and the amounts recovered in rates.

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

NOTE 6—PROPERTY, PLANT, AND EQUIPMENT

Property, plant, and equipment consisted of the following utility and non-utility and other assets at December 31:

(in millions)	2018	2017
Electric – generation	**$ 3,560.0**	$ 3,447.7
Electric – distribution	**4,837.9**	4,600.2
Natural gas – distribution, storage, and transmission	**1,269.6**	1,166.8
Property, plant, and equipment to be retired	**174.8**	872.7
Other	**801.8**	656.0
Less: Accumulated depreciation	**3,239.4**	2,970.3
Net	**7,404.7**	7,773.1
CWIP	**124.7**	159.5
Net utility property, plant, and equipment	**7,529.4**	7,932.6
Property under capital leases	**3,043.5**	3,009.1
Less: Accumulated amortization	**1,055.6**	945.9
Net leased facilities	**1,987.9**	2,063.2
Non-utility and other property, plant, and equipment	**11.6**	11.9
Total property, plant, and equipment	**$ 9,528.9**	$ 10,007.7

Utility 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 $25.8 million was recorded in other current liabilities related to these plant retirements.

(in millions)	
Severance liability at December 31, 2017	$ 25.8
Severance payments	**(9.9)**
Other	**(3.0)**
Total severance liability at December 31, 2018	**$ 12.9**

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 continue 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 have 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 our 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 19, 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 continue 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 our anticipated 2019 Wisconsin rate case, and also expect that the retirement will be addressed by the MPSC. See Note 21, Regulatory Environment, for more information.

NOTE 7—ASSET RETIREMENT OBLIGATIONS

We have recorded AROs primarily for asbestos abatement at certain generation and substation facilities, the removal and dismantlement of biomass and hydro generation facilities, and the closure of fly-ash landfills at our generation facilities. We establish regulatory assets and liabilities 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. 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	**$ 68.3**	$ 61.5	$ 58.7
Accretion	**3.3**	3.2	3.0
Additions and revisions to estimated cash flows	**1.0**	5.5	—
Liabilities settled	**(1.9)**	(1.9)	(0.2)
Balance as of December 31	**$ 70.7**	$ 68.3	$ 61.5

NOTE 8—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	**$ 2.0**	$ 1.3	$ 1.8
Restricted stock	**3.0**	0.8	1.8
Performance units	**9.6**	9.9	3.9
Stock-based compensation expense	**$ 14.6**	$ 12.0	$ 7.5
Related tax benefit	**$ 4.0**	$ 4.8	$ 3.0

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

Stock Options

The following is a summary of our employees' WEC Energy Group 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	1,196,147	$ 37.29		
Granted	**81,730**	**$ 66.02**		
Exercised	**(340,563)**	**$ 29.45**		
Transferred	**(238,500)**	**$ 39.71**		
Outstanding as of December 31, 2018	**698,814**	**$ 43.64**	**5.0**	**$ 17.9**
Exercisable as of December 31, 2018	**538,764**	**$ 39.30**	**4.1**	**$ 16.1**

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 WEC Energy Group's 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 $12.9 million, $11.2 million, and $14.1 million, respectively. Cash received by WEC Energy Group from exercises of its options by our employees was $10.0 million, $7.7 million, and $12.1 million during the years ended December 31, 2018, 2017, and 2016, respectively. The actual tax benefit from option exercises for the same periods was approximately $2.7 million, $4.5 million, and $5.6 million, respectively.

As of December 31, 2018, we expected to recognize approximately $1.0 million of unrecognized compensation cost related to unvested and outstanding WEC Energy Group stock options over the next 1.7 years on a weighted-average basis.

During the first quarter of 2019, the Compensation Committee awarded 59,404 non-qualified WEC Energy Group stock options with an 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 is a summary of our employees' WEC Energy Group restricted stock activity during 2018:

Restricted Shares	Number of Shares	Weighted-Average Grant Date Fair Value
Outstanding and unvested as of January 1, 2018	15,283	$ 54.96
Granted	**7,518**	**$ 64.99**
Released	**(5,380)**	**$ 54.58**
Transferred	**(5,823)**	**$ 57.17**
Forfeited	**(1,747)**	**$ 60.50**
Outstanding and unvested as of December 31, 2018	**9,851**	**$ 60.53**

The intrinsic value of WEC Energy Group restricted stock held by our employees that was released was $0.4 million, $0.5 million, and $0.4 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 $0.1 million, $0.2 million, and $0.2 million, respectively.

As of December 31, 2018, we expected to recognize approximately $1.3 million of unrecognized compensation cost related to unvested and outstanding WEC Energy Group restricted stock over the next 1.6 years on a weighted-average basis.

During the first quarter of 2019, the Compensation Committee awarded 5,181 WEC Energy Group restricted shares to our 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 32,650; 34,765; and 35,700 WEC Energy Group performance units, respectively, to our officers and other key employees under the WEC Energy Group Performance Unit Plan.

Performance units with an intrinsic value of $2.0 million, $1.4 million, and $3.4 million were settled during 2018, 2017, and 2016, respectively. The actual tax benefit from the distribution of performance units for the same years was approximately $0.4 million, $0.4 million, and $0.5 million, respectively.

At December 31, 2018, our employees held 68,583 of outstanding WEC Energy Group performance units, including dividend equivalents. A liability of $4.3 million was recorded on our balance sheet at December 31, 2018 related to these outstanding units. As of December 31, 2018, we expected to recognize approximately $8.6 million of unrecognized compensation cost related to unvested and outstanding WEC Energy Group performance units over the next 1.3 years on a weighted-average basis.

During the first quarter of 2019, performance units held by our employees with an intrinsic value of $2.2 million were settled. The actual tax benefit from the distribution of these awards was $0.5 million. In January 2019, the Compensation Committee also awarded 22,452 WEC Energy Group performance units to our officers and other key employees under its normal schedule of awarding long-term incentive compensation.

Restrictions

Various financing arrangements and regulatory requirements impose certain restrictions on our ability to transfer funds to WEC Energy Group in the form of cash dividends, loans, or advances. In addition, Wisconsin law prohibits us from making loans to or guaranteeing obligations of WEC Energy Group or its subsidiaries.

In accordance with our most recent rate order, we may not pay common dividends above the test year forecasted amount reflected in our rate case, if it would cause our average common equity ratio, on a financial basis, to fall below our authorized level of 51%. A return of capital in excess of the test year amount can be paid by us at the end of the year provided that our average common equity ratio does not fall below the authorized level.

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

See Note 10, Short-Term Debt and Lines of Credit, for discussion of certain financial covenants related to short-term debt obligations.

As of December 31, 2018, our restricted retained earnings totaled $2.2 billion.

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

NOTE 9—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
$100 par value, Six Per Cent. Preferred Stock	**45,000**	**44,498**	**—**	**$ 4.4**
$100 par value, Serial Preferred Stock	**2,286,500**			
3.60% Series		**260,000**	**$ 101**	**26.0**
$25 par value, Serial Preferred Stock	**5,000,000**	**—**	**—**	**—**
Total				**$ 30.4**

NOTE 10—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	**$ 134.9**	$ 210.9
Average interest rate on amounts outstanding at December 31	**2.96%**	1.81%

Our average amount of commercial paper borrowings based on daily outstanding balances during 2018 was $132.6 million, with a weighted-average interest rate during the period of 2.26%.

We have entered into a bank back-up credit facility to maintain short-term credit liquidity which, among other terms, requires us to maintain, subject to certain exclusions, a total funded debt to capitalization ratio of 65% or less. As of December 31, 2018, we were in compliance with this ratio.

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

(in millions)	Maturity	2018
Revolving credit facility	October 2022	**$ 500.0**
Less:		
Letters of credit issued inside credit facility		**$ 1.2**
Commercial paper outstanding		**134.9**
Available capacity under existing agreement		**$ 363.9**

This facility has a renewal provision for two one-year extensions, subject to lender approval.

Our bank back-up credit facility contains customary covenants, including certain limitations on our ability to sell assets. The credit facility also contains 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.

NOTE 11—LONG-TERM DEBT AND CAPITAL LEASE OBLIGATIONS

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

Debentures and Notes

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 our 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 us.

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

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)		
2019	$	250.0
2020		—
2021		300.0
2022		—
2023		—
Thereafter		2,185.0
Total	$	2,735.0

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

Obligations Under Capital Leases

We are the obligor under a power purchase contract with an unaffiliated third party and we lease power plants from We Power. Under capital lease accounting, we have recorded the leased plants and corresponding obligations under the capital leases on our balance sheets. We treat these agreements as operating leases for rate-making purposes. We record our minimum lease payments under the power purchase contract as purchased power expense on our income statements. We record the lease payments under our leases with We Power as rent expense in other operation and maintenance in our income statements. 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. See Note 5, Regulatory Assets and Liabilities, for more information on our plant related capital leases.

Power Purchase Commitment

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 our option and with proper notice, renew for another 10 years or purchase the generating facility at fair market 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 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. 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.

Port Washington Generating Station

We are leasing PWGS 1 and PWGS 2, two 545 MW natural gas-fired generation units which were placed in service in July 2005 and May 2008, respectively, from We Power under PSCW approved leases. The leased units and corresponding obligations for the units have been recorded at the estimated fair value of $736.9 million. We are amortizing the leased units on a straight-line basis over the original 25-year term of the leases. The lease payments are expected to be recovered through our rates, as supported by the 2001 leased generation law. Due to the timing and the amounts of the minimum lease payments, we expect the regulatory asset to increase to approximately $129.2 million in the year 2021 for PWGS 1 and to approximately $125.9 million in the year 2023 for PWGS 2, at which time the regulatory assets will be reduced to zero over the remaining lives of the contracts. The total obligation under the capital leases for the units was $634.5 million as of December 31, 2018, and will decrease to zero over the remaining lives of the contracts.

When the PWGS 1 and PWGS 2 contracts expire in 2030 and 2033, respectively, we may, at our option and with proper notice, choose to renew one or both contracts for up to three consecutive renewal terms (each renewal term would approximate 80% of the then remaining economic useful life of the respective generation unit), purchase one or both generating facilities at fair market value, or allow the contracts to expire.

Elm Road Generating Station

We are leasing ER 1, ER 2, and the common facilities, which are also utilized by our OC 5 through OC 8, from We Power under PSCW approved leases. We are amortizing the leased units on a straight-line basis over the 30-year term of the leases. ER 1 and ER 2 were placed in service in February 2010 and January 2011, respectively. The leased units and corresponding capital lease obligations have been recorded at the estimated fair value of $2,166.3 million. The lease payments are expected to be recovered through our rates, as supported by the 2001 leased generation law. Due to the timing and the amounts of the minimum lease payments, we expect the regulatory asset to increase to approximately $521.8 million in the year 2028 for ER 1 and to approximately $427.9 million in the year 2029 for ER 2, at which time the regulatory assets will be reduced to zero over the remaining lives of the contracts. The total obligation under the capital leases was $2,199.3 million as of December 31, 2018, and will decrease to zero over the remaining lives of the contracts.

When the ER 1 and ER 2 contracts expire in 2040 and 2041, respectively, we may, at our option and with proper notice, choose to renew one or both contracts for up to three consecutive renewal terms (each renewal term would approximate 80% of the then remaining economic useful life of the respective generation unit), purchase one or both generating facilities at fair market value, or allow the contracts to expire.

We paid the following lease payments during 2018, 2017, and 2016:

(in millions)	2018	2017	2016
Long-term power purchase commitment	**$ 7.7**	$ 7.2	$ 37.6
PWGS	**76.6**	85.0	82.4
ERGS	**297.1**	335.5	329.8
Total	**$ 381.4**	$ 427.7	$ 449.8

The rates charged to our customers related to the We Power leases have remained level for each of the three years ended December 31, 2018, 2017, and 2016, at $398.6 million. Because this is also the amount that was charged to operating and maintenance expense during these years, the lease payments made to We Power over this three-year period did not match the amounts we recorded as lease expense. As disclosed in the table above, lease payments related to the PWGS and ERGS leases were $373.7 million, $420.5 million, and $412.2 million in 2018, 2017, and 2016, respectively. As a result of the Tax Legislation, the lease payments were recalculated and decreased by approximately $50 million in 2018, resulting in lower lease payments when compared to lease expense recorded in 2018. Partially offsetting the lower lease payments made in 2018, and also the driving factor behind the higher lease payments in 2017 and 2016, compared to lease expense, were capital additions placed in service or that are in process since our last rate case. These capital additions are factored into our bill from We Power, but have not yet been factored into the rates we are collecting from customers. The difference between the payments we have made to We Power and the amounts collected in rates and recorded as lease expense is not expected to impact earnings as we are allowed to record the difference as an increase or reduction to the We Power generation regulatory asset until our next rate case. See Note 5, Regulatory Assets and Liabilities, for more information on the regulatory asset related to the We Power leases, and also Note 12, Income Taxes, and Note 21, Regulatory Environment, for more information on the Tax Legislation and our rates.

The following table summarizes our capitalized leased facilities as of December 31:

(in millions)	2018	2017
Long-term power purchase commitment		
Under capital lease	**$ 140.3**	$ 140.3
Accumulated amortization	**(120.9)**	(115.2)
Total long-term power purchase commitment	**19.4**	25.1
PWGS		
Under capital lease	**736.9**	727.4
Accumulated amortization	**(335.9)**	(305.1)
Total PWGS	**401.0**	422.3
ERGS		
Under capital lease	**2,166.3**	2,141.4
Accumulated amortization	**(598.8)**	(525.6)
Total ERGS	**1,567.5**	1,615.8
Total leased facilities	**$ 1,987.9**	$ 2,063.2

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

(in millions)	Power Purchase Commitment	PWGS	ERGS	Total
2019	$ 15.5	$ 97.6	$ 290.8	$ 403.9
2020	16.4	97.6	290.8	404.8
2021	17.2	97.6	290.8	405.6
2022	7.6	97.6	290.6	395.8
2023	—	97.6	290.5	388.1
Thereafter	—	773.5	4,792.8	5,566.3
Total minimum lease payments	56.7	1,261.5	6,246.3	7,564.5
Less: Estimated executory costs	(26.1)	—	—	(26.1)
Net minimum lease payments	30.6	1,261.5	6,246.3	7,538.4
Less: Interest	(7.3)	(627.0)	(4,047.0)	(4,681.3)
Present value of minimum lease payments	23.3	634.5	2,199.3	2,857.1
Less: Due currently	(4.9)	(22.3)	(22.7)	(49.9)
Long-term obligations under capital lease	$ 18.4	$ 612.2	$ 2,176.6	$ 2,807.2

NOTE 12—INCOME TAXES

Income Tax Expense

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

(in millions)	2018	2017	2016
Current tax (benefit) expense	**$ (56.2)**	$ 81.5	$ 4.8
Deferred income taxes, net	**0.1**	110.6	207.3
Investment tax credit, net	**(0.8)**	(0.9)	(1.1)
Total income tax (benefit) expense	**$ (56.9)**	$ 191.2	$ 211.0

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		2016	
(in millions)	Amount	Effective Tax Rate	Amount	Effective Tax Rate	Amount	Effective Tax Rate
Expected tax at statutory federal tax rates	**$ 63.3**	**21.0 %**	$ 184.4	35.0 %	$ 201.4	35.0 %
State income taxes net of federal tax benefit	**19.6**	**6.5 %**	27.9	5.3 %	31.8	5.5 %
Tax repairs *	**(120.7)**	**(39.9)%**	—	— %	—	— %
Federal excess amortization	**(15.5)**	**(5.1)%**	—	— %	—	— %
Production tax credits	**(9.4)**	**(3.1)%**	(17.6)	(3.3)%	(16.5)	(2.8)%
Investment tax credit restored	**(0.8)**	**(0.3)%**	(0.9)	(0.2)%	(1.1)	(0.2)%
AFUDC – Equity	**(0.8)**	**(0.3)%**	(1.1)	(0.2)%	(1.5)	(0.3)%
Domestic production activities deferral (deduction)	**6.1**	**2.0 %**	(7.8)	(1.5)%	(7.8)	(1.4)%
Other, net	**1.3**	**0.4 %**	6.3	1.1 %	4.7	0.8 %
Total income tax (benefit) expense	**$ (56.9)**	**(18.8)%**	$ 191.2	36.2 %	$ 211.0	36.6 %

* In accordance with a settlement agreement with the PSCW, we will flow through the tax benefit of our 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 21, Regulatory Environment, for more information about the impact of the Tax Legislation and the Wisconsin rate settlement.

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 approximately $1,065 million. Accordingly, this amount was recorded as both an increase to regulatory liabilities as well as a decrease to certain existing regulatory assets as of December 31, 2017.

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, analyzed the impact on Alternative Minimum Tax Credit carryforwards, 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	**$ 203.0**	$ 240.1
Deferred revenues	**129.3**	128.8
Future tax benefits	**15.9**	133.1
Employee benefits and compensation	**—**	50.2
Other	**156.6**	82.4
Total deferred tax assets	**$ 504.8**	$ 634.6
Deferred tax liabilities		
Property-related	**$ 1,365.9**	$ 1,487.0
Deferred costs – Pleasant Prairie	**176.0**	—
Deferred costs – SSR	**110.7**	81.4
Employee benefits and compensation	**55.9**	117.4
Deferred transmission costs	**55.4**	60.1
Other	**39.2**	44.2
Total deferred tax liabilities	**1,803.1**	1,790.1
Deferred tax liability, net	**$ 1,298.3**	$ 1,155.5

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

At December 31, 2018, we had $11.6 million of tax credit carryforwards resulting in deferred tax assets of $11.6 million. Tax credit carryforwards begin to expire in 2038. We expect to have future taxable income sufficient to utilize these deferred tax assets. At December 31, 2017, we had $4.0 million and $125.6 million of federal charitable contribution and tax credit carryforwards resulting in deferred tax assets of $0.8 million and $125.6 million, respectively. At December 31, 2018, we had $68.7 million of state net operating losses resulting in deferred tax assets of $4.3 million. These state net operating loss carryforwards begin to expire in 2035. We expect to have future taxable income sufficient to utilize these deferred tax assets. At December 31, 2017, we had $74.7 million and $31.9 million of state net operating loss and state charitable contribution carryforwards resulting in deferred tax assets of $4.7 million and $2.0 million, respectively.

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	**$ —**	$ 5.1
Reductions for tax positions of prior years	**—**	(5.1)
Balance as of December 31	**$ —**	$ —

We do not expect any unrecognized tax benefits to affect our effective tax rate in periods after December 31, 2018.

For the years ended December 31, 2018, 2017, and 2016, we recognized no interest, $0.7 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 years ended December 31, 2018 and 2017, we had no interest accrued and no penalties accrued related to unrecognized tax benefits on our balance sheets.

We do not anticipate any significant increases in the total amount of unrecognized tax benefits within the next 12 months.

Our primary tax jurisdictions include Federal and the state of Wisconsin. With a few exceptions we are no longer subject to Federal income tax examinations by the IRS for years prior to 2015. As of December 31, 2018, we were subject to examination by the Wisconsin taxing authority for tax years 2014 through 2018.

NOTE 13—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	**$ 0.7**	**$ —**	**$ —**	**$ 0.7**
FTRs	**—**	**—**	**4.4**	**4.4**
Total derivative assets	**$ 0.7**	**$ —**	**$ 4.4**	**$ 5.1**
Derivative liabilities				
Natural gas contracts	**$ 1.2**	**$ —**	**$ —**	**$ 1.2**
Coal contracts	**—**	**0.1**	**—**	**0.1**
Total derivative liabilities	**$ 1.2**	**$ 0.1**	**$ —**	**$ 1.3**

	December 31, 2017			
(in millions)	Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	$ 0.5	$ 0.1	$ —	$ 0.6
Petroleum products contracts	0.9	—	—	0.9
FTRs	—	—	2.4	2.4
Coal contracts	—	0.7	—	0.7
Total derivative assets	$ 1.4	$ 0.8	$ 2.4	$ 4.6
Derivative liabilities				
Natural gas contracts	$ 2.0	$ 0.1	$ —	$ 2.1
Coal contracts	—	0.3	—	0.3
Total derivative liabilities	$ 2.0	$ 0.4	$ —	$ 2.4

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

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

(in millions)	2018	2017	2016
Balance at the beginning of the period	**$ 2.4**	$ 3.1	$ 1.6
Purchases	**9.4**	6.9	8.1
Settlements	**(7.4)**	(7.6)	(6.6)
Balance at the end of the period	**$ 4.4**	$ 2.4	$ 3.1

Fair Value of Financial Instruments

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

	December 31, 2018		December 31, 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	**2,709.6**	**2,881.6**	2,662.3	2,976.3

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

NOTE 14—DERIVATIVE INSTRUMENTS

The following table shows our derivative assets and derivative liabilities, none of which are designated as hedging instruments.

	December 31, 2018		December 31, 2017	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Other current				
Natural gas contracts	**$ 0.7**	**$ 1.2**	$ 0.6	$ 1.9
Petroleum products contracts	**—**	**—**	0.9	—
FTRs	**4.4**	**—**	2.4	—
Coal contracts	**—**	**0.1**	0.6	0.1
Total other current	**$ 5.1**	**$ 1.3**	$ 4.5	$ 2.0
Other long-term				
Natural gas contracts	**$ —**	**$ —**	$ —	$ 0.2
Coal contracts	**—**	**—**	0.1	0.2
Total other long-term	**$ —**	**$ —**	$ 0.1	$ 0.4
Total	**$ 5.1**	**$ 1.3**	$ 4.6	$ 2.4

Realized gains (losses) on derivatives are primarily recorded in cost of sales on the income statements. Our estimated notional sales volumes and realized gains (losses) were as follows:

	December 31, 2018		December 31, 2017		December 31, 2016	
(in millions)	Volume	Gains	Volume	Gains (Losses)	Volume	Gains (Losses)
Natural gas contracts	53.4 Dth	**$ 9.7**	26.9 Dth	$ (1.0)	35.3 Dth	$ (12.3)
Petroleum products contracts	4.2 gallons	**1.2**	16.7 gallons	(1.4)	10.3 gallons	(2.6)
FTRs	21.2 MWh	**3.4**	27.1 MWh	7.6	25.3 MWh	7.3
Total		**$ 14.3**		$ 5.2		$ (7.6)

At December 31, 2018 and 2017, we had posted cash collateral of $1.1 million and $4.9 million, respectively, in our margin accounts.

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	**$ 5.1**	**$ 1.3**	$ 4.6	$ 2.4
Gross amount not offset on the balance sheet	**(0.6)**	**(1.3)** *	(1.3)	(2.0) *
Net amount	**$ 4.5**	**$ —**	$ 3.3	$ 0.4

* Includes cash collateral posted of $0.7 million at both December 31, 2018 and 2017.

NOTE 15—EMPLOYEE BENEFITS

Pension and Other Postretirement Employee Benefits

We participate in WEC Energy Group's defined benefit pension plans and OPEB plans that cover substantially all of our employees. We are responsible for our share of the plan assets and obligations. The benefits for a portion of these plans are funded through irrevocable trusts, as allowed for income tax purposes. Our balance sheets reflect only the liabilities associated with our past and current employees and our share of the plan assets and obligations. 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, employees who started with us 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

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.

We use a year-end measurement date to measure the funded status of all of the 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 the pension and OPEB plans qualify as a regulatory asset.

The following tables provide a reconciliation of the changes in our share of the 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	**$ 1,193.9**	$ 1,177.0	**$ 303.5**	$ 298.5
Service cost	**13.2**	12.2	**6.9**	7.0
Interest cost	**42.3**	47.0	**11.1**	12.1
Participant contributions	**—**	—	**7.6**	5.7
Plan amendments	**—**	—	**—**	(6.8)
Net transfer to/from affiliates	**(4.5)** [1]	(13.4) [2]	**—**	(3.3) [2]
Actuarial loss (gain)	**(62.7)**	53.1	**(86.2)**	5.1
Benefit payments	**(82.8)**	(82.0)	**(22.8)**	(16.5)
Federal subsidy on benefits paid	**N/A**	N/A	**0.9**	1.7
Transfer	**—**	—	**6.7** [3]	**—**
Obligation at December 31	**$ 1,099.4**	$ 1,193.9	**$ 227.7**	$ 303.5
Change in fair value of plan assets				
Fair value at January 1	**$ 1,134.1**	$ 1,102.8	**$ 220.1**	$ 205.1
Actual return on plan assets	**(31.0)**	121.9	**(5.7)**	25.9
Employer contributions	**4.0**	5.1	**2.3**	3.2
Participant contributions	**—**	—	**7.6**	5.7
Net transfer to/from affiliates	**(4.5)** [1]	(13.7) [2]	**—**	(3.3) [2]
Benefit payments	**(82.8)**	(82.0)	**(22.8)**	(16.5)
Fair value at December 31	**$ 1,019.8**	$ 1,134.1	**$ 201.5**	$ 220.1
Funded status at December 31	**$ (79.6)**	$ (59.8)	**$ (26.2)**	$ (83.4)

[1] Benefit obligations and plan assets were moved along with our employees who were transferred to/from affiliated entities. See Note 3, Related Parties, for more information.

[2] Benefit obligations and plan assets were moved along with our employees who were transferred to/from affiliated entities, primarily a result of our customer service employees being transferred to WBS.

[3] Represents a premium medical account that was transferred into the OPEB benefit obligation.

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	**$ 12.7**	$ —	**$ —**	$ —
Pension and OPEB obligations	**92.3**	59.8	**26.2**	83.4
Total net liabilities	**$ (79.6)**	$ (59.8)	**$ (26.2)**	$ (83.4)

The accumulated benefit obligation for all defined benefit pension plans was $1,097.9 million and $1,192.4 million as of December 31, 2018 and 2017, respectively.

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

(in millions)	2018	2017
Projected benefit obligation	**$ 997.0**	$ 1,193.9
Accumulated benefit obligation	**995.5**	1,192.4
Fair value of plan assets	**904.7**	1,134.1

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
Net regulatory assets (liabilities)				
Net actuarial loss (gain)	**$ 491.0**	$ 485.4	**$ (66.6)**	$ (1.6)
Prior service credits	**(1.8)**	(1.0)	**(6.1)**	(8.4)
Total	**$ 489.2**	$ 484.4	**$ (72.7)**	$ (10.0)

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)	$ 28.7	$ (1.6)
Prior service costs (credits)	0.4	(1.9)
Total 2019 – estimated amortization	$ 29.1	$ (3.5)

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	**$ 13.2**	$ 12.2	$ 10.5	**$ 6.9**	$ 7.0	$ 7.3
Interest cost	**42.3**	47.0	49.7	**11.1**	12.1	13.2
Expected return on plan assets	**(75.2)**	(76.6)	(77.7)	**(15.5)**	(14.7)	(14.0)
Plan settlement	**—**	4.1	—	**—**	—	—
Amortization of prior service cost (credit)	**0.8**	1.1	1.6	**(2.2)**	(1.4)	(1.1)
Amortization of net actuarial loss	**38.0**	35.4	32.4	**—**	—	1.0
Net periodic benefit cost	**$ 19.1**	$ 23.2	$ 16.5	**$ 0.3**	$ 3.0	$ 6.4

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	$ 1,358.5	$ (6.5)	$ 1,352.0	$ 1,430.2	$ (4.7)	$ 1,425.5
Other expense						
Other income, net	19.7	(6.5)	13.2	9.1	(4.7)	4.4

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%**	3.65%	**4.30%**	3.65%
Rate of compensation increase	**3.40%**	3.20%	**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	**6.12%**	6.18%
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	**3.65%**	4.12%	4.45%
Expected return on plan assets	**7.00%**	7.00%	7.00%
Rate of compensation increase	**3.40%**	3.20%	3.50%

	OPEB Costs		
	2018	2017	2016
Discount rate	**3.65%**	4.10%	4.45%
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)	**6.18%**	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

WEC Energy Group consults with its investment advisors on an annual basis to help 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 asset assumption is 7.00% for the pension plan and 7.25% for the OPEB plan.

Assumed health care cost trend rates have a significant effect on the amounts reported by us for the 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	$ 2.8	$ (2.2)
Effect on the health care component of the accumulated postretirement benefit obligation	16.8	(14.0)

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.

Our pension trust target asset allocation is 35% equity investments, 55% fixed income investments, and 10% private equity and real estate investments. The two OPEB trusts' target asset allocations are 50% equity investments and 50% fixed income investments, and 70% equity investments and 30% fixed income investments, 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(m), 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 summarize 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:								
Unites States Equity	$ 89.0	$ —	$ —	$ 89.0	$ 24.6	$ —	$ —	$ 24.6
International Equity	85.8	—	—	85.8	24.0	—	—	24.0
Fixed income securities: *								
United States Bonds	66.2	436.5	—	502.7	24.0	48.2	—	72.2
International Bonds	8.3	31.4	—	39.7	1.6	3.0	—	4.6
	$ 249.3	$ 467.9	$ —	$ 717.2	$ 74.2	$ 51.2	$ —	$ 125.4
Investments measured at net asset value				$ 302.6				$ 76.1
Total	$ 249.3	$ 467.9	$ —	$ 1,019.8	$ 74.2	$ 51.2	$ —	$ 201.5

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

	December 31, 2017							
	Pension Plan Assets				OPEB Assets			
(in millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Asset Class								
Cash and cash equivalents	$ —	$ 6.6	$ —	$ 6.6	$ 2.1	$ 0.5	$ —	$ 2.6
Equity securities:								
United States equity	109.4	0.1	—	109.5	29.0	—	—	29.0
International equity	114.4	—	—	114.4	32.2	—	—	32.2
Fixed income securities: *								
United States bonds	75.9	467.8	—	543.7	24.4	46.3	—	70.7
International bonds	9.7	32.8	—	42.5	1.7	2.9	—	4.6
Private Equity and Real Estate	—	20.6	55.3	75.9	—	1.4	3.8	5.2
	$ 309.4	$ 527.9	$ 55.3	$ 892.6	$ 89.4	$ 51.1	$ 3.8	$ 144.3
Investments measured at net asset value				$ 241.5				$ 75.8
Total	$ 309.4	$ 527.9	$ 55.3	$ 1,134.1	$ 89.4	$ 51.1	$ 3.8	$ 220.1

* 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:

	Private Equity and Real Estate	
(in millions)	Pension	OPEB
Beginning balance at January 1, 2018	**$ 55.3**	**$ 3.8**
Realized and unrealized gains	**4.1**	**0.8**
Purchases	**9.8**	**0.7**
Liquidations	**(1.2)**	**(0.1)**
Transfers out of level 3	**(68.0)**	**(5.2)**
Ending balance at December 31, 2018	**$ —**	**$ —**

	Private Equity and Real Estate	
(in millions)	Pension	OPEB
Beginning balance at January 1, 2017	$ 11.0	$ 0.7
Realized and unrealized gains	1.9	0.2
Purchases	22.3	1.5
Transfers into level 3	20.1	1.4
Ending balance at December 31, 2017	$ 55.3	$ 3.8

Cash Flows

We expect to contribute $3.8 million to the pension plans and $0.1 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	$ 91.8	$ 11.5
2020	91.7	12.7
2021	86.7	13.3
2022	84.5	13.7
2023	81.7	14.0
2024-2028	360.5	70.2

Savings Plans

WEC Energy Group sponsors 401(k) savings plans that allow substantially all of our full-time 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, which amounts are contributed to an employee's savings plan account. Total costs incurred under all of these plans were $11.9 million in 2018, $11.7 million in 2017, and $10.4 million in 2016.

NOTE 16—INVESTMENT IN AMERICAN TRANSMISSION COMPANY

At December 31, 2016, we owned approximately 23% 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. Effective January 1, 2017, based upon input we received from the PSCW, we transferred our investment in ATC to another subsidiary of WEC Energy Group. This transaction was a non-cash equity transfer between entities under common control, and therefore, did not result in the recognition of a gain or loss. The following table provides a reconciliation of our investment in ATC during the years ended December 31:

(in millions)	2017	2016
Balance at January 1	$ 402.0	$ 382.2
Less: Transfer of ownership interest	402.0	—
Add: Earnings from equity method investment	—	55.5
Add: Capital contributions	—	16.1
Less: Distributions	—	51.7 *
Less: Other	—	0.1
Balance at December 31	$ —	$ 402.0

* Of this amount, $13.4 million was recorded as a receivable from ATC at December 31, 2016.

See Note 3, Related Parties, for more information on transactions with ATC.

NOTE 17—SEGMENT INFORMATION

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

Our utility segment includes both our electric and natural gas utility operations. Our electric utility operations are engaged in the generation, distribution, and sale of electricity to customers in southeastern Wisconsin (including metropolitan Milwaukee), east central Wisconsin, and northern Wisconsin, and to one customer in the Upper Peninsula of Michigan. Effective January 1, 2017, we transferred all of our electric distribution assets and customers located in the Upper Peninsula of Michigan to UMERC, with the exception of Tilden. See Note 3, Related Parties, and Note 21, Regulatory Environment, for additional information. Our electric utility operations also include our steam operations, which produce, distribute, and sell steam to customers in metropolitan Milwaukee, Wisconsin. Our natural gas utility operations are engaged in the purchase, distribution, and sale of natural gas to retail customers and the transportation of customer-owned natural gas in our three service areas within southeastern, east central, and northern Wisconsin.

Our other segment included Bostco, our non-utility subsidiary that was originally formed to develop and invest in real estate. In March 2017, we sold substantially all of the remaining assets of Bostco, and, in October 2018, Bostco was dissolved. See Note 2, Dispositions, for more information. Prior to January 1, 2017, our other segment also included our approximate 23% ownership interest in ATC, a for-profit, electric transmission company regulated by the FERC and certain state regulatory commissions. Effective January 1, 2017, we transferred our investment in ATC to another subsidiary of WEC Energy Group. See Note 16, Investment in American Transmission Company, for more information.

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**	**Other**	**Wisconsin Electric Power Company Consolidated**
Operating revenues	**$ 3,625.0**	**$ —**	**$ 3,625.0**
Other operation and maintenance	**1,502.4**	**—**	**1,502.4**
Depreciation and amortization	**348.1**	**—**	**348.1**
Operating income	**402.5**	**—**	**402.5**
Interest expense	**120.1**	**—**	**120.1**
Capital expenditures	**603.2**	**—**	**603.2**
Total assets	**13,538.3**	**—**	**13,538.3**

2017 ***(in millions)***	**Utility**	**Other**	**Wisconsin Electric Power Company Consolidated**
Operating revenues	$ 3,711.7	$ —	$ 3,711.7
Other operation and maintenance *	1,352.0	—	1,352.0
Depreciation and amortization	331.6	—	331.6
Operating income *	632.1	—	632.1
Interest expense	117.0	0.3	117.3
Capital expenditures	596.1	—	596.1
Total assets	13,121.6	—	13,121.6

* Includes the retroactive restatement impacts of the implementation of ASU 2017-07. See Note 15, Employee Benefits, for more information on this new standard.

2016 ***(in millions)***	**Utility**	**Other**	**Wisconsin Electric Power Company Consolidated**
Operating revenues	$ 3,792.8	$ —	$ 3,792.8
Other operation and maintenance *	1,425.5	—	1,425.5
Depreciation and amortization	325.4	—	325.4
Operating income *	634.2	—	634.2
Equity in earnings of transmission affiliate	—	55.5	55.5
Interest expense	116.6	1.0	117.6
Capital expenditures	468.9	0.6	469.5
Total assets	12,945.1	426.4	13,371.5

* Includes the retroactive restatement impacts of the implementation of ASU 2017-07. See Note 15, Employee Benefits, for more information on this new standard.

NOTE 18—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.

American Transmission Company LLC

As of December 31, 2016, we owned approximately 23% of ATC, a for-profit, electric transmission company regulated by the FERC and certain state regulatory commissions. However, effective January 1, 2017, we transferred our investment in ATC to another subsidiary of WEC Energy Group. ATC was a variable interest entity, but consolidation was not required since we were not ATC's primary beneficiary. We did not have the power to direct the activities that most significantly impacted ATC's economic performance. At December 31, 2016, we accounted for ATC as an equity method investment. See Note 16, Investment in American Transmission Company, 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 19—COMMITMENTS AND CONTINGENCIES

We 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

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

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

			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
Coal supply and transportation	2023	798.4	233.6	165.4	129.6	134.8	135.0	—
Purchased power	2043	101.6	22.7	19.4	12.3	10.4	7.6	29.2
Natural gas utility supply and transportation	2048	496.2	60.2	47.7	34.6	25.9	21.1	306.7
Total		$ 10,160.6	$ 761.9	$ 707.6	$ 677.6	$ 702.3	$ 726.7	$ 6,584.5

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 $3.0 million, $4.0 million, and $5.0 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	$ 2.9
2020	2.8
2021	0.7
2022	0.7
2023	0.7
Later years	13.9
Total	$ 21.7

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 territory were designated as partial nonattainment: 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. WEC Energy Group's plan, which includes us, is to work with its 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 WEC Energy Group's CO_2 reduction goals. As a result of WEC Energy Group's generation reshaping plan, we expect to retire approximately 1,500 MW of coal-fired generation by 2020, including PIPP, which we are required to retire by May 31, 2019, and the 2018 retirement of Pleasant Prairie power plant. 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 23.5 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 20.0 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 operations distribute and sell. For 2017, we reported aggregated CO_2 equivalent emissions of approximately 3.7 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 4.2 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 satisfy the BTA requirements.

We have received a BTA determination by the WDNR, with EPA concurrence, for our intake modification at the VAPP. Due to the retirement of the Pleasant Prairie power plant 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, 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 us 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, 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 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 $50 million.

Land Quality

Manufactured Gas Plant Remediation

We have identified sites at which we 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. We are responsible for the environmental remediation of these sites. 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.

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	**$ 24.2**	$ 30.4
Reserves for future remediation *	**13.2**	18.5

* Recorded within other long-term liabilities on our balance sheets.

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 have achieved a renewable energy percentage of 8.27% and met our compliance requirements by constructing various wind parks, a biomass facility, and by also relying on renewable energy purchases. We continue to review our renewable energy portfolio and acquire cost-effective renewables as needed to meet our requirements on an ongoing basis. The PSCW administers the renewable program related to Act 141, and we fund the program, along with other utilities, based on 1.2% of our 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 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 21, Regulatory Environment, for more information regarding the new natural gas-fired generation.

Enforcement and Litigation Matters

We 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.

NOTE 20—SUPPLEMENTAL CASH FLOW INFORMATION

(in millions)	2018	2017	2016
Cash (paid) for interest, net of amount capitalized	**$ (115.0)**	$ (115.1)	$ (116.2)
Cash (paid) received for income taxes, net	**(17.7)**	(71.7)	100.2
Significant non-cash transactions:			
Accounts payable related to construction costs	**14.0**	13.2	9.1
Transfer of investment in ATC to another subsidiary of WEC Energy Group [1] [2]	**—**	415.4	—
Transfer of net assets to UMERC [1]	**—**	61.1	—
Equity settlement of a short-term note receivable between Bostco and our parent company	**—**	4.8	—

[1] See Note 3, Related Parties, for more information on these transactions.

[2] The amount transferred includes a $13.4 million receivable for distributions approved and recorded in December 2016. See Note 16, Investment in American Transmission Company, for more information on this transaction.

NOTE 21—REGULATORY ENVIRONMENT

Tax Cuts and Jobs Act of 2017

In December 2017, we deferred for return to ratepayers, through future refunds, bill credits, or reductions in other regulatory assets, the estimated tax benefit of $1,065 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.

In May 2018, the PSCW issued an order regarding the benefits associated with the Tax Legislation. The PSCW order requires our electric utility operations to use 80% of the current 2018 and 2019 tax benefits to reduce our transmission regulatory asset. The remaining 20% is to be returned to electric customers in the form of bill credits. For our 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 our transmission regulatory asset for our electric utility operations and is being deferred for our natural gas utility operations. The timing and method of returning the remaining net tax benefit associated with the revaluation of deferred taxes for our electric and natural gas utility operations was not addressed and will be determined in a future rate proceeding.

We currently serve one retail electric customer in Michigan, and have 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.

2018 and 2019 Rates

During April 2017, we, along with WG and WPS, filed an application with the PSCW for approval of a settlement agreement we made with several of our 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 our electric, natural gas, and steam customers. Based on the PSCW order, our authorized ROE remains at 10.2%, and our current capital cost structure 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 during the base rate freeze period by accelerating the recognition of certain tax benefits. We will flow through the tax benefit of our 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.

Pursuant to the settlement agreement, we also agreed to keep our earnings sharing mechanism in place through 2019. Under this earnings sharing mechanism, if we earn above our 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 anticipate initiating a rate proceeding with the PSCW by April 1, 2019.

Natural Gas Storage Facilities in Michigan

In January 2017, WEC Energy Group signed an agreement for the acquisition of Bluewater. Bluewater owns natural gas storage facilities in Michigan that provide a portion of the current storage needs for our natural gas utility operations. As a result of this agreement, we, along with 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 requested that the PSCW review and confirm the reasonableness and prudency of our potential long-term storage service agreement and interstate natural gas transportation contracts related to the storage facilities. We, along with WG and WPS, also requested approval to amend WEC Energy Group's AIA to ensure WBS and WEC Energy Group's other subsidiaries could provide services to the storage facilities. During June 2017, the PSCW granted, subject to various conditions, these declarations and approvals, and WEC Energy Group acquired Bluewater on June 30, 2017. In September 2017, we

entered into the long-term service agreement for the natural gas storage, which was then approved by the PSCW in November 2017. See Note 3, Related Parties, for more information.

Formation of Upper Michigan Energy Resources Corporation

In December 2016, both the MPSC and the PSCW approved the operation of UMERC, a subsidiary of WEC Energy Group, 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 WPS and us, located in the Upper Peninsula of Michigan.

In August 2016, WEC Energy Group 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 new units are expected to begin commercial operation during the second quarter of 2019. Upon receiving the MPSC's approval, retirement of our 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 our customer until this new generation begins commercial operation.

NOTE 22—OTHER INCOME, NET

Total other income, net was as follows for the years ended December 31:

(in millions)	2018	2017	2016
AFUDC – Equity	**$ 3.9**	$ 3.1	$ 4.2
Non-service credit (cost) components of net periodic benefit costs	**5.7**	(6.5)	(4.7)
Interest income	**2.2**	2.3	2.2
Other, net	**8.4**	14.3	2.7
Other income, net	**$ 20.2**	$ 13.2	$ 4.4

NOTE 23—QUARTERLY FINANCIAL INFORMATION (Unaudited)

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2018					
Operating revenues	**$ 941.5**	**$ 856.2**	**$ 924.0**	**$ 903.3**	**$ 3,625.0**
Operating income	**136.4**	**104.5**	**107.8**	**53.8**	**402.5**
Net income attributed to common shareholder	**105.8**	**92.8**	**103.2**	**56.5**	**358.3**
2017					
Operating revenues	$ 972.0	$ 855.4	$ 943.8	$ 940.5	$ 3,711.7
Operating income *	186.3	146.1	164.8	134.9	632.1
Net income attributed to common shareholder	101.8	75.3	89.4	69.1	335.6

* Includes the retroactive restatement impacts of the implementation of ASU 2017-07. See Note 15, Employee Benefits, for more information on this new standard.

NOTE 24—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 $10 million to $20 million. Regarding our capital leases, while the adoption of Topic 842 changed the classification of expense related to these leases 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. Our capital leases relate to power plants leased from We Power and a long-term power purchase commitment with an unaffiliated third party. Prior to January 1, 2019, lease expense related to our We Power leases was recorded as rent expense in other operation and maintenance, while lease expense related to the power purchase commitment was recorded in cost of sales. Subsequent to our adoption of Topic 842, lease expense related to these capital leases 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.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Our management, with the participation of our principal executive officer and principal financial officer, has evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Based upon such evaluation, our principal executive officer and principal financial officer have concluded that, as of the end of such period, our disclosure controls and procedures are effective (i) in recording, processing, summarizing and reporting, on a timely basis, information required to be disclosed by us in the reports that we file or submit under the Exchange Act and (ii) to ensure that information required to be disclosed in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our 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 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.

This Annual Report on Form 10-K does not include an attestation report of our independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by our independent registered public accounting firm pursuant to rules of the SEC that permit us to provide only management's report in this annual report.

Changes in Internal Control Over Financial Reporting

During 2018, WEC Energy Group completed an enterprise resource planning (ERP) system integration project to bring all of its subsidiaries, including us, 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.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE OF THE REGISTRANT

The information under "Election of Directors," "Section 16(a) Beneficial Ownership Reporting Compliance," "Corporate Governance – Frequently Asked Questions: What is the process used to identify director nominees and how do I recommend a nominee to WEC Energy Group's Corporate Governance Committee?," "Corporate Governance – Frequently Asked Questions: Are the WEC Energy Group Audit and Oversight and Compensation Committees comprised solely of independent directors?," "Corporate Governance – Frequently Asked Questions: Are all the members of the WEC Energy Group Audit Committee financially literate and does the committee have an 'audit committee financial expert'?," "Corporate Governance – Frequently Asked Questions: Does the Board have a nominating committee?," and "Committees of the WEC Energy Group Board of Directors – Audit and Oversight" in our Definitive Information Statement on Schedule 14C to be filed with the SEC for our Annual Meeting of Shareholders to be held April 25, 2019 (the "2019 Annual Meeting Information Statement") is incorporated herein by reference. Also see "Executive Officers of the Registrant" in Part I of this report.

WEC Energy Group has adopted a written code of ethics, referred to as its Code of Business Conduct. We are a subsidiary of WEC Energy Group, and as such, all of our directors, executive officers, and employees, including our principal executive officer, principal financial officer and principal accounting officer, have a responsibility to comply with WEC Energy Group's Code of Business Conduct. WEC Energy Group has posted its Code of Business Conduct in the "Governance" section on its website, www.wecenergygroup.com. WEC Energy Group has not provided any waiver to the Code for any director, executive officer, or other employee. Any amendments to, or waivers for directors and executive officers from, the Code of Business Conduct will be disclosed on WEC Energy Group's website or in a current report on Form 8-K.

ITEM 11. EXECUTIVE COMPENSATION

The information under "Compensation Discussion and Analysis," "Executive Compensation," "Director Compensation," "Committees of the WEC Energy Group Board of Directors – Compensation," "Compensation Committee Report," "Pay Ratio Disclosure," "Risk Analysis of Compensation Policies and Practices," and "Certain Relationships and Related Transactions – Compensation Committee Interlocks and Insider Participation" in the 2019 Annual Meeting Information Statement is incorporated herein by reference.

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

All of our Common Stock is owned by our parent company, WEC Energy Group, 231 West Michigan Street, P.O. Box 1331, Milwaukee, Wisconsin 53201. Our directors and director nominees, who are all executive officers of WE, as well as our other executive officers, do not own any of our voting securities. The information concerning their beneficial ownership in WEC Energy Group common stock set forth under "Stock Ownership of Directors, Nominees and Executive Officers" in the 2019 Annual Meeting Information Statement is incorporated herein by reference.

We do not have any equity compensation plans under which our equity securities may be issued. Our directors, officers and certain employees participate in the compensation plans of WEC Energy Group.

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

The information under "Corporate Governance – Frequently Asked Questions: Who are the independent directors?," "Corporate Governance – Frequently Asked Questions: What are the WEC Energy Group Board's standards of independence?," "Corporate Governance – Frequently Asked Questions: Are the WEC Energy Group Audit and Oversight and Compensation Committees comprised solely of independent directors?," "Corporate Governance – Frequently Asked Questions: Does the Company have policies and procedures in place to review and approve related party transactions?," and "Certain Relationships and Related Transactions" in the 2019 Annual Meeting Information Statement is incorporated herein by reference. A full description of the guidelines the WEC Energy Group Board uses to determine director independence is located in Appendix A of WEC Energy Group's Corporate Governance Guidelines, which can be found on its website, www.wecenergygroup.com.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information regarding the fees paid to, and services performed by, our independent auditors and the pre-approval policy of our audit and oversight committee under "Independent Auditors' Fees and Services" in the 2019 Annual Meeting Information Statement is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

1. Financial Statements and Report of Independent Registered Public Accounting Firm Included in Part II of This Report

Description	Page in 10-K
Report of Independent Registered Public Accounting Firm.	50
Consolidated Income Statements for the three years ended December 31, 2018, 2017, and 2016.	51
Consolidated Balance Sheets at December 31, 2018 and 2017.	52
Consolidated Statements of Cash Flows for the three years ended December 31, 2018, 2017, and 2016.	53
Consolidated Statements of Equity for the three years ended December 31, 2018, 2017, and 2016.	54
Consolidated Statements of Capitalization at December 31, 2018 and 2017.	55
Notes to Consolidated Financial Statements.	56

2. Financial Statement Schedules Included in Part IV of This Report

Schedule II, Valuation and Qualifying Accounts, for the three years ended December 31, 2018, 2017, and 2016. 104

Other schedules are omitted because of the absence of conditions under which they are required or because the required information is given in the financial statements or notes thereto.

3. Exhibits and Exhibit Index

The following exhibits are filed or furnished with or incorporated by reference in the report with respect to Wisconsin Electric Power Company (File No. 001-01245). An asterisk (*) indicates incorporation by reference pursuant to Exchange Act Rule 12b-32. Each management contract and compensatory plan or arrangement required to be filed as an exhibit to this report pursuant to Item 15(b) of Form 10-K is identified below by two asterisks (**) following the description of the exhibit.

Number	Exhibit	
3	**Articles of Incorporation and By-laws**	
	3.1*	Restated Articles of Incorporation of WE, as amended and restated effective January 10, 1995. (Exhibit (3)-1 to WE's 12/31/94 Form 10-K.)
	3.2*	Bylaws of WE, as amended to May 1, 2000. (Exhibit (3)-2 to WE's 03/31/00 Form 10-Q.)
4	**Instruments defining the rights of security holders, including indentures**	
	4.1*	Reference is made to Article III of the Restated Articles of Incorporation of WE. (See Exhibit 3.1 above.)
	Indentures and Securities Resolutions:	
	4.2*	Indenture for Debt Securities of WE (the "WE Indenture"), dated December 1, 1995. (Exhibit (4)-1 to WE's 12/31/95 Form 10-K.)
	4.3*	Securities Resolution No. 1 of WE under the WE Indenture, dated December 5, 1995. (Exhibit (4)-2 to WE's 12/31/95 Form 10-K.)

Number	Exhibit
4.4*	Securities Resolution No. 3 of WE under the WE Indenture, dated May 27, 1998. (Exhibit (4)-1 to WE's 06/30/98 Form 10-Q.)
4.5*	Securities Resolution No. 5 of WE under the WE Indenture, dated as of May 1, 2003. (Exhibit 4.47 filed with Post-Effective Amendment No. 1 to WE's Registration Statement on Form S-3 (File No. 333-101054), filed May 6, 2003.)
4.6*	Securities Resolution No. 7 of WE under the WE Indenture, dated as of November 2, 2006. (Exhibit 4.1 to WE's 11/02/06 Form 8-K.)
4.7*	Securities Resolution No. 10 of WE under the WE Indenture, dated as of December 8, 2009. (Exhibit 4.1 to WE's 12/08/09 Form 8-K.)
4.8*	Securities Resolution No. 11 of WE under the WE Indenture, dated as of September 7, 2011. (Exhibit 4.1 to WE's 09/07/11 Form 8-K.)
4.9*	Securities Resolution No. 12 of WE under the WE Indenture, dated as of December 5, 2012. (Exhibit 4.1 to WE's 12/05/12 Form 8-K.)
4.10*	Securities Resolution No. 14 of WE under the WE Indenture, dated as of May 12, 2014. (Exhibit 4.1 to WE's 05/12/14 Form 8-K.)
4.12*	Securities Resolution No. 15 of WE under the WE Indenture, dated as of May 14, 2015. (Exhibit 4.1 to WE's 05/14/15 Form 8-K.)
4.12*	Securities Resolution No. 16 of WE under the WE Indenture, dated as of November 13, 2015. (Exhibit 4.1 to WE's 11/13/15 Form 8-K.)
4.13*	Securities Resolution No. 17 of WE under the WE Indenture, dated as of October 1, 2018. (Exhibit 4.1 to WE's 10/01/18 Form 8-K.)
	Certain agreements and instruments with respect to unregistered long-term debt not exceeding 10 percent of the total assets of the Registrant and its subsidiary on a consolidated basis have been omitted as permitted by related instructions. The Registrant agrees pursuant to Item 601(b)(4) of Regulation S-K to furnish to the Securities and Exchange Commission, upon request, a copy of all such agreements and instruments.
10	**Material Contracts**
10.1	WEC Energy Group Supplemental Pension Plan, Amended and Restated Effective as of January 1, 2018.**
10.2	Legacy Wisconsin Energy Corporation Executive Deferred Compensation Plan, Amended and Restated as of January 1, 2018.**
10.3	WEC Energy Group Executive Deferred Compensation Plan, Amended and Restated Effective as of January 1, 2018.**
10.4	WEC Energy Group Non-Qualified Retirement Savings Plan, Amended and Restated Effective as of January 1, 2018.**
10.5	WEC Energy Group Supplemental Long Term Disability Plan, Amended and Restated Effective as of January 1, 2017.**
10.6	WEC Energy Group Short-Term Performance Plan, Amended and Restated Effective as of January 1, 2019.**
10.7*	Wisconsin Energy Corporation 2014 Rabbi Trust Agreement by and between Wisconsin Energy Corporation and The Northern Trust Company dated February 23, 2015, regarding the trust established to provide a source of funds to assist in meeting the liabilities under various nonqualified deferred compensation plans made between Wisconsin Energy Corporation or its subsidiaries and various plan participants. (Exhibit 10.13 to Wisconsin Energy Corporation's 12/31/14 Form 10-K (File No. 001-09057).)**

Number	Exhibit
10.8*	Letter Agreement by and between WEC Energy Group, Inc. and Gale E. Klappa, dated as of December 7, 2017. (Exhibit 10.1 to WEC Energy Group's 12/08/17 Form 8-K. (File No. 001-09057).)**
10.9*	Terms and Conditions Governing Gale Klappa's Restricted Stock Award Under the 1993 Omnibus Stock Incentive Plan. (Exhibit 10.2 to WEC Energy Group's 12/08/17 Form 8-K. (File No. 001-09057).)**
10.10*	Letter Agreement by and between WEC Energy Group, Inc. and Gale E. Klappa, dated as of January 17, 2019. (Exhibit 10.1 to WEC Energy Group's 01/22/19 Form 8-K. (File No. 001-09057).)**
10.11*	Letter Agreement by and between Wisconsin Energy Corporation and Robert Garvin, dated January 31, 2011. (Exhibit 10.1 to Wisconsin Energy Corporation's 03/31/11 Form 10-Q (File No. 001-09057).)**
10.12*	Letter Agreement by and between Wisconsin Energy Corporation and Joseph Kevin Fletcher, dated as of August 17, 2011. (Exhibit 10.1 to Wisconsin Energy Corporation's 09/30/11 Form 10-Q (File No. 001-09057).)**
10.13*	Letter Agreement by and between WEC Energy Group, Inc. and Margaret C. Kelsey, dated as of July 19, 2017. (Exhibit 10.1 to WEC Energy Group's 09/30/17 Form 10-Q. (File No. 001-09057).)**
10.14*	1993 Omnibus Stock Incentive Plan, Amended and Restated Effective as of January 1, 2016. (Exhibit 10.19 to WEC Energy Group's 12/31/15 Form 10-K (File No. 001-09057).)**
10.15*	Terms and Conditions Governing Non-Qualified Stock Option Award under the 1993 Omnibus Stock Incentive Plan. (Exhibit 10.1 to Wisconsin Energy Corporation's 09/30/07 Form 10-Q (File No. 001-09057).)**
10.16*	WEC Energy Group Performance Unit Plan, amended and restated effective as of January 1, 2017. (Exhibit 10.1 to WEC Energy Group's 12/01/16 Form 8-K (File No. 001-09057).)**
10.17*	2016 WEC Energy Group Restricted Stock Award Terms and Conditions governing awards under the 1993 Omnibus Stock Incentive Plan. (Exhibit 10.27 to WEC Energy Group's 12/31/15 Form 10-K (File No. 001-09057).)**
10.18*	Wisconsin Energy Corporation Terms and Conditions Governing Non-Qualified Stock Option Award for option awards under the 1993 Omnibus Stock Incentive Plan, approved December 4, 2014. (Exhibit 10.3 to Wisconsin Energy Corporation's 12/04/14 Form 8-K (File No. 001-09057).)**
10.19*	2016 WEC Energy Group Terms and Conditions Governing Non-Qualified Stock Option Award for option awards under the 1993 Omnibus Stock Incentive Plan. (Exhibit 10.29 to WEC Energy Group's Form 12/31/15 Form 10-K (File No. 001-09057).)**
10.20*	Port Washington I Facility Lease Agreement between Port Washington Generating Station LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of May 28, 2003. (Exhibit 10.7 to WE's 06/30/03 Form 10-Q.)
10.21*	Port Washington II Facility Lease Agreement between Port Washington Generating Station LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of May 28, 2003. (Exhibit 10.8 to WE's 06/30/03 Form 10-Q.)
10.22*	Elm Road I Facility Lease Agreement between Elm Road Generating Station Supercritical, LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of November 9, 2004. (Exhibit 10.56 to Wisconsin Energy Corporation's 12/31/04 Form 10-K (File No. 001-09057).)
10.23*	Elm Road II Facility Lease Agreement between Elm Road Generating Station Supercritical, LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of November 9, 2004. (Exhibit 10.57 to Wisconsin Energy Corporation's 12/31/04 Form 10-K (File No. 001-09057).)
10.24*	Point Beach Nuclear Plant Power Purchase Agreement between FPL Energy Point Beach, LLC and Wisconsin Electric Power Company, dated as of December 19, 2006 (the "PPA"). (Exhibit 10.1 to Wisconsin Energy Corporation's 03/31/08 Form 10-Q (File No. 001-09057).)
10.25*	Letter Agreement between Wisconsin Electric Power Company and FPL Energy Point Beach, LLC, dated October 31, 2007, which amends the PPA. (Exhibit 10.45 to Wisconsin Energy Corporation's 12/31/07 Form 10-K (File No. 001-09057).)

Number	Exhibit
23	**Consents of experts and counsel**
23.1	Consent of Independent Registered Public Accounting Firm for WE.
31	**Rule 13a-14(a)/15d-14(a) Certifications**
31.1	Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	**Section 1350 Certifications**
32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101	**Interactive Data File**

ITEM 16. FORM 10-K SUMMARY

None.

SCHEDULE II
WISCONSIN ELECTRIC POWER COMPANY
VALUATION AND QUALIFYING ACCOUNTS

Allowance for Doubtful Accounts *(in millions)*	Balance at Beginning of Period	Transfer of Net Assets to UMERC [1]	Expense [2]	Deferral	Net Write-offs [3]	Balance at End of Period
December 31, 2018	**$ 39.5**	**$ —**	**$ 32.3**	**$ (9.1)**	**$ (21.8)**	**$ 40.9**
December 31, 2017	40.9	(0.3)	31.2	(6.4)	(25.9)	39.5
December 31, 2016	43.0	—	31.1	(5.7)	(27.5)	40.9

(1) See Note 3, Related Parties, for more information.

(2) Net of recoveries.

(3) Represents amounts written off to the reserve, net of adjustments to regulatory assets.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

WISCONSIN ELECTRIC POWER COMPANY

By /s/ J. KEVIN FLETCHER

Date: February 26, 2019

J. Kevin Fletcher
Chairman of the Board and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

/s/ J. KEVIN FLETCHER	February 26, 2019
J. Kevin Fletcher, Chairman of the Board and Chief Executive Officer and Director -- Principal Executive Officer	
/s/ SCOTT J. LAUBER	February 26, 2019
Scott J. Lauber, Executive Vice President, Chief Financial Officer, Treasurer and Director -- Principal Financial Officer	
/s/ WILLIAM J. GUC	February 26, 2019
William J. Guc, Vice President and Controller -- Principal Accounting Officer	
/s/ MARGARET C. KELSEY	February 26, 2019
Margaret C. Kelsey, Director	
/s/ GALE E. KLAPPA	February 26, 2019
Gale E. Klappa, Director	
/s/ TOM METCALFE	February 26, 2019
Tom Metcalfe, Director	

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-222429 on Form S-3 of our report dated February 26, 2019, relating to the consolidated financial statements and financial statement schedule of Wisconsin Electric Power Company and subsidiary (the "Company"), appearing in this Annual Report on Form 10-K of the Company for the year ended December 31, 2018.

/s/ DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
February 26, 2019

Exhibit 31.1

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

I, J. Kevin Fletcher, certify that:

1. I have reviewed this Annual Report on Form 10-K of Wisconsin Electric Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an Annual Report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2019

/s/ J. KEVIN FLETCHER

J. Kevin Fletcher
Chief Executive Officer and President
(Principal Executive Officer)

Exhibit 31.2

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

I, Scott J. Lauber, certify that:

1. I have reviewed this Annual Report on Form 10-K of Wisconsin Electric Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an Annual Report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2019

/s/ SCOTT J. LAUBER

Scott J. Lauber
Senior Executive Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

Exhibit 32.1

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

In connection with the Annual Report of Wisconsin Electric Power Company (the "Company") on Form 10-K for the period ended December 31, 2018, as filed with the Securities and Exchange Commission on February 26, 2019 (the "Report"), I, J. Kevin Fletcher, Chairman and Chief Executive Officer of the Company, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

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

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

/s/ J. KEVIN FLETCHER

J. Kevin Fletcher
Chief Executive Officer and President

February 26, 2019

Exhibit 32.2

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

In connection with the Annual Report of Wisconsin Electric Power Company (the "Company") on Form 10-K for the period ended December 31, 2018, as filed with the Securities and Exchange Commission on February 26, 2019 (the "Report"), I, Scott J. Lauber, Executive Vice President, CFO and Treasurer of the Company, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

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

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

/s/ SCOTT J. LAUBER

Scott J. Lauber
Senior Executive Vice President, Chief Financial Officer, and Treasurer
February 26, 2019

WISCONSIN GAS LLC

FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2018

WISCONSIN GAS LLC
FINANCIAL STATEMENTS
For the Year Ended December 31, 2018
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GLOSSARY OF TERMS AND ABBREVIATIONS

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

Subsidiaries and Affiliates	
Bluewater	Bluewater Natural Gas Holding, LLC
Integrys	Integrys Holding, Inc.
WBS	WEC Business Services LLC
WE	Wisconsin Electric Power Company
WEC Energy Group	WEC Energy Group, Inc.
WPS	Wisconsin Public Service Corporation

Federal and State Regulatory Agencies	
EPA	United States Environmental Protection Agency
PSCW	Public Service Commission of Wisconsin

Accounting Terms	
AFUDC	Allowance for Funds Used During Construction
ASU	Accounting Standards Update
FASB	Financial Accounting Standards Board
GAAP	Generally Accepted Accounting Principles
OPEB	Other Postretirement Employee Benefits

Environmental Terms	
CO_2	Carbon Dioxide

Measurements	
Dth	Dekatherm

Other Terms and Abbreviations	
AIA	Affiliated Interest Agreement
ROE	Return on Equity
Tax Legislation	Tax Cuts and Jobs Act of 2017

FINANCIAL STATEMENTS AND NOTES

A. INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Member of Wisconsin Gas LLC:

Milwaukee, Wisconsin

We have audited the accompanying financial statements of Wisconsin Gas LLC (the "Company"), which comprise the balance sheets and statements of capitalization as of December 31, 2018 and 2017, and the related income statements, statements of changes in member's equity, and statements of cash flows for the years then ended, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Wisconsin Gas LLC as of December 31, 2018 and 2017, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
March 26, 2019

WISCONSIN GAS LLC

B. INCOME STATEMENTS

Year Ended December 31 *(in millions)*	2018	2017
Operating revenues	**$ 649.6**	$ 614.3
Operating expenses		
Cost of natural gas sold	**353.1**	316.4
Other operation and maintenance	**115.1**	114.2
Depreciation and amortization	**51.8**	48.6
Property and revenue taxes	**6.8**	6.2
Total operating expenses	**526.8**	485.4
Operating income	**122.8**	128.9
Other income, net	**1.9**	6.9
Interest expense	**24.8**	21.9
Other expense	**(22.9)**	(15.0)
Income before income taxes	**99.9**	113.9
Income tax expense	**24.8**	60.7
Net income	**$ 75.1**	$ 53.2

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

WISCONSIN GAS LLC

C. BALANCE SHEETS

At December 31 *(in millions)*	2018	2017
Assets		
Current assets		
Cash and cash equivalents	**$ 0.5**	$ 1.8
Accounts receivable and unbilled revenues, net of reserves of $18.3 and $18.4, respectively	**125.6**	132.6
Accounts receivable from related parties	**72.4**	0.8
Materials, supplies, and inventory:		
Natural gas in storage	**56.8**	45.2
Materials and supplies	**4.8**	4.9
Other	**10.3**	11.0
Current assets	**270.4**	196.3
Long-term assets		
Property, plant, and equipment, net of accumulated depreciation of $740.6 and $722.1, respectively	**1,683.2**	1,550.8
Regulatory assets	**250.7**	206.1
Prepaid pension and OPEB costs	**169.0**	162.3
Goodwill	**95.9**	95.9
Other	**14.3**	18.7
Long-term assets	**2,213.1**	2,033.8
Total assets	**$ 2,483.5**	$ 2,230.1
Liabilities and Member's Equity		
Current liabilities		
Short-term debt	**$ 277.3**	$ 205.9
Accounts payable	**55.7**	41.4
Accounts payable to related parties	**69.7**	6.3
Customer credit balances	**12.1**	12.9
Amounts refundable to customers	**9.8**	16.4
Other	**15.0**	24.7
Current liabilities	**439.6**	307.6
Long-term liabilities		
Long-term debt	**486.3**	486.0
Regulatory liabilities	**402.5**	383.0
Deferred income taxes	**203.2**	192.6
Environmental remediation liabilities	**77.7**	41.2
Other	**29.9**	27.5
Long-term liabilities	**1,199.6**	1,130.3
Commitments and contingencies (Note 13)		
Member's equity	**844.3**	792.2
Total liabilities and member's equity	**$ 2,483.5**	$ 2,230.1

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

WISCONSIN GAS LLC

D. STATEMENTS OF CASH FLOWS

Year Ended December 31 *(in millions)*	2018	2017
Operating activities		
Net income	**$ 75.1**	$ 53.2
Reconciliation to cash provided by operating activities		
Depreciation and amortization	**51.8**	48.6
Deferred income taxes, net	**15.3**	40.8
Contributions and payments related to pension and OPEB plans	**(3.2)**	(2.7)
Change in –		
Accounts receivable and unbilled revenues	**(64.6)**	(12.4)
Materials, supplies, and inventories	**(11.5)**	(3.5)
Prepaid taxes	**(0.5)**	4.5
Other current assets	**0.9**	(3.3)
Accounts payable	**74.4**	4.7
Amounts refundable to customers	**(6.3)**	4.1
Accrued taxes	**(9.4)**	11.7
Other current liabilities	**(1.0)**	(0.3)
Other, net	**0.3**	(1.8)
Net cash provided by operating activities	**121.3**	143.6
Investing activities		
Capital expenditures	**(159.8)**	(154.3)
Payments for assets transferred from affiliates	**(15.6)**	—
Proceeds on cash surrender value of life insurance	**4.3**	—
Other, net	**0.1**	(1.3)
Net cash used in investing activities	**(171.0)**	(155.6)
Financing activities		
Change in short-term debt	**71.4**	54.4
Equity contribution from parent	**27.0**	—
Payment of distributions to parent	**(50.0)**	(45.0)
Net cash provided by financing activities	**48.4**	9.4
Net change in cash and cash equivalents	**(1.3)**	(2.6)
Cash and cash equivalents at beginning of year	**1.8**	4.4
Cash and cash equivalents at end of year	**$ 0.5**	$ 1.8

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

WISCONSIN GAS LLC

E. STATEMENTS OF CHANGES IN MEMBER'S EQUITY

(in millions)	2018	2017
Member's Equity at January 1	**$ 792.2**	$ 783.9
Net income	**75.1**	53.2
Equity contribution from parent	**27.0**	—
Payment of distributions to parent	**(50.0)**	(45.0)
Other	—	0.1
Member's Equity at December 31	**$ 844.3**	$ 792.2

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

WISCONSIN GAS LLC

F. STATEMENTS OF CAPITALIZATION

At December 31 *(in millions)*			2018	2017
Member's equity (see Statements of Changes in Member's Equity)			**$ 844.3**	$ 792.2
Long-term debt	**Interest Rate**	**Year Due**		
Debentures (unsecured)	3.53%	2025	**200.0**	200.0
	5.90%	2035	**90.0**	90.0
	3.71%	2046	**200.0**	200.0
Total			**490.0**	490.0
Unamortized debt issuance costs			**(3.1)**	(3.4)
Unamortized discount, net			**(0.6)**	(0.6)
Total long-term debt			**486.3**	486.0
Total long-term capitalization			**$ 1,330.6**	$ 1,278.2

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

G. NOTES TO FINANCIAL STATEMENTS
December 31, 2018

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Nature of Operations—As used in these notes, the term "financial statements" includes the income statements, balance sheets, statements of cash flows, statements of changes in member's equity, and statements of capitalization, unless otherwise noted. In this report, when we refer to "us," "we," "our," or "ours," we are referring to Wisconsin Gas LLC.

We are a public utility engaged in the distribution of natural gas throughout Wisconsin and are a wholly owned subsidiary of WEC Energy Group. We are subject to the jurisdiction of, and regulation by, the PSCW, which has general supervisory and regulatory powers over virtually all phases of the public utility industry in Wisconsin. We have combined many common functions with WE, another utility subsidiary of WEC Energy Group, and operate together under the trade name "We Energies".

(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 3, 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 natural gas 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

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 our tariffs. 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. Our 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 our tariffs, which have been approved by the PSCW. 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.

Our tariffs include various rate mechanisms that allow us to recover or refund changes in prudently incurred costs from rate case-approved amounts. Our rates include a one-for-one recovery mechanism 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, our residential tariffs 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.

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.

(e) Materials, Supplies, and Inventories—We record substantially all materials, supplies, and natural gas in storage inventories 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 PSCW 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 4, 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 as approved by the PSCW. Our annual utility composite depreciation rate was 2.30% in 2018 and 2017.

Third parties reimburse us 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 5, 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 member's equity (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.

Approximately 50% of our retail jurisdictional construction work in progress expenditures are subject to the AFUDC calculation. Our average AFUDC retail rate was 8.33% in 2018 and 2017.

(i) Asset Impairment—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. 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.

(j) Goodwill—Goodwill represents the excess of the cost of an acquisition over the fair value of the identifiable net assets acquired. At December 31, 2018 and 2017, we had gross goodwill of $441.9 million and accumulated goodwill impairment losses of $346.0 million, resulting in a net goodwill balance of $95.9 million. Our goodwill balances did not change during the years ended December 31, 2018 and 2017.

Goodwill is subject to an annual impairment test. Interim impairment tests are performed when impairment indicators are present. Our reporting unit containing goodwill as of July 1, 2018, performed an annual goodwill impairment test during the third quarter of 2018. No impairments resulted from this test. 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 goodwill over its implied fair value.

(k) Stock-Based Compensation—Our employees participate in the WEC Energy Group stock-based compensation plans. In accordance with the WEC Energy Group shareholder approved WEC Energy Group 1993 Omnibus Stock Incentive Plan, Amended and Restated Effective as of January 1, 2016, WEC Energy Group provides long-term incentives through its equity interests to its 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 WEC Energy Group common stock, cash, or a combination thereof. Stock-based compensation expense related to these awards is allocated to us based on the outstanding awards held by our employees and our allocation of labor costs. For the years ended December 31, 2018 and 2017, we recorded stock-based compensation expense of $1.8 million and $1.2 million, respectively.

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

(l) 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. We and our subsidiary are included in WEC Energy Group's consolidated federal and state income tax returns. In accordance with our tax allocation agreement with WEC Energy Group, we are allocated income tax payments and refunds based on our separate tax computation. See Note 9, Income Taxes, for more information.

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

(m) 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 the levels of the fair value hierarchy as of the end of the reporting period.

See Note 10, Fair Value Measurements, for more information.

(n) Derivative Instruments—We use derivatives as part of our risk management program to manage the risks associated with the price volatility of natural gas costs for the benefit of our customers. Our approach is non-speculative and is designed to mitigate risk. Our regulated hedging program is approved by the PSCW.

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

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

Derivative accounting rules provide the option to present certain asset and liability derivative positions net on the balance sheets and to net the related cash collateral against these net derivative positions. We elected not to net these items. On our balance sheets, cash collateral provided to others is reflected in other current assets. See Note 11, Derivative Instruments, for more information.

(o) Employee Benefits—The costs of pension and OPEB plans are expensed over the periods during which employees render service. These costs are distributed among WEC Energy Group's subsidiaries based on current employment status and actuarial

calculations, as applicable. The PSCW allows recovery in rates for our net periodic benefit cost calculated under GAAP. See Note 12, Employee Benefits, for more information.

(p) Customer Credit Balances—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 presented as customer credit balances on our balance sheets.

(q) 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 manufactured gas plant sites. See Note 13, Commitments and Contingencies, for more information.

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.

We 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 PSCW approval.

We review our estimated costs of remediation annually for our manufactured gas plant 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.

(r) Customer Concentrations of Credit Risk—The geographic concentration of our customers in our service territory 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. Our credit risk exposure is mitigated by our recovery mechanism 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.

(s) Subsequent Events—Subsequent events were evaluated for potential recognition or disclosure through March 26, 2019, which is the date the financial statements were available to be issued.

NOTE 2—RELATED PARTIES

We routinely enter into transactions with related parties, including WEC Energy Group and its other subsidiaries.

We provide and receive services, property, and other items of value to and from our parent, WEC Energy Group, and other subsidiaries of WEC Energy Group.

Following WEC Energy Group's acquisition of Integrys on June 29, 2015, an AIA (Non-WBS AIA) went into effect. The Non-WBS AIA governed the provision and receipt of services by WEC Energy Group's subsidiaries, except that WBS continued to provide services to Integrys and its subsidiaries only under the existing WBS AIAs. WBS provided services to WEC Energy Group and the former Wisconsin Energy Corporation subsidiaries, including us, under interim WBS AIAs. The PSCW and all other relevant state commissions approved the Non-WBS AIA or granted appropriate waivers related to the Non-WBS AIA.

Services under the Non-WBS AIA were subject to various pricing methodologies. All services provided by any regulated subsidiary to another regulated subsidiary were priced at cost. All services provided by any regulated subsidiary to any nonregulated subsidiary were priced at the greater of cost or fair market value. All services provided by any nonregulated subsidiary to any regulated subsidiary were priced at the lesser of cost or fair market value. All services provided by any regulated or nonregulated subsidiary to WBS were priced at cost.

WBS provided several categories of services (including financial, human resources, and administrative services) to us pursuant to the WBS AIAs, which were approved, or from which we were granted appropriate waivers, by the appropriate regulators, including the PSCW. As required by Federal Energy Regulatory Commission regulations for centralized service companies, WBS renders services at cost. The PSCW must be notified prior to making changes to the services offered under and the allocation methods specified in the WBS AIAs. Other modifications or amendments to the WBS AIAs would require PSCW approval. Recovery of allocated costs is addressed in our rate cases.

A new AIA took effect January 1, 2017. The new agreement replaced the previous agreements. The pricing methodology and services under this new agreement are substantially identical to those under the agreements that were replaced. All of the applicable state commissions approved modifications to the new AIA to incorporate WEC Energy Group's acquisition of Bluewater. See below for more information about the acquisition.

The following table shows activity associated with our related party transactions for the years ended December 31:

(in millions)	2018		2017
Transactions with WBS [1]			
Billings to WBS	**$ 7.9**		$ 0.1
Billings from WBS	**40.1**	[2]	20.2
Billings from WEC Energy Group [1]	**—**		10.3
Transactions with WE			
Natural gas sales to WE	**5.3**		5.3
Billings to WE [1]	**32.6**		23.1
Billings from WE [1]	**59.0**	[2]	64.0
Transactions with Bluewater [3]			
Storage service fees	**20.9**		2.1

[1] Includes amounts billed for services, pass through costs, and other items in accordance with the approved AIAs.

[2] Includes $10.3 million and $5.3 million for the transfer of certain software assets to us from WBS and WE, respectively, for the year ended December 31, 2018.

[3] WEC Energy Group's acquisition of Bluewater was completed June 30, 2017.

Parent Company's Acquisition of Natural Gas Storage Facilities in Michigan

On June 30, 2017, our parent company completed its acquisition of Bluewater for $226.0 million. Bluewater owns natural gas storage facilities in Michigan that provide a portion of the current storage needs for our natural gas utility operations. In September 2017, we entered into a long-term service agreement with a wholly owned subsidiary of Bluewater to take a portion of the storage, which was then approved by the PSCW in November 2017. See Note 15, Regulatory Environment, for more information.

NOTE 3—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 revenues and cash flows are affected by economic factors. Natural gas revenues are further disaggregated by customer class. Each customer class has different expectations of service, natural gas and demand requirements, and are impacted by regulatory activities within Wisconsin.

Comparable amounts have not been presented for the year ended December 31, 2017, 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)	Natural Gas Operating Revenues
Year ended December 31, 2018	
Natural gas utility revenues from contracts with customers	**$ 646.3**
Other operating revenues	**3.3**
Total natural gas operating revenues	**$ 649.6**

Revenues from Contracts with Customers

Natural Gas Utility Operating Revenues

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

(in millions)	Natural Gas Utility Operating Revenues
Year Ended December 31, 2018	
Residential	**$ 390.2**
Commercial and industrial	**203.6**
Total retail revenues	**593.8**
Transport	**45.6**
Other utility revenues *	**6.9**
Total natural gas utility operating revenues	**$ 646.3**

* Includes amounts collected from customers for purchased gas adjustment costs.

Other Operating Revenues

Other operating revenues consist primarily of the following:

(in millions)	Year Ended December 31, 2018
Late payment charges	**$ 3.2**
Leases	**0.1**
Total other operating revenues	**$ 3.3**

NOTE 4—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]	**$ 164.4**	$ 157.6	12
Environmental remediation costs [4]	**85.6**	47.3	13
Other, net	**0.7**	1.2	
Total regulatory assets	**$ 250.7**	$ 206.1	

(1) Based on prior and current rate treatment, we believe it is probable that we will continue to recover from customers the regulatory assets in this table.

(2) As of December 31, 2018, we had $7.9 million of regulatory assets not earning a return. The regulatory assets not earning a return relate to certain environmental remediation costs, the recovery of which depends on the timing of the actual expenditures. 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 $7.9 million related to these environmental remediation costs. The remaining $77.7 million represents our estimated future cash expenditures.

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]	**$ 198.1**	$ 188.0	9
Removal costs [2]	**180.3**	173.8	
Uncollectible expense [3]	**14.1**	18.3	1(d)
Natural gas costs refundable through rate adjustments [4]	**9.8**	16.4	1(d)
Other, net	**10.0**	2.9	
Total regulatory liabilities	**$ 412.3**	$ 399.4	
Balance sheet presentation			
Amounts refundable to customers	**$ 9.8**	$ 16.4	
Regulatory liabilities	**402.5**	383.0	
Total regulatory liabilities	**$ 412.3**	$ 399.4	

(1) For information on the regulatory treatment of the impacts of the Tax Legislation, see Note 15, Regulatory Environment.

(2) Represents amounts collected from customers to cover the future cost of property, plant, and equipment removals that are not legally required.

(3) Represents amounts refundable to customers related to our uncollectible expense tracking mechanism. This mechanism allows us to recover or refund the difference between actual uncollectible write-offs and the amounts recovered in rates.

(4) Represents an over-collection of natural gas costs that will be refunded to customers in the future. When the rates we charge to customers include natural gas costs that are higher than our actual natural gas costs, any over-collection is refunded to customers.

NOTE 5—PROPERTY, PLANT, AND EQUIPMENT

Property, plant, and equipment consisted of the following utility and non-utility assets at December 31:

(in millions)	2018	2017
Natural gas - distribution, storage, and transmission	**$ 2,254.6**	$ 2,128.0
Other	**136.3**	126.2
Less: Accumulated depreciation	**740.6**	722.1
Net	**1,650.3**	1,532.1
Construction work in progress	**28.9**	14.7
Net utility property, plant, and equipment	**1,679.2**	1,546.8
Non-utility property, plant, and equipment	**4.0**	4.0
Total property, plant, and equipment	**$ 1,683.2**	$ 1,550.8

NOTE 6—MEMBER'S EQUITY

Various financing arrangements and regulatory requirements impose certain restrictions on our ability to transfer funds to WEC Energy Group in the form of cash distributions, loans, or advances. In addition, Wisconsin law prohibits us from making loans to or guaranteeing obligations of WEC Energy Group.

In accordance with our most recent rate order, we may not pay distributions above the test year forecasted amount reflected in our rate case, if it would cause our average common equity ratio, on a financial basis, to fall below our authorized level of 49.5%. A return of capital in excess of the test year amount can be paid by us at the end of the year provided that our average common equity ratio does not fall below the authorized level.

See Note 7, Short-Term Debt and Lines of Credit, for discussion of certain financial covenants related to our short-term debt obligations.

Our regulated member's equity is lower than our GAAP equity as it includes adjustments for purchase accounting and other factors. As of December 31, 2018, approximately $737 million of our regulated member's equity, on a financial basis, was restricted.

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

NOTE 7—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	**$ 277.3**	$ 205.9
Average interest rate on amounts outstanding at December 31	**2.76%**	1.71%

Our average amount of commercial paper borrowings based on daily outstanding balances during 2018 was $184.8 million, with a weighted-average interest rate during the period of 2.23%.

We have entered into a bank back-up credit facility to maintain short term credit liquidity which, among other terms, requires us to maintain, subject to certain exclusions, a total funded debt to capitalization ratio of 65% or less. As of December 31, 2018, we were in compliance with our financial covenants.

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

(in millions)	Maturity	2018
Revolving credit facility	October 2022	**$ 350.0**
Less:		
Commercial paper outstanding		**277.3**
Available capacity under existing agreement		**$ 72.7**

This facility has a renewal provision for two one-year extensions, subject to lender approval.

Our bank back-up credit facility contains customary covenants, including certain limitations on our ability to sell assets. The credit facility also contains 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.

NOTE 8—LONG-TERM DEBT

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

The following table shows the future maturities of our long-term debt outstanding as of December 31, 2018:

(in millions)	Payments
2019	$ —
2020	—
2021	—
2022	—
2023	—
Thereafter	490.0
Total	$ 490.0

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

Our long-term debt obligations contain covenants related to payment of principal and interest when due and various other obligations. Failure to comply with these covenants could result in an event of default, which could result in the acceleration of outstanding debt obligations.

NOTE 9—INCOME TAXES

Income Tax Expense

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

(in millions)	2018	2017
Current tax expense	**$ 9.5**	$ 19.9
Deferred income taxes, net	**15.3**	40.8
Total income tax expense	**$ 24.8**	$ 60.7

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	
(in millions)	Amount	Effective Tax Rate	Amount	Effective Tax Rate
Expected tax at statutory federal tax rates	**$ 21.0**	**21.0 %**	$ 39.9	35.0 %
State income taxes net of federal tax benefit	**6.2**	**6.2 %**	5.8	5.1 %
Federal excess deferred tax amortization	**(2.3)**	**(2.3)%**	—	— %
Tax Legislation	**—**	**— %**	15.1	13.3 %
Other, net	**(0.1)**	**(0.1)%**	(0.1)	(0.1)%
Total income tax expense	**$ 24.8**	**24.8 %**	$ 60.7	53.3 %

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 net tax benefit related to the remeasurement of our deferred taxes in the amount of $175 million. Accordingly, the tax benefit related to our regulated operations was recorded as both an increase to regulatory liabilities as well as a decrease to certain existing regulatory assets at December 31, 2017. The effects of the Tax Legislation related to certain non-regulated items resulted in the recording of income tax expense in the amount of $15.1 million for the year ended December 31, 2017. This amount was primarily due to a re-measurement of deferred tax assets and liabilities.

On December 22, 2017, the Securities and Exchange Commission 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, analyzed the impact on Alternative Minimum Tax Credit carryforwards, 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 at December 31 were as follows:

(in millions)	2018	2017
Deferred tax assets		
Tax gross up – regulatory items	**$ 51.6**	$ 46.6
Uncollectible account expense	**8.8**	10.0
Construction advances	**1.6**	2.2
Inventory	**1.1**	1.2
Employee benefits and compensation	**1.1**	0.9
Future tax benefits	**0.3**	0.9
Other	**7.3**	2.8
Total deferred tax assets	**$ 71.8**	$ 64.6
Deferred tax liabilities		
Property-related	**$ 185.4**	$ 169.6
Pension benefits	**64.1**	64.0
Post-retirement benefits	**21.9**	21.0
Other	**3.6**	2.6
Total deferred tax liabilities	**$ 275.0**	$ 257.2
Deferred tax liability, net	**$ 203.2**	$ 192.6

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

At December 31, 2018, we had $0.1 million of federal tax benefit carryforwards resulting in deferred tax assets of $0.1 million. These federal tax benefit carryforwards expire in 2022. We expect to have future taxable income sufficient to utilize these deferred tax assets. At December 31, 2017, we had $1.2 million and $0.1 million of federal charitable contribution and tax credit carryforwards resulting in deferred tax assets of $0.3 million and $0.1 million, respectively.

At December 31, 2018, we had $4.3 million of state net operating loss carryforwards resulting in deferred tax assets of $0.2 million. These state net operating loss carryforwards begin to expire in 2035. We expect to have future taxable income sufficient to utilize these deferred tax assets. At December 31, 2017, we had $6.5 million and $2.1 million of state charitable contribution and state net operating loss carryforwards resulting in deferred tax assets of $0.4 million and $0.1 million, respectively.

Unrecognized Tax Benefits

We had no unrecognized tax benefits at December 31, 2018 and 2017.

We do not expect any unrecognized tax benefits to affect our effective tax rate in periods after December 31, 2018.

For the years ended December 31, 2018 and 2017, we recognized no interest and no penalties related to unrecognized tax benefits in our income statements. At December 31, 2018 and 2017, we had no interest accrued and no penalties accrued related to unrecognized tax benefits on our balance sheets.

We do not anticipate any significant increases in the total amounts of unrecognized tax benefits within the next 12 months.

Our primary tax jurisdictions include federal and the state of Wisconsin. With a few exceptions, we are no longer subject to federal income tax examinations by the United States Internal Revenue Service for years prior to 2015. At December 31, 2018, we were subject to examination by the Wisconsin taxing authority for tax years 2014 through 2018.

NOTE 10—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	**$ 0.4**	**$ 0.1**	**$ —**	**$ 0.5**
Derivative liabilities				
Natural gas contracts	**0.4**	**0.2**	**—**	**0.6**

	December 31, 2017			
(in millions)	Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	$ 0.3	$ 0.4	$ —	$ 0.7
Derivative liabilities				
Natural gas contracts	0.9	0.1	—	1.0

The derivative assets and liabilities listed in the tables above include natural gas purchase contracts, options, and futures used to manage volatility in natural gas supply costs. See Note 11, Derivative Instruments, for more information.

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
Long-term debt	**$ 486.3**	**$ 479.8**	$ 486.0	$ 513.8

The fair value of long-term debt is categorized within Level 2 of the fair value hierarchy.

NOTE 11—DERIVATIVE INSTRUMENTS

The following table shows our derivative assets and derivative liabilities, none of which are designated as hedging instruments.

	December 31, 2018		December 31, 2017	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Other current				
Natural gas contracts	**$ 0.5**	**$ 0.6**	$ 0.7	$ 0.9
Other long-term				
Natural gas contracts	**—**	**—**	—	0.1
Total	**$ 0.5**	**$ 0.6**	$ 0.7	$ 1.0

Realized gains and losses on derivative instruments are primarily recorded in cost of natural gas sold on our income statements. Our estimated notional sales volumes and realized gains and losses were as follows for the years ended:

	December 31, 2018		December 31, 2017	
(in millions)	Volume	Gains	Volume	Losses
Natural gas contracts	23.8 Dth	**$ 3.0**	19.0 Dth	$ (1.1)

At December 31, 2018 and 2017, we had posted cash collateral of $0.5 million and $1.8 million, respectively, in our margin accounts.

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	**$ 0.5**	**$ 0.6**	$ 0.7	$ 1.0
Gross amount not offset on the balance sheet	**(0.4)**	**(0.4)**	(0.3)	(0.9) *
Net amount	**$ 0.1**	**$ 0.2**	$ 0.4	$ 0.1

* Includes cash collateral posted of $0.6 million.

NOTE 12—EMPLOYEE BENEFITS

Pension and Other Postretirement Employee Benefits

We participate in WEC Energy Group's defined benefit pension plans and OPEB plans that cover substantially all of our employees. We are responsible for our share of the plan assets and obligations. The benefits for a portion of these plans are funded through irrevocable trusts, as allowed for income tax purposes. Our balance sheets reflect only the liabilities associated with our past and current employees and our share of the plan assets and obligations. 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, employees who started with us after 1997 receive a benefit based on a percentage of their annual salary plus an interest credit, while employees who started before 1998 receive a benefit based upon years of service and final average salary. New management employees hired after December 31, 2014 receive an annual company contribution to their 401(k) savings plan instead of being enrolled in the defined benefit plans. In October 2017, we remeasured the obligations of our OPEB plan as a result of a plan design change to move all participants to the same Medicare Advantage plan design starting January 1, 2018.

We use a year-end measurement date to measure the funded status of all of the 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 the pension and OPEB plans qualify as a regulatory asset.

The following table shows information relating to our share of the plans' benefit obligations and fair value of assets. Amounts presented are as of December 31:

	Pension Costs		OPEB Costs	
(in millions)	2018	2017	2018	2017
Benefit obligation	**$ 136.6**	$ 148.6	**$ 55.7**	$ 69.6
Fair value of plan assets	**232.1**	248.3	**112.8**	120.3
Funded status	**$ 95.5**	$ 99.7	**$ 57.1**	$ 50.7

The amount of contributions and benefit payments for the years ended December 31 was as follows:

	Pension Costs		OPEB Costs	
(in millions)	2018	2017	2018	2017
Employer contributions	**$ 1.0**	$ 1.0	**$ 2.2**	$ 1.7
Participant contributions	**—**	—	**0.4**	0.6
Benefit payments	**(11.5)**	(11.2)	**(5.4)**	(4.0)

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

	Pension Costs		OPEB Costs	
(in millions)	2018	2017	2018	2017
Prepaid pension and OPEB costs	**$ 111.9**	$ 111.6	**$ 57.1**	$ 50.7
Other long-term liabilities	**16.4**	11.9	**—**	—
Total net assets	**$ 95.5**	$ 99.7	**$ 57.1**	$ 50.7

The accumulated benefit obligation for all defined benefit plans was $136.6 million and $148.6 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. There were no plan assets related to these pension plans. Amounts presented are as of December 31:

(in millions)	2018	2017
Projected benefit obligation	**$ 38.3**	$ 11.9
Accumulated benefit obligation	**38.3**	11.9
Fair value of plan assets	**21.9**	—

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
Net regulatory assets				
Net actuarial loss	**$ 140.3**	$ 134.6	**$ 24.5**	$ 23.5
Prior service credits	**(0.3)**	(0.3)	**(0.1)**	(0.2)
Total	**$ 140.0**	$ 134.3	**$ 24.4**	$ 23.3

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	$ 8.5	$ —
Total 2019 – estimated amortization	$ 8.5	$ —

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

	Pension Costs		OPEB Costs	
(in millions)	2018	2017	2018	2017
Net periodic benefit (credits) costs	**$ (0.5)**	$ 1.2	**$ (5.4)**	$ (4.6)

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 and 2017, 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 statement for the year ended December 31, 2017, was retroactively restated from what was previously presented in our 2017 Annual Report. The impacts to our income statement from adoption of this standard are reflected in the table below.

	Year Ended December 31, 2017		
(in millions)	2017 Annual Report Income Statement	Impact of ASU 2017-07	Income Statement After Adoption
Operating expenses			
Other operation and maintenance	$ 108.8	$ 5.4	$ 114.2
Other expense			
Other income, net	1.5	5.4	6.9

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 benefit obligations for the plans were as follows for the years ended December 31:

	Pension		OPEB	
	2018	**2017**	**2018**	**2017**
Discount rate	**4.29%**	3.64%	**4.30%**	3.65%
Rate of compensation increase	**3.40%**	3.20%	**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	**6.11%**	6.18%
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 net periodic benefit cost for the plans were as follows for the years ended December 31:

	Pension Costs	
	2018	**2017**
Discount rate	**3.64%**	4.09%
Expected return on assets	**7.00%**	7.00%
Rate of compensation increase	**3.40%**	3.20%

	OPEB Costs	
	2018	**2017**
Discount rate	**3.65%**	4.10%
Expected return on assets	**7.25%**	7.25%
Assumed medical cost trend rate (Pre 65)	**6.50%**	7.00%
Ultimate trend rate (Pre 65)	**5.00%**	5.00%
Year ultimate trend rate is reached (Pre 65)	**2024**	2021
Assumed medical cost trend rate (Post 65)	**6.18%**	7.00%
Ultimate trend rate (Post 65)	**5.00%**	5.00%
Year ultimate trend rate is reached (Post 65)	**2028**	2021

WEC Energy Group consults with its investment advisors on an annual basis to help 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 7.00% for the pension plans and 7.25% for the OPEB plans.

Plan Assets

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

The Investment Trust Policy Committee oversees investment matters related to all of our funded benefit plans. The Committee works with external actuaries and investment consultants on an on-going basis to establish and monitor investment strategies and target asset allocations. Forecasted cash flows for plan liabilities are regularly updated based on annual valuation results. Target allocations are determined using projected benefit payments 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.

Our pension plan's assets are invested in a corporate pension trust with a target asset allocation of 35% equity investments, 55% fixed income investments, and 10% private equity and real estate investments. Our two OPEB trusts have target asset allocations of 50% equity investments and 50% fixed income investments, and 70% equity investments and 30% fixed income investments, 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(m), 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 table summarizes the fair values of our investments by asset class:

	As of 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	**$ 20.2**	**$ —**	**$ —**	**$ 20.2**	**$ 13.9**	**$ —**	**$ —**	**$ 13.9**
International Equity	**19.5**	**—**	**—**	**19.5**	**13.6**	**—**	**—**	**13.6**
Fixed income securities: *								
United States Bonds	**15.1**	**99.3**	**—**	**114.4**	**13.9**	**25.9**	**—**	**39.8**
International Bonds	**1.9**	**7.2**	**—**	**9.1**	**0.9**	**1.6**	**—**	**2.5**
	$ 56.7	**$ 106.5**	**$ —**	**$ 163.2**	**$ 42.3**	**$ 27.5**	**$ —**	**$ 69.8**
Investments measured at net asset value				**$ 68.9**				**$ 43.0**
Total	**$ 56.7**	**$ 106.5**	**$ —**	**$ 232.1**	**$ 42.3**	**$ 27.5**	**$ —**	**$ 112.8**

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

	As of December 31, 2017							
	Pension Plan Assets				OPEB Assets			
(in millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Asset Class								
Cash and cash equivalents	$ —	$ 1.5	$ —	$ 1.5	$ 1.2	$ 0.2	$ —	$ 1.4
Equity securities:								
United States Equity	24.0	—	—	24.0	16.0	—	—	16.0
International Equity	25.0	—	—	25.0	17.7	—	—	17.7
Fixed income securities: *								
United States Bonds	16.6	102.4	—	119.0	13.4	24.9	—	38.3
International Bonds	2.1	7.2	—	9.3	0.9	1.5	—	2.4
Private Equity and Real Estate	—	4.5	12.1	16.6	—	0.8	2.0	2.8
	$ 67.7	$ 115.6	$ 12.1	$ 195.4	$ 49.2	$ 27.4	$ 2.0	$ 78.6
Investments measured at net asset value				$ 52.9				$ 41.7
Total	$ 67.7	$ 115.6	$ 12.1	$ 248.3	$ 49.2	$ 27.4	$ 2.0	$ 120.3

* 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:

	Private Equity and Real Estate	
(in millions)	**Pension**	**OPEB**
Beginning balance at January 1, 2018	**$ 12.1**	**$ 2.0**
Realized and unrealized gains	**1.4**	**0.3**
Purchases	**2.2**	**0.4**
Liquidations	**(0.2)**	**—**
Transfers out of level 3	**(15.5)**	**(2.7)**
Ending balance at December 31, 2018	**$ —**	**$ —**

	Private Equity and Real Estate	
(in millions)	**Pension**	**OPEB**
Beginning balance at January 1, 2017	$ 2.3	$ 0.4
Realized and unrealized gains	0.5	0.1
Purchases	4.9	0.8
Transfers into level 3	4.4	0.7
Ending balance at December 31, 2017	$ 12.1	$ 2.0

Cash Flows

We expect to contribute $1.1 million to the pension plans in 2019, dependent upon various factors affecting us, including our liquidity position and the effects of the new Tax Legislation. We expect to contribute an insignificant amount to the OPEB plans in 2019.

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

(in millions)	**Pension**	**OPEB**
2019	$ 11.5	$ 4.2
2020	10.6	4.6
2021	11.0	4.7
2022	10.2	4.6
2023	9.2	4.6
2024-2028	42.0	18.4

Savings Plans

WEC Energy Group sponsors a 401(k) savings plan which allows substantially all of our full-time 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 plan includes an Employee Stock Ownership Plan. Certain employees receive an employer retirement contribution, which amounts are contributed to an employee's savings plan account. Total costs incurred under all of these plans were $1.5 million and $1.3 million in 2018 and 2017, respectively.

NOTE 13—COMMITMENTS AND CONTINGENCIES

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

Unconditional Purchase Obligations

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

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

(in millions)	Date Contracts Extend Through	Total Amounts Committed	Payments Due By Period					
			2019	2020	2021	2022	2023	Later Years
Natural gas supply and transportation	**2048**	**$ 666.6**	**$ 103.3**	**$ 73.9**	**$ 51.1**	**$ 36.4**	**$ 30.2**	**$ 371.7**

Environmental Matters

Consistent with other companies in the natural gas utility 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 greenhouse gas emissions 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 protection of wetlands and waterways, threatened and endangered species, and cultural resources associated with utility construction projects;
- the reporting of CO_2 emissions to comply with federal clean air rules; and
- the remediation of former manufactured gas plant sites.

Air Quality

Environmental Protection Agency Greenhouse Gases Reporting Program

We are required to report our CO_2 equivalent emissions related to the natural gas that we distribute and sell under the EPA Greenhouse Gases Reporting Program. For 2017, we reported CO_2 equivalent emissions of approximately 5.8 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 6.3 million metric tonnes to the EPA for 2018.

Land Quality

Manufactured Gas Plant Remediation

We have identified sites at which we 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. We are responsible for the environmental remediation of these sites. We are also working with the Wisconsin Department of Natural Resources and the EPA on our investigation and remediation planning. These sites are at various stages of investigation, monitoring, remediation, and closure.

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	**$ 85.6**	$ 47.3
Reserves for future remediation	**77.7**	41.2

Enforcement and Litigation Matters

We 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.

NOTE 14—SUPPLEMENTAL CASH FLOW INFORMATION

(in millions)	2018	2017
Cash (paid) for interest, net of amount capitalized	**$ (24.5)**	$ (21.6)
Cash (paid) received for income taxes, net	**(18.9)**	5.0
Significant non-cash transactions:		
Accounts payable related to construction costs	**3.3**	—

NOTE 15—REGULATORY ENVIRONMENT

Tax Cuts and Jobs Act of 2017

In December 2017, we deferred for return to ratepayers, through future refunds or bill credits, the estimated tax benefit of $190 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.

In May 2018, the PSCW issued an order regarding the benefits associated with the Tax Legislation. The PSCW order requires 100% of the current 2018 and 2019 tax benefits be returned to our 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 being deferred. The timing and method of returning the remaining net tax benefit associated with the revaluation of deferred taxes was not addressed and will be determined in a future rate proceeding.

2018 and 2019 Rates

During April 2017, we, along with WE and WPS, filed an application with the PSCW for approval of a settlement agreement we made with several of our 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 our natural gas customers. Based on the PSCW order, our authorized ROE remains at 10.3%, and our current capital cost structure will remain unchanged through 2019.

Pursuant to the settlement agreement, we also agreed to keep our earnings sharing mechanism in place through 2019. Under this earnings sharing mechanism, if we earn above our 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 anticipate initiating a rate proceeding with the PSCW by April 1, 2019.

Natural Gas Storage Facilities in Michigan

In January 2017, WEC Energy Group signed an agreement for the acquisition of Bluewater. Bluewater owns natural gas storage facilities in Michigan that provide a portion of the current storage needs for our natural gas utility operations. As a result of this agreement, we, along with WE 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 requested that the PSCW review and confirm the reasonableness and prudency of our potential long-term storage service agreement and interstate natural gas transportation contract related to the storage facilities. We, along with WE and WPS, also requested approval to amend WEC Energy Group's AIA to ensure WBS and WEC Energy Group's other subsidiaries could provide services to the storage facilities. During June 2017, the PSCW granted, subject to various conditions, these declarations and approvals, and WEC Energy Group acquired Bluewater on June 30, 2017. In September 2017, we entered into the long-term service agreement for the natural gas storage, which was then approved by the PSCW in November 2017.

NOTE 16—OTHER INCOME, NET

Total other income, net was as follows for the years ended December 31:

(in millions)	2018	2017
Non-service components of net periodic benefit costs	**0.4**	5.4
AFUDC – Equity	**0.6**	0.9
Other, net	**0.9**	0.6
Total other income, net	**$ 1.9**	$ 6.9

NOTE 17—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 and did not identify any leases that were significant, 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 annual report for the year ended December 31, 2019.

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.
- 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 Accounting Standards Codification 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. We do not expect the adoption of Topic 842 to result in us recording any significant right of use assets or related lease liabilities related to operating leases, and we had no capital leases upon adoption. 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 beginning after December 15, 2021, including interim periods within those fiscal years. 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. This guidance is effective for fiscal years beginning after December 15, 2020, and interim periods within fiscal years beginning after December 15, 2021. 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 financial statements.

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2018

OR

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

For the transition period from _____ to _____

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	IRS Employer Identification No.
1-3016	**WISCONSIN PUBLIC SERVICE CORPORATION** (A Wisconsin Corporation) 700 North Adams Street P. O. Box 19001 Green Bay, WI 54307-9001 800-450-7260	39-0715160

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

None

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

None

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

Yes [ ] No [X]

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

Yes [ ] No [X]

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes [X] No [ ]

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).

Yes [X] No [ ]

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

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

Large accelerated filer [ ]	Accelerated filer [ ]
Non-accelerated filer [X]	Smaller reporting company [ ]
	Emerging growth company [ ]

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

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes [ ] No [X]

As of June 30, 2018 (and currently), all of the common stock of Wisconsin Public Service Corporation is held by Integrys Holding, Inc., a wholly owned subsidiary of WEC Energy Group, Inc.

State the aggregate market value of the voting and non-voting common equity held by non-affiliates of the Registrant.

None.

Number of shares outstanding of each class of common stock, as of January 31, 2019

Common Stock, $4 par value, 23,896,962 shares outstanding

The Registrant meets the conditions set forth in General Instructions I(1)(a) and (b) of Form 10-K and is therefore filing with the reduced disclosure format set forth in General Instruction I(2).

WISCONSIN PUBLIC SERVICE CORPORATION
ANNUAL REPORT ON FORM 10-K
For the Year Ended December 31, 2018
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GLOSSARY OF TERMS AND ABBREVIATIONS

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

Subsidiaries and Affiliates	
ATC	American Transmission Company LLC
Bluewater	Bluewater Natural Gas Holding, LLC
Integrys	Integrys Holding, Inc.
UMERC	Upper Michigan Energy Resources Corporation
WBS	WEC Business Services LLC
WE	Wisconsin Electric Power Company
WEC Energy Group	WEC Energy Group, Inc.
WG	Wisconsin Gas LLC
WPS Leasing	WPS Leasing, Inc.
WPSI	WPS Investments, LLC
WRPC	Wisconsin River Power Company

Federal and State Regulatory Agencies	
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	United States Internal Revenue Service
MPSC	Michigan Public Service 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
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
MW	Megawatt
MWh	Megawatt-hour

Other Terms and Abbreviations

AIA	Affiliated Interest Agreement
ARR	Auction Revenue Right
Compensation Committee	Compensation Committee of the Board of Directors of WEC Energy Group, Inc.
D.C. Circuit Court of Appeals	United States Court of Appeals for the District of Columbia Circuit
Exchange Act	Securities Exchange Act of 1934, as amended
FTR	Financial Transmission Right
GCRM	Gas Cost Recovery Mechanism
LMP	Locational Marginal Price
MISO	Midcontinent Independent System Operator, Inc.
MISO Energy Markets	MISO Energy and Operating Reserves Market
NYMEX	New York Mercantile Exchange
Omnibus Stock Incentive Plan	WEC Energy Group 1993 Omnibus Stock Incentive Plan, Amended and Restated Effective as of January 1, 2016
ROE	Return on Equity
RTO	Regional Transmission Organization
SMRP	System Modernization and Reliability Project
Supreme Court	United States Supreme Court
Tax Legislation	Tax Cuts and Jobs Act of 2017

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, effective tax rates, pension and OPEB plans, fuel costs, sources of electric energy supply, coal and natural gas deliveries, remediation costs, environmental matters, liquidity and capital resources, and other matters.

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

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

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

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

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

- The timely completion of capital projects within budgets, as well as the recovery of the related costs through rates;

- The impact of federal, state, and local legislative and/or regulatory changes, including changes in rate-setting policies or procedures, deregulation and restructuring of the electric and/or natural gas utility industries, transmission or distribution system operation, the approval process for new construction, reliability standards, pipeline integrity and safety standards, allocation of energy assistance, energy efficiency mandates, and tax laws that affect our ability to use production tax credits and investment tax credits;

- The remaining uncertainty surrounding the Tax Legislation enacted in December 2017, including implementing regulations and IRS interpretations, the amount to be returned to our ratepayers, and its impact, if any, on our 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 WEC Energy Group's 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 or us;
- Costs and effects of litigation, administrative proceedings, investigations, settlements, claims, and inquiries;
- 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 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;
- Potential business strategies to acquire and dispose of assets or businesses, which cannot be assured to be completed timely or within budgets;
- 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 WEC Energy Group's enterprise systems with those of its other utilities;
- 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.

PART I

ITEM 1. BUSINESS

A. INTRODUCTION

In this report, when we refer to "us," "we," "our," or "ours," we are referring to Wisconsin Public Service Corporation. The term "utility" refers to our regulated activities, while the term "non-utility" refers to our activities that are not regulated, as well as the activities of our former subsidiary, WPS Leasing, which was dissolved in July 2016. References to "Notes" are to the Notes to the Consolidated Financial Statements included in this Annual Report on Form 10-K.

We are an indirect wholly owned subsidiary of WEC Energy Group and were incorporated in the state of Wisconsin in 1883. We serve customers in northeastern Wisconsin and served customers in Michigan's Upper Peninsula through December 31, 2016. Effective January 1, 2017, we transferred our electric and natural gas customers and distribution assets located in the Upper Peninsula of Michigan to UMERC, a stand-alone utility owned by WEC Energy Group. Effective January 1, 2017, we transferred our ownership interest in WPSI to another subsidiary of Integrys. See Note 3, Related Parties, for more information on UMERC and WPSI. Our two reportable segments are utility and other.

For more information about our utility operations, including financial and geographic information, see Note 18, Segment Information, and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations.

Available Information

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

B. UTILITY SEGMENT

ELECTRIC UTILITY OPERATIONS

We generate and distribute electric energy to customers located in northeastern and central Wisconsin.

Through December 31, 2016, we served electric customers in the Upper Peninsula of Michigan. Effective January 1, 2017, we transferred our electric customers and electric distribution assets located in the Upper Peninsula of Michigan to UMERC, a stand-alone utility owned by WEC Energy Group. See Note 3, Related Parties, for more information. UMERC currently meets its market obligations through power purchase agreements with us and WE. UMERC will begin to generate electricity when its new generation solution in the Upper Peninsula of Michigan begins commercial operation, which is expected to occur during the second quarter of 2019.

Operating Revenues

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

	Year Ended December 31	
(in millions)	**2017**	**2016**
Operating revenues		
Residential	$ 369.5	$ 377.4
Small commercial and industrial	367.9	372.0
Large commercial and industrial	239.3	250.2
Other	8.6	8.8
Total retail revenues	985.3	1,008.4
Wholesale	161.4	142.7
Resale	32.6	22.7
Other operating revenues *	22.6	13.9
Total operating revenues	$ 1,201.9	$ 1,187.7

* Includes amounts collected from customers for certain fuel and purchased power costs that exceed a 2% price variance from the costs included in rates.

Electric Sales

Our electric energy deliveries included supply and distribution sales to retail and wholesale customers. In 2018, retail electric revenues accounted for 84.2% of total electric operating revenues, while wholesale and resale electric revenues accounted for 14.8% of total electric operating revenues. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Utility Segment Contribution to Operating Income for information on MWh sales by customer class.

We are authorized to provide retail electric service in designated territories in the state of Wisconsin, as established by indeterminate permits and boundary agreements with other utilities.

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

Electric Sales Forecast

Our service territory experienced growth in weather-normalized retail electric sales in 2018 due to customer growth. We currently forecast retail electric sales volumes and the associated peak demand to grow between flat and 0.5% over the next five years, assuming normal weather.

Customers

	Year Ended December 31		
(in thousands)	**2018**	**2017**	**2016**
Electric customers – end of year			
Residential	**392.2**	389.5	395.7
Small commercial and industrial	**54.1**	53.8	54.4
Large commercial and industrial	**0.2**	0.2	0.2
Other	**—**	—	0.1
Total electric customers – end of year	**446.5**	443.5	450.4

Large Electric Retail Customers

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

Wholesale Customers

We provide wholesale electric service to various customers, including electric cooperatives, municipal joint action agencies, other investor-owned utilities, municipal utilities, and energy marketers. Wholesale sales accounted for 17.6%, 19.2%, and 18.1% of total electric energy sales volumes during 2018, 2017, and 2016, respectively. Wholesale revenues accounted for 11.6%, 13.4%, and 12.0% of total electric operating revenues during 2018, 2017, and 2016, respectively.

Resale

The majority of our sales for resale are sold into an energy market operated by MISO at market rates based on availability of our generation and market demand. Resale sales accounted for 7.4%, 5.9%, and 3.4% of total electric energy sales volumes during 2018, 2017, and 2016, respectively. Resale revenues accounted for 3.2%, 2.7%, and 1.9% of total electric operating revenues during 2018, 2017, and 2016, respectively. Retail fuel costs are reduced by the amount that revenue exceeds the costs of sales derived from these opportunity sales.

Electric Generation and Supply Mix

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

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

	Rated Capacity in MW [1]		
	2018	**2017**	**2016**
Coal	**1,029**	1,336	1,351
Natural gas:			
Combined cycle	**567**	571	557
Steam turbine [2]	**78**	74	80
Natural gas/oil peaking units [3]	**455**	476	451
Renewables [4]	**75**	82	83
Total rated capacity	**2,204**	2,539	2,522

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

[2] The natural gas steam turbine represents the rated capacity associated with Weston Unit 2.

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

[4] Includes hydroelectric and wind generation.

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

	Estimate	Actual		
	2019	2018	2017	2016
Company-owned generation units:				
Coal	34.3%	**43.1%**	43.0%	35.2%
Natural gas combined cycle	27.6%	**24.0%**	20.9%	24.3%
Natural gas/oil peaking units	2.8%	**3.6%**	2.5%	1.9%
Renewables	4.7%	**5.1%**	4.8%	5.1%
Total company-owned generation units	69.4%	**75.8%**	71.2%	66.5%
Power purchase contracts:				
Renewables	5.7%	**4.8%**	5.7%	5.1%
Other *	5.5%	**5.4%**	5.4%	7.3%
Total power purchase contracts	11.2%	**10.2%**	11.1%	12.4%
Purchased power from MISO	19.4%	**14.0%**	17.7%	21.1%
Total purchased power	30.6%	**24.2%**	28.8%	33.5%
Total electric utility supply	100.0%	**100.0%**	100.0%	100.0%

* Represents system energy and capacity purchases used to meet customer requirements and certain FERC regulations.

Reshaping our Generation Fleet

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

Coal-Fired Generation

As of December 31, 2018, our coal-fired generation consists of two operating plants with a rated capacity of 1,029 MW. For more information about our operating plants, see Item 2. Properties.

During 2018, we retired 308 MW of coal-fired generation, including the Pulliam power plant and the jointly-owned Edgewater Unit 4, as a result of WEC Energy Group's generation reshaping plan. For more information about the retirement of these plants, see Note 6, Property, Plant, and Equipment.

Natural Gas-Fired Generation

Our natural gas-fired generation consists of five operating plants, including peaking units, with a rated capacity of 1,100 MW as of December 31, 2018. For more information about our operating plants, see Item 2. Properties.

Oil-Fired Generation

We have natural gas-fired peaking units with a rated capacity of 440 MW, which have the ability to burn oil if natural gas is not available due to delivery constraints. For more information about our operating plants, see Item 2. Properties.

Renewable Generation

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

Solar

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

Hydroelectric

Our hydroelectric generating system consists of 17 operating plants with a total installed capacity of 82 MW and a rated capacity of 49 MW as of December 31, 2018. All of our hydroelectric facilities follow FERC guidelines and/or regulations.

Wind

We have two wind sites, consisting of 152 turbines, with an installed capacity of 237 MW and a rated capacity of 26 MW as of December 31, 2018. In April 2018, we, along with two other non-affiliated utilities, completed the purchase of Forward Wind Energy Center, which consists of 86 wind turbines located in Wisconsin with a total capacity of 138 MW. Our proportionate share of Forward Wind Energy Center is 44.6%. See Note 2, Acquisitions, for more information.

Electric System Reliability

The PSCW requires us to maintain a planning reserve margin above our projected annual peak demand forecast to help ensure reliability of electric service to our customers. These planning reserve requirements are consistent with the MISO calculated planning reserve margin. In 2008, the PSCW established a 14.5% reserve margin requirement for long-term planning (planning years two through ten). For short-term planning (planning year one), the PSCW requires Wisconsin utilities to follow the planning reserve margin established by MISO. MISO has a 17.1% installed capacity reserve margin requirement for the planning year from June 1, 2018, through May 31, 2019, and a 16.8% installed capacity reserve margin requirement for the planning year from June 1, 2019, through May 31, 2020. MISO's short-term reserve margin requirements experience year-to-year fluctuations, primarily due to changes in the average forced outage rate of generation within the MISO footprint.

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

Fuel and Purchased Power Costs

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

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

	2018	2017	2016
Coal	**$ 26.19**	$ 25.27	$ 24.56
Natural gas combined cycle	**21.11**	22.32	18.23
Natural gas/oil peaking units	**34.82**	43.70	43.23
Purchased power	**35.13**	34.17	32.99

We purchase coal under long-term contracts, which helps with price stability. In the past, coal and associated transportation services were exposed to volatility in pricing due to changing domestic and world-wide demand for coal and diesel fuel. To moderate the volatility, we were given PSCW approval for a hedging program, which allows us to hedge up to 75% of our potential risks related to

rail transportation fuel surcharge exposure. However, due to decreased volatility over the last few years, we suspended the fuel surcharge hedging program in 2017.

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

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

Coal Supply

We diversify the coal supply for our electric generating facilities and jointly-owned plants by purchasing coal from several mines in Wyoming, as well as from various other states. For 2019, approximately 74% of our total projected coal requirements of 2.4 million tons are contracted under fixed-price contracts. See Note 19, Commitments and Contingencies, for more information on amounts of coal purchases and coal deliveries under contract.

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

(in thousands)	Annual Tonnage
2019	1,812
2020	392

Coal Deliveries

All of our 2019 coal requirements are expected to be shipped by unit trains that we own under existing transportation agreements. The unit trains transport the coal for electric generating facilities from mines in Wyoming. Additional small volume agreements may also be used to supplement the normal coal supply for our facilities.

Midcontinent Independent System Operator Costs

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

Power Purchase Commitments

We enter into short and long-term power purchase commitments to meet a portion of our anticipated electric energy supply needs. Our power purchase commitments with unaffiliated parties are 108 MW per year for 2019 and 2020 and 100 MW per year for 2021 through 2023, which exclude planning capacity purchases. Due to the actual and planned retirement of generation resources, we have entered into purchase agreements to procure additional planning capacity in order to maintain our compliance with planning reserve requirements as established by the PSCW and MISO.

Other Matters

Seasonality

Our electric utility sales are impacted by seasonal factors and varying weather conditions. We sell more electricity during the summer months because of the residential cooling load. We continue to upgrade our electric distribution system, including substations, transformers, and lines, to meet the demand of our customers. Our generating plants performed as expected during the warmest periods of the summer, and all power purchase commitments under firm contract were received. During this period, we did not require public appeals for conservation, and we did not interrupt or curtail service to non-firm customers who participate in load management programs for capacity reasons. However, we did have service curtailments for economic interruptions. Economic interruptions are declared during times in which the price of electricity in the regional market significantly exceeds the cost of

operating the Company's peaking generation. During this time, interruptible customers can choose to continue using electricity at a price based on wholesale market prices.

Competition

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

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

Environmental Matters

For information regarding environmental matters, especially as they relate to coal-fired generating facilities, see Note 19, Commitments and Contingencies.

NATURAL GAS UTILITY OPERATIONS

We are authorized to provide retail natural gas distribution service in designated territories in the state of Wisconsin, as established by indeterminate permits and boundary agreements with other utilities. We also transport customer-owned natural gas. Our natural gas utility provides service to customers located in northeastern Wisconsin and provided service to customers in Michigan's Upper Peninsula through December 31, 2016.

Effective January 1, 2017, we transferred our natural gas customers and natural gas distribution assets located in the Upper Peninsula of Michigan to UMERC, a stand-alone utility. UMERC became operational effective January 1, 2017. See Note 3, Related Parties, for more information.

We provide natural gas utility service to a diversified base of customers in such industries as paper, food products, governmental, financial services, and education. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Utility Segment Contribution to Operating Income for information on natural gas sales volumes by customer class.

Operating Revenues

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

	Year Ended December 31	
(in millions)	**2017**	**2016**
Operating revenues		
Residential	$ 179.1	$ 163.2
Commercial and industrial	90.2	80.0
Total retail revenues	269.3	243.2
Transport	17.9	17.7
Other operating revenues *	(3.7)	(0.4)
Total	$ 283.5	$ 260.5

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

Natural Gas Sales Forecast

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

Customers

(in thousands)	Year Ended December 31 2018	2017	2016
Customers – end of year			
Residential	**295.4**	293.1	295.8
Commercial and industrial	**34.3**	34.0	34.4
Transport	**0.7**	0.7	0.7
Total customers	**330.4**	327.8	330.9

Natural Gas Supply, Pipeline Capacity and Storage

We have been able to meet our contractual obligations with both our suppliers and our customers. For more information on our natural gas utility supply and transportation contracts, see Note 19, Commitments and Contingencies.

Pipeline and Storage Capacity

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

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

In June 2017, WEC Energy Group completed its acquisition of Bluewater. Bluewater owns natural gas storage facilities in Michigan that provide a portion of the current storage needs for our natural gas utility operations. We have entered into a long-term service agreement to take a portion of the storage from Bluewater. See Note 3, Related Parties, for more information on this transaction.

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

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

Combined with our storage capability, management believes that the volume of natural gas under contract is sufficient to meet our forecasted firm peak-day and seasonal demand. Our forecasted design peak-day throughput is 7.0 million therms for the 2018 through 2019 heating season. Our peak daily send-out during 2018 was 6.3 million therms on January 4, 2018.

Natural Gas Supply

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

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

Hedging Natural Gas Supply Prices

We have PSCW approval to hedge up to 60% of planned winter demand and up to 15% of planned summer demand using a mix of NYMEX-based natural gas options and futures contracts. This approval allows us to pass 100% of the hedging costs (premiums, brokerage fees and losses) and proceeds (gains) to customers through our GCRM.

To the extent that opportunities develop and physical supply operating plans are supportive, we also have PSCW approval to utilize NYMEX-based natural gas derivatives to capture favorable forward-market price differentials. That approval provides for 100% of the related proceeds to accrue to our GCRM.

Seasonality

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

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

Competition

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

C. OTHER SEGMENT

Our other segment includes our non-utility activities as well as equity earnings from our investment in WRPC. Prior to January 1, 2017, our other segment also included our equity earnings from our investment in WPSI. WPSI invested in ATC, a for-profit, transmission-only company regulated by the FERC and certain state regulatory commissions. Effective January 1, 2017, we transferred our 10.37% ownership interest in WPSI to another subsidiary of Integrys. See Note 3, Related Parties, for more information.

We own 50% of the stock of WRPC. WRPC owns two hydroelectric plants, and we are entitled to 50% of the total capacity from its plants.

D. REGULATION

In addition to the specific regulations noted below, we are also subject to regulations, where applicable, of the EPA, the WDNR, and the United States Army Corps of Engineers.

Rates

Our retail electric and natural gas rates are regulated by the PSCW, and the FERC regulates our wholesale electric rates. These commissions have general supervisory and regulatory powers over public utilities in their respective jurisdictions. Effective January 1, 2017, we transferred all of our electric and natural gas distribution assets and customers located in the Upper Peninsula of Michigan to UMERC. As a result, we are no longer regulated by the MPSC. See Note 3, Related Parties, for more information about UMERC.

Embedded within our electric rates is an amount to recover fuel and purchased power costs. The Wisconsin retail fuel rules require us to defer, for subsequent rate recovery or refund, any under-collection or over-collection of fuel and purchased power costs that are outside of our symmetrical fuel cost tolerance, which the PSCW typically sets at plus or minus 2% of our approved fuel and purchased power cost plan. Our deferred fuel and purchased power costs are subject to an excess revenues test. If our ROE in a given

year exceeds the ROE authorized by the PSCW, the recovery of under-collected fuel and purchased power costs would be reduced by the amount by which our return exceeds the authorized amount. Prudently incurred fuel and purchased power costs are recovered dollar-for-dollar from our Wisconsin wholesale electric customers.

Our natural gas utility operates under a GCRM as approved by the PSCW. Generally, the GCRM allows for a dollar-for-dollar recovery of prudently incurred natural gas costs.

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

We adopted an earnings sharing mechanism in January 2018 pursuant to our settlement agreement with the PSCW. We will continue to be subject to the earnings sharing mechanism through 2019. See Note 21, Regulatory Environment, for more information on our earnings sharing mechanism and on how our rates are set. Orders from our respective regulators can be viewed at the following websites:

Regulatory Commission	Website
PSCW	https://psc.wi.gov/
FERC	http://www.ferc.gov/

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

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

	2018		2017		2016	
(in millions)	Amount	Percent	Amount	Percent	Amount	Percent
Electric						
Wisconsin	**$ 1,013.6**	**85.0 %**	$ 1,007.9	83.9 %	$ 1,001.5	84.3 %
FERC – Wholesale *	**178.5**	**15.0 %**	194.0	16.1 %	165.4	13.9 %
Michigan *	**—**	**— %**	—	— %	20.8	1.8 %
Total	**1,192.1**	**100.0 %**	1,201.9	100.0 %	1,187.7	100.0 %
Natural Gas						
Wisconsin	**306.4**	**100.0 %**	283.5	100.0 %	257.1	98.7 %
Michigan *	**—**	**— %**	—	— %	3.4	1.3 %
Total	**306.4**	**100.0 %**	283.5	100.0 %	260.5	100.0 %
Total utility operating revenues	**$ 1,498.5**		$ 1,485.4		$ 1,448.2	

* Effective January 1, 2017, we transferred all of our electric and natural gas distribution assets and customers located in the Upper Peninsula of Michigan to UMERC. UMERC currently purchases a portion of its power from us. The revenues received from UMERC are included in the FERC – Wholesale line above. See Note 3, Related Parties, for more information on UMERC.

Electric Transmission, Capacity, and Energy Markets

In connection with its status as a FERC approved RTO, MISO operates bid-based energy markets. MISO has been able to assume significant balancing area responsibilities such as frequency control and disturbance control.

In MISO, base transmission costs are currently being paid by load-serving entities located in the service territories of each MISO transmission owner. The FERC has previously confirmed the use of the current transmission cost allocation methodology. Certain additional costs for new transmission projects are allocated throughout the MISO footprint.

As part of MISO, a market-based platform is used for valuing transmission congestion premised upon the LMP system that is used in certain northeastern and mid-Atlantic states. The LMP system includes the ability to hedge transmission congestion costs through ARRs and FTRs. ARRs are allocated to market participants by MISO, and FTRs are purchased through auctions. A new allocation and

auction were completed for the period of June 1, 2018, through May 31, 2019. The resulting ARR valuation and the secured FTRs are expected to mitigate our transmission congestion risk for that period.

MISO has an annual zonal resource adequacy requirement to ensure there is sufficient generation capacity to serve the MISO market. To meet this requirement, capacity resources can be acquired through MISO's annual capacity auction, bilateral contracts for capacity, or provided from generating or demand response resources. All of our capacity requirements during the planning year from June 1, 2018, through May 31, 2019 were met.

Other Electric Regulations

We are subject to the Federal Power Act and the corresponding regulations developed by certain federal agencies. The Energy Policy Act amended the Federal Power Act in 2005 to, among other things, make electric utility industry consolidation more feasible, authorize the FERC to review proposed mergers and the acquisition of generation facilities, change the FERC regulatory scheme applicable to qualifying cogeneration facilities, and modify certain other aspects of energy regulations and Federal tax policies applicable to us. Additionally, the Energy Policy Act created an Electric Reliability Organization to be overseen by the FERC, which established mandatory electric reliability standards and has the authority to levy monetary sanctions for failure to comply with these standards.

We are subject to Act 141 in Wisconsin which contains certain minimum requirements for renewable energy generation.

All of our hydroelectric facilities follow FERC guidelines and/or regulations.

Other Natural Gas Regulations

Almost all of the natural gas we distribute is transported to our distribution systems by interstate pipelines. The pipelines' transportation and storage services are regulated by the FERC under the Natural Gas Act and the Natural Gas Policy Act of 1978. In addition, the Pipeline and Hazardous Materials Safety Administration and the PSCW are responsible for monitoring and enforcing requirements governing our natural gas safety compliance programs for our pipelines under United States Department of Transportation regulations. These regulations include 49 Code of Federal Regulations (CFR) Part 191 (Transportation of Natural and Other Gas by Pipeline; Annual Reports, Incident Reports, and Safety-Related Condition Reports), 49 CFR Part 192 (Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards), and 49 CFR Part 195 (Transportation of Hazardous Liquids by Pipeline).

We are required to provide natural gas service and grant credit (with applicable deposit requirements) to customers within our service territory. We are generally not allowed to discontinue natural gas service during winter moratorium months to residential heating customers who do not pay their bills. Federal and certain state governments have programs that provide for a limited amount of funding for assistance to our low-income customers.

E. ENVIRONMENTAL COMPLIANCE

Our operations are subject to extensive environmental regulation by state and federal environmental agencies governing air and water quality, hazardous and solid waste management, environmental remediation, and management of natural resources. Costs associated with complying with these requirements are significant. Additional future environmental regulations or revisions to existing laws, including for example, additional regulation of GHG emissions, coal combustion products, air emissions, or wastewater discharges, could significantly increase these environmental compliance costs.

Anticipated expenditures for environmental compliance and remediation issues for the next three years are included in the estimated capital expenditures described in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Capital Requirements. For a discussion of matters related to manufactured gas plant sites and air and water quality, see Note 19, Commitments and Contingencies.

F. EMPLOYEES

As of December 31, 2018, we had 1,189 employees. Local 420 of International Union of Operating Engineers represented 850 of our employees. The current Local 420 collective bargaining agreement expires on April 16, 2021.

ITEM 1A. RISK FACTORS

We are subject to a variety of risks, many of which are beyond our control, that may adversely affect our business, financial condition, and results of operations. You should carefully consider the following risk factors, as well as the other information included in this report and other documents filed by us with the SEC from time to time, when making an investment decision.

Risks Related to Legislation and Regulation

Our business is significantly impacted by governmental regulation and oversight.

We are subject to significant state, local, and federal governmental regulation, including regulation by the PSCW and the FERC. These regulations significantly influence our operating environment, may affect our ability to recover costs from utility customers, and cause us to incur substantial compliance and other costs. Changes in regulations, interpretations of regulations, or the imposition of new regulations could also significantly impact us, including requiring us to change our business operations. Many aspects of our operations are regulated and impacted by government regulation, including, but not limited to: the rates we charge our retail electric and natural gas customers; our authorized rate of return; construction and operation of electric generating facilities and electric and natural gas distribution systems, including the ability to recover such costs; decommissioning generating facilities, the ability to recover the related costs, and continuing to recover the return on the carrying value of these facilities; wholesale power service practices; electric reliability requirements and accounting; participation in the interstate natural gas pipeline capacity market; standards of service; issuance of securities; short-term debt obligations; transactions with affiliates; and billing practices. Failure to comply with any applicable rules or regulations may lead to customer refunds, penalties, and other payments, which could materially and adversely affect our results of operations and financial condition.

The rates we are allowed to charge our customers for retail and wholesale services have the most significant impact on our financial condition, results of operations, and liquidity. Rate regulation provides us an opportunity to recover prudently incurred costs and earn a reasonable rate of return on invested capital. However, our ability to obtain rate adjustments in the future is dependent upon regulatory action, and there is no assurance that our regulators will consider all of our costs to have been prudently incurred. In addition, our rate proceedings may not always result in rates that fully recover our costs or provide for a reasonable ROE. We defer certain costs and revenues as regulatory assets and liabilities for future recovery from or refund to customers, as authorized by our regulators. Future recovery of regulatory assets is not assured, and is subject to review and approval by our regulators. If recovery of regulatory assets is not approved or is no longer deemed probable, these costs would be recognized in current period expense and could have a material adverse impact on our results of operations, cash flows, and financial condition.

We believe we have obtained the necessary permits, approvals, authorizations, certificates, and licenses for our existing operations, have complied with all of their associated terms, and that our business is conducted in accordance with applicable laws. These permits, approvals, authorizations, certificates, and licenses may be revoked or modified by the agencies that granted them if facts develop that differ significantly from the facts assumed when they were issued. In addition, discharge permits and other approvals and licenses are often granted for a term that is less than the expected life of the associated facility. Licenses and permits may require periodic renewal, which may result in additional requirements being imposed by the granting agency. In addition, existing regulations may be revised or reinterpreted by federal, state, and local agencies, or these agencies may adopt new laws and regulations that apply to us. We cannot predict the impact on our business and operating results of any such actions by these agencies.

If we are unable to recover costs of complying with regulations or other associated costs in customer rates in a timely manner, or if we are unable to obtain, renew, or comply with these governmental permits, approvals, authorizations, certificates, or licenses, our results of operations and financial condition could be materially and adversely affected.

We face significant costs to comply with existing and future environmental laws and regulations.

Our operations are subject to numerous federal and state environmental laws and regulations. These laws and regulations govern, among other things, air emissions (including, but not limited to: CO_2, methane, mercury, SO_2, and NOx), water quality, wastewater discharges, and management of hazardous, toxic, and solid wastes and substances. We incur significant costs to comply with these environmental requirements, including costs associated with the installation of pollution control equipment, environmental monitoring, emissions fees, and permits at our facilities. In addition, if we fail to comply with environmental laws and regulations, even if caused by factors beyond our control, that failure may result in the assessment of civil or criminal penalties and fines.

The EPA adopted and implemented (or is in the process of implementing) regulations governing the emission of NOx, SO_2, fine particulate matter, mercury, and other air pollutants under the CAA through the NAAQS, the Mercury and Air Toxics Standards rule, the CPP, the Cross-State Air Pollution Rule, and other air quality regulations. In addition, the EPA finalized regulations under the Clean Water Act that govern cooling water intake structures at our power plants and revised the effluent guidelines for steam electric generating plants. The EPA and the United States Army Corps of Engineers (Army Corps) have also adopted a final rule that would expand traditional federal jurisdiction over navigable waters and related wetlands for permitting and other regulatory matters. However, this rule has been stayed, and the EPA and the Army Corps have proposed revisions to it. We continue to assess the potential cost of complying, and to explore different alternatives in order to comply, with these and other environmental regulations. In addition, as a result of the actions taken by the sitting President and Federal Executive Branch since taking office in January 2017, as well as its announced future plans and other factors, there is uncertainty as to what capital expenditures or additional costs may ultimately be required to comply with existing and future environmental laws and regulations.

Existing environmental laws and regulations may be revised or new laws or regulations may be adopted at the federal or state level that could result in significant additional expenditures for our generation units or distribution systems, including, without limitation, costs to further limit GHG emissions from our operations; operating restrictions on our facilities; and increased compliance costs. In addition, the operation of emission control equipment and compliance with rules regulating our intake and discharge of water could increase our operating costs and reduce the generating capacity of our power plants. Any such regulation may also create substantial additional costs in the form of taxes or emission allowances and could affect the availability and/or cost of fossil fuels.

As a result, certain of our coal-fired electric generating facilities have become uneconomical to maintain and operate, which has resulted in some of these units being retired or converted to an alternative type of fuel. For example, as part of our goal to retire approximately 300 MW of coal-fired generation by 2020, we retired the Pulliam power plant and the jointly-owned Edgewater Unit 4 generating unit during 2018. Certain of our remaining coal-fired electric generating facilities may also be retired or converted in the future. If other generation facility owners in the Midwest retire a significant number of older coal-fired generation facilities, a potential reduction in the region's capacity reserve margin below acceptable risk levels may result. This could impair the reliability of the grid in the Midwest, particularly during peak demand periods. A reduction in available future capacity could also adversely affect our ability to serve our customers' needs.

We are also subject to significant liabilities related to the investigation and remediation of environmental impacts at certain of our current and former facilities and at third-party owned sites. We accrue liabilities and defer costs (recorded as regulatory assets) incurred in connection with our former manufactured gas plant sites. These costs include all costs incurred to date that we expect to recover, management's best estimates of future costs for investigation and remediation, related legal expenses, and are net of amounts recovered by or that may be recovered from insurance or other third parties. Due to the potential for the imposition of stricter standards and greater regulation in the future, the possibility that other potentially responsible parties may not be financially able to contribute to cleanup costs, a change in conditions or discovery of additional contamination, our remediation costs could increase, and the timing of our capital and/or operating expenditures in the future may accelerate or could vary from the amounts currently accrued.

In the event we are not able to recover all of our environmental expenditures and related costs from our customers in the future, our results of operations and financial condition could be adversely affected. Further, increased costs recovered through rates could contribute to reduced demand for electricity and natural gas, which could adversely affect our results of operations, cash flows, and financial condition.

Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental laws and regulations, has increased generally throughout the United States. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by environmental impacts and alleged exposure to hazardous materials have become more frequent. In addition to claims relating to our current facilities, we may also be subject to potential liability in connection with the environmental condition of facilities that we previously owned and operated, regardless of whether the liabilities arose before, during, or after the time we owned or operated these facilities. If we fail to comply with environmental laws and regulations or cause (or caused) harm to the environment or persons, that failure or harm may result in the assessment of civil penalties and damages against us. The incurrence of a material environmental liability or a material judgment in any action for personal injury or property damage related to environmental matters could have a significant adverse effect on our results of operations and financial condition.

We may face significant costs to comply with the regulation of greenhouse gas emissions.

Management believes it is reasonably likely that the scientific and political attention to issues concerning the existence and extent of climate change, and the role of human activity in it, will continue, with the potential for further regulation that affects our operations. In 2015, the EPA issued a final rule regulating GHG emissions from existing generating units, referred to as the CPP, and final performance standards for modified and reconstructed generating units and new fossil-fueled power plants. In February 2016, the Supreme Court stayed the effectiveness of the CPP until disposition of certain litigation in the D.C. Circuit Court of Appeals challenging the rule and, to the extent that further appellate review is sought, at the Supreme Court.

In April 2017, pursuant to motions made by the EPA, the D.C. Circuit Court of Appeals ordered the challenges to the CPP, as well as related performance standards for new, reconstructed, and modified fossil-fueled power plants, be held in abeyance, which remains the case. In August 2018, the EPA issued a proposed replacement rule for the CPP, the ACE rule. The proposed ACE rule would require the EPA to develop emission guidelines for states to use to develop their individual state plans. The state plans would focus on reducing GHG emissions by improving the efficiency of fossil-fueled power plants. In December 2018, the EPA proposed to revise the regulations related to new, modified, and reconstructed fossil-fueled power plants. We are continuing to analyze the GHG emission profile of our electric generation resources and to work with other stakeholders to determine the potential impacts to our operations of the CPP, the proposed ACE rule, and federal GHG regulations in general.

There is no guarantee that we will be allowed to fully recover costs incurred to comply with these and other federal regulations or that cost recovery will not be delayed or otherwise conditioned. GHG regulations that may be adopted in the future, at either the federal or state level, may cause our environmental compliance spending to differ materially from the amounts currently estimated. These regulations, as well as changes in the fuel markets and advances in technology, could make additional electric generating units uneconomic to maintain or operate, may impact how we operate our existing fossil-fueled power plants, and could affect unit retirement and replacement decisions in the future. These regulations could also adversely affect our future results of operations, cash flows, and financial condition.

In addition, our natural gas delivery systems may generate fugitive gas as a result of normal operations and as a result of excavation, construction, and repair. Fugitive gas typically vents to the atmosphere and consists primarily of methane. CO_2 is also a byproduct of natural gas consumption. As a result, future regulation of GHG emissions could increase the price of natural gas, restrict the use of natural gas, and adversely affect our ability to operate our natural gas facilities. A significant increase in the price of natural gas may increase rates for our natural gas customers, which could reduce natural gas demand.

We also continue to monitor efforts by investors and other stakeholders to increase pressure on us and others to take more aggressive action to reduce future GHG emissions in order to limit future global temperature increases to less than two degrees Celsius. These efforts could impact how we operate our electric generating units and natural gas facilities and lead to increased competition and regulation, all of which could have a material adverse effect on our operations and financial condition.

Changes in federal income tax policy may adversely affect our financial condition, results of operations, and cash flows, as well as our credit ratings.

We have invested or will be investing in renewable energy generating facilities, several of which generate production tax credits and investment tax credits that we use to reduce our federal tax obligations. The amount of tax credits we earn depends on the level of electricity generated, the applicable tax credit rate, and the amount of the investment in qualifying property. If our tax credits were disallowed in whole or in part as a results of an IRS audit or changes in tax law, we could owe tax liabilities for previously recognized tax credits that could significantly impact our earnings and cash flows.

In addition, if corporate tax rate or policies are changed with future federal or state legislation, we may be required to take material charges against earnings. For example, the United States federal income tax legislation enacted in December 2017 significantly changed the United States Internal Revenue Code, including taxation of United States corporations, by, among other things, reducing the federal corporate income tax rate, limiting interest deductions, and altering the expensing of capital expenditures. Parts of the Tax Legislation still remain unclear and will require interpretations and implementing regulations by the Treasury Department and the IRS, as well as state income tax authorities, and the Tax Legislation could be subject to potential amendments and technical corrections, any of which could lessen or increase certain adverse impacts of the Tax Legislation. In addition, the regulatory treatment of the impacts of the Tax Legislation will be subject to the discretion of the FERC and the PSCW. State and local taxing authorities continue to evaluate the impact of federal income tax reform, and any changes on the state or local level could lessen or increase the impacts of the Tax Legislation.

There is still uncertainty as to when or how credit rating agencies, capital markets, the FERC, or the PSCW will treat any additional impacts of the Tax Legislation. These impacts could subject us to credit rating downgrades. It is unclear whether additional opportunities may evolve for us to manage the adverse impacts of the Tax Legislation. In addition, certain financial metrics used by credit rating agencies, such as our funds from operations-to-debt percentage, could be negatively impacted by future rulings related to the Tax Legislation.

In addition, the FERC and the PSCW continue to engage with us to determine how certain tax savings will be returned to ratepayers. In December 2017, we deferred the estimated tax benefits for return to ratepayers through bill credits or reductions in regulatory assets. We have received a written order from the PSCW addressing the refunding of certain of these tax benefits to ratepayers in Wisconsin. Despite receiving this written order, the amount of tax benefits we must return to ratepayers could change if the PSCW takes additional action. Furthermore, if the amounts our regulators order us to return to ratepayers exceeds the actual amount of tax savings realized, or our regulators require the tax savings to be applied in a manner other than we had expected, it could have a material adverse effect on our financial condition, results of operations, and cash flow.

While our analysis and interpretation of the Tax Legislation is ongoing, based on our current evaluation, we do not expect the limitations on interest deductions to materially adversely affect our earnings. Any amendments to the Tax Legislation or interpretations or implementing regulations by the Treasury Department and/or the IRS contrary to our interpretation of the Tax Legislation could limit our ability to deduct the interest on some of our outstanding debt.

There may be other material adverse effects resulting from the Tax Legislation that we have not yet identified. If we are unable to successfully take actions to manage any adverse impacts of the Tax Legislation, or if additional interpretations, regulations, amendments, or technical corrections exacerbate the adverse impacts of the Tax Legislation, the Tax Legislation could have an adverse effect on our financial condition, results of operations, cash flows, and on the value of investments in our debt securities, and could result in credit rating agencies placing our credit ratings on negative outlook or downgrading our credit ratings.

Failure to maintain effective internal controls in accordance with Section 404 of the Sarbanes-Oxley Act could have a material effect on our results of operations.

We are subject to reporting, disclosure control, and other obligations under Section 404 of the Sarbanes-Oxley Act (SOX). SOX contains provisions requiring our management to report on the effectiveness of our internal control over financial reporting. We have undertaken, or will undertake, a variety of initiatives to integrate, standardize, centralize, and streamline our operations with technology, including, but not limited to, an enterprise resource planning system and a customer information and billing system. There is a risk that we will not be able to conclude that our internal control over financial reporting is effective because of the discovery of material weaknesses, with either our current controls and processes or with the implementation of new controls and processes around these new technologies. Any failure to maintain effective internal controls could cause investors to lose confidence in the accuracy or completeness of our financial reports, restrict our access to the capital markets, or subject us to investigations by the SEC or other regulatory authorities.

We could be subject to higher costs and penalties as a result of mandatory reliability standards.

We are subject to mandatory reliability and critical infrastructure protection standards established by the North American Electric Reliability Corporation and enforced by the FERC. The critical infrastructure protection standards focus on controlling access to critical physical and cyber security assets. Compliance with the mandatory reliability standards could subject us to higher operating costs. If we were ever found to be in noncompliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties.

Risks Related to the Operation of Our Business

Our operations are subject to risks arising from the reliability of our electric generation, transmission, and distribution facilities, natural gas infrastructure facilities, and other facilities, as well as the reliability of third-party transmission providers.

Our financial performance depends on the successful operation of our electric generation and natural gas and electric distribution facilities. The operation of these facilities involves many risks, including operator error and the breakdown or failure of equipment or processes. Potential breakdown or failure may occur due to severe weather; catastrophic events (i.e., fires, earthquakes, explosions, tornadoes, floods, droughts, pandemic health events, etc.); significant changes in water levels in waterways; fuel supply or transportation disruptions; accidents; employee labor disputes; construction delays or cost overruns; shortages of or delays in

obtaining equipment, material, and/or labor; performance below expected levels; operating limitations that may be imposed by environmental or other regulatory requirements; terrorist attacks; or cyber security intrusions. Any of these events could lead to substantial financial losses.

Because our electric generation facilities are interconnected with third-party transmission facilities, the operation of our facilities could also be adversely affected by events impacting their systems. Unplanned outages at our power plants may reduce our revenues, cause us to incur significant costs if we are required to operate our higher cost electric generators or purchase replacement power to satisfy our obligations, and could result in additional maintenance expenses.

Insurance, warranties, performance guarantees, or recovery through the regulatory process may not cover any or all of these lost revenues or increased expenses, which could adversely affect our results of operations and cash flows.

Our operations are subject to various conditions that can result in fluctuations in energy sales to customers, including customer growth and general economic conditions in our service areas, varying weather conditions, and energy conservation efforts.

Our results of operations and cash flows are affected by the demand for electricity and natural gas, which can vary greatly based upon:

- *Fluctuations in customer growth and general economic conditions in our service areas.* Customer growth and energy use can be negatively impacted by population declines as well as economic factors in our service territories, including workforce reductions, stagnant wage growth, changing levels of support from state and local government for economic development, business closings, and reductions in the level of business investment. We are impacted by economic cycles and the competitiveness of the commercial and industrial customers we serve. Any economic downturn, disruption of financial markets, or reduced incentives by state government for economic development could adversely affect the financial condition of our customers and demand for their products or services. These risks could directly influence the demand for electricity and natural gas as well as the need for additional power generation and generating facilities. We could also be exposed to greater risks of accounts receivable write-offs if customers are unable to pay their bills.
- *Weather conditions*. Demand for electricity is greater in the summer and winter months when cooling and heating is necessary. In addition, demand for natural gas peaks in the winter heating season. As a result, our overall results may fluctuate substantially on a seasonal basis. In addition, milder temperatures during the summer cooling season and during the winter heating season may result in lower revenues and net income.
- *Our customers' continued focus on energy conservation and ability to meet their own energy needs*. Our customers' use of electricity and natural gas has decreased as a result of continued individual conservation efforts, including the use of more energy efficient technologies. Customers could also voluntarily reduce their consumption of energy in response to decreases in their disposable income and increases in energy prices. Conservation of energy can be influenced by certain federal and state programs that are intended to influence how consumers use energy. For example, several states, including Wisconsin, have adopted energy efficiency targets to reduce energy consumption by certain dates.

As part of our planning process, we estimate the impacts of changes in customer growth and general economic conditions, weather, and customer energy conservation efforts, but risks still remain. Any of these matters, as well as any regulatory delay in adjusting rates as a result of reduced sales from effective conservation measures or the adoption of new technologies, could adversely impact our results of operations and financial condition.

We are actively involved with several significant capital projects, which are subject to a number of risks and uncertainties that could adversely affect project costs and completion of construction projects.

Our business requires substantial capital expenditures for investments in, among other things, capital improvements to our electric generating facilities, electric and natural gas distribution infrastructure, and other projects, including projects for environmental compliance. We also expect to invest in renewable energy generating facilities as part of WEC Energy Group's generation reshaping plan.

Achieving the intended benefits of any large construction project is subject to many uncertainties, some of which we will have limited or no control over, that could adversely affect project costs and completion time. These risks include, but are not limited to, the ability to adhere to established budgets and time frames; the availability of labor or materials at estimated costs; the ability of contractors to perform under their contracts; strikes; adverse weather conditions; potential legal challenges; changes in applicable laws or regulations; other governmental actions; continued public and policymaker support for such projects; and events in the global economy. In addition, certain of these projects require the approval of our regulators. If construction of commission-approved

projects should materially and adversely deviate from the schedules, estimates, and projections on which the approval was based, our regulators may deem the additional capital costs as imprudent and disallow recovery of them through rates, and otherwise available production tax credits and investment tax credits for renewable energy projects could be lost.

To the extent that delays occur, costs become unrecoverable, tax credits are lost, or we (or third parties with whom we invest and/or partner) otherwise become unable to effectively manage and complete our (or their) capital projects, our results of operations, cash flows, and financial condition may be adversely affected.

Advances in technology could make our electric generating facilities less competitive.

Advances in new technologies that produce power or reduce power consumption are ongoing and include renewable energy technologies, customer-oriented generation, energy storage devices, and energy efficiency technologies. We generate power at central station power plants to achieve economies of scale and produce power at a competitive cost. There are distributed generation technologies that produce power, including fuel cells, microturbines, wind turbines, and solar cells, which have become more cost competitive than they were in the past. It is possible that legislation or regulations could be adopted supporting the use of these technologies. There is also a risk that advances in technology will continue to reduce the costs of these alternative methods of producing power to a level that is competitive with that of central station power production. If these technologies become cost competitive and achieve economies of scale, our market share could be eroded, and the value of our generating facilities could be reduced. Advances in technology could also change the channels through which our electric customers purchase or use power, which could reduce our sales and revenues or increase our expenses.

Our operations are subject to risks beyond our control, including but not limited to, cyber security intrusions, terrorist attacks, acts of war, or unauthorized access to personally identifiable information.

We have been subject to attempted cyber attacks from time to time, but these attacks have not had a material impact on our system or business operations. Despite the implementation of security measures, all assets and systems are potentially vulnerable to disability, failures, or unauthorized access due to physical or cyber security intrusions caused by human error, vendor bugs, terrorist attacks, or other malicious acts. These threats against our generation facilities, electric and natural gas distribution infrastructure, our information and technology systems, and network infrastructure, including that of third parties on which we rely, could result in a full or partial disruption of our ability to generate, transmit, purchase, or distribute electricity or natural gas or cause environmental repercussions. If our assets or systems were to fail, be physically damaged, or be breached, and were not recovered in a timely manner, we may be unable to perform critical business functions, and data, including sensitive information, could be compromised.

We operate in an industry that requires the use of sophisticated information technology systems and network infrastructure, which control an interconnected system of generation, distribution, and transmission systems shared with third parties. A successful physical or cyber security intrusion may occur despite our security measures or those that we require our vendors to take, which include compliance with reliability standards and critical infrastructure protection standards. Successful cyber security intrusions, including those targeting the electronic control systems used at our generating facilities and electric and natural gas transmission and distribution systems, could disrupt our operations and result in loss of service to customers. These intrusions may cause unplanned outages at our power plants, which may reduce our revenues or cause us to incur significant costs if we are required to operate our higher cost electric generators or purchase replacement power to satisfy our obligations, and could result in additional maintenance expenses. The risk of such intrusions may also increase our capital and operating costs as a result of having to implement increased security measures for protection of our information technology and infrastructure.

Our continued efforts to integrate, consolidate, and streamline our operations have also resulted in increased reliance on current and recently completed projects for technology systems, including an enterprise resource planning system, a customer information and billing system, automated meter reading systems, and other similar technological tools and initiatives. We implement procedures to protect our systems, but we cannot guarantee that the procedures we have implemented to protect against unauthorized access to secured data and systems are adequate to safeguard against all security breaches. The failure of any of these or other similarly important technologies, or our inability to support, update, expand, and/or integrate these technologies with those of our affiliates could materially and adversely impact our operations, diminish customer confidence and our reputation, materially increase the costs we incur to protect against these risks, and subject us to possible financial liability or increased regulation or litigation.

Our business requires the collection and retention of personally identifiable information of our customers and employees, who expect that we will adequately protect such information. Security breaches may expose us to a risk of loss or misuse of confidential and proprietary information. A significant theft, loss, or fraudulent use of personally identifiable information may lead to potentially large costs to notify and protect the impacted persons, and/or could cause us to become subject to significant litigation, costs,

liability, fines, or penalties, any of which could materially and adversely impact our results of operations as well as our reputation with customers and regulators, among others. In addition, we may be required to incur significant costs associated with governmental actions in response to such intrusions or to strengthen our information and electronic control systems. We may also need to obtain additional insurance coverage related to the threat of such intrusions.

Any operational disruption or environmental repercussions caused by these on-going threats to our assets and technology systems could result in a significant decrease in our revenues or significant reconstruction or remediation costs, which could materially and adversely affect our results of operations, financial condition, and cash flows. The costs of repairing damage to our facilities, operational disruptions, protecting personally identifiable information, and notifying impacted persons, as well as related legal claims, may also not be recoverable in rates, may exceed the insurance limits on our insurance policies, or, in some cases, may not be covered by insurance.

Transporting and distributing natural gas involves numerous risks that may result in accidents and other operating risks and costs.

Inherent in natural gas distribution activities are a variety of hazards and operational risks, such as leaks, accidental explosions, and mechanical problems, which could materially and adversely affect our results of operations, financial condition, and cash flows. In addition, these risks could result in serious injury to employees and non-employees, loss of human life, significant damage to property, environmental pollution, impairment of operations, and substantial losses to us. The location of natural gas pipelines near populated areas, including residential areas, commercial business centers, and industrial sites, could increase the level of damages resulting from these risks. These activities may subject us to litigation and/or administrative proceedings from time to time, which could result in substantial monetary judgments, fines, or penalties against us, or be resolved on unfavorable terms.

We may fail to attract and retain an appropriately qualified workforce.

We operate in an industry that requires many of our employees to possess unique technical skill sets. Events such as an aging workforce without appropriate replacements, the mismatch of skill sets to future needs, or the unavailability of contract resources may lead to operating challenges or increased costs. These operating challenges include lack of resources, loss of knowledge, and a lengthy time period associated with skill development. In addition, current and prospective employees may determine that they do not wish to work for us. Failure to hire and obtain replacement employees, including the ability to transfer significant internal historical knowledge and expertise to the new employees, may adversely affect our ability to manage and operate our business. If we are unable to successfully attract and retain an appropriately qualified workforce, our results of operations could be adversely affected.

Failure of our counterparties to meet their obligations, including obligations under power purchase, natural gas supply, and transportation agreements, could have an adverse impact on our results of operations.

We are exposed to the risk that counterparties to various arrangements who owe us money, electricity, natural gas, or other commodities or services will not be able to perform their obligations. Should the counterparties to these arrangements fail to perform, we may be required to replace the underlying commitment at current market prices or we may be unable to meet all of our customers' electric and natural gas requirements unless or until alternative supply arrangements are put in place. In such event, we may incur losses, and our results of operations, financial position, or liquidity could be adversely affected.

We have entered into several power purchase, natural gas supply, and transportation agreements with non-affiliated companies, and continue to look for additional opportunities to enter into these agreements. Revenues are dependent on the continued performance by the counterparties of their obligations under the power purchase, natural gas supply, and transportation agreements. Although we have a comprehensive credit evaluation process and contractual protections, it is possible that one or more counterparties could fail to perform their obligations under these agreements. If this were to occur, we generally would expect that any operating and other costs that were initially allocated to a defaulting customer's power purchase, natural gas supply, or transportation agreement would be reallocated among our retail customers. To the extent these costs are not allowed to be reallocated by our regulators or there is any regulatory delay in adjusting rates, a customer default under these agreements could have a negative impact on our results of operations and cash flows.

Risks Related to Economic and Market Volatility

Our business is dependent on our ability to successfully access capital markets.

We rely on access to credit and capital markets to support our capital requirements, including expenditures for our utility infrastructure and to comply with future regulatory requirements, to the extent not satisfied by the cash flow generated by our operations. We have historically secured funds from a variety of sources, including the issuance of short-term and long-term debt securities. Successful implementation of our long-term business strategies, including capital investment, is dependent upon our ability to access the capital markets, including the banking and commercial paper markets, on competitive terms and rates. In addition, we rely on a committed bank credit agreement as back-up liquidity, which allows us to access the low cost commercial paper markets.

Our access to the credit and capital markets could be limited, or our cost of capital significantly increased, due to any of the following risks and uncertainties:

- A rating downgrade;
- An economic downturn or uncertainty;
- Prevailing market conditions and rules;
- Concerns over foreign economic conditions;
- Changes in tax policy;
- Changes in investment criteria of institutional investors;
- War or the threat of war; and
- The overall health and view of the utility and financial institution industries.

If any of these risks or uncertainties limit our access to the credit and capital markets or significantly increase our cost of capital, it could limit our ability to implement, or increase the costs of implementing, our business plan, which, in turn, could materially and adversely affect our results of operations, cash flows, and financial condition.

A downgrade in our credit ratings could negatively affect our ability to access capital at reasonable costs and/or require the posting of collateral.

There are a number of factors that impact our credit ratings, including, but not limited to, capital structure, regulatory environment, the ability to cover liquidity requirements, and other requirements for capital. We could experience a downgrade in our ratings if the rating agencies determine that the level of business or financial risk of us or the utility industry has deteriorated. Changes in rating methodologies by the rating agencies could also have a negative impact on credit ratings.

Any downgrade by the rating agencies could:

- Increase borrowing costs under our existing credit facility;
- Require the payment of higher interest rates in future financings and possibly reduce the pool of creditors;
- Decrease funding sources by limiting our access to the commercial paper market;
- Limit the availability of adequate credit support for our operations; and
- Trigger collateral requirements in various contracts.

See the risk factor titled "Changes in federal income tax policy may adversely affect our financial condition, results of operations, and cash flows, as well as our credit ratings" above for information about how the Tax Legislation could impact our credit ratings.

Fluctuating commodity prices could negatively impact our electric and natural gas utility operations.

Our operating and liquidity requirements are impacted by changes in the forward and current market prices of natural gas, coal, electricity, renewable energy credits, and ancillary services.

We burn natural gas in several of our electric generation plants, and as a supplemental fuel at several coal-fired plants. In many instances the cost of purchased power is tied to the cost of natural gas. The cost of natural gas may increase because of disruptions in the supply of natural gas due to a curtailment in production or distribution, international market conditions, the demand for natural gas, and the availability of shale gas and potential regulations affecting its accessibility.

For Wisconsin retail electric customers, we bear the risk for the recovery of fuel and purchased power costs within a symmetrical 2% fuel tolerance band compared to the forecast of fuel and purchased power costs established in our rate structure. Prudently incurred fuel and purchased power costs are recovered dollar-for-dollar from our wholesale electric customers. We receive dollar-for-dollar recovery of prudently incurred natural gas costs from our natural gas customers.

Changes in commodity prices could result in:

- Higher working capital requirements, particularly related to natural gas inventory, accounts receivable, and cash collateral postings;
- Reduced profitability to the extent that lower revenues, increased bad debt, and interest expense are not recovered through rates;
- Higher rates charged to our customers, which could impact our competitive position;
- Reduced demand for energy, which could impact revenues and operating expenses; and
- Shutting down of generation facilities if the cost of generation exceeds the market price for electricity.

We may not be able to obtain an adequate supply of coal, which could limit our ability to operate our coal-fired facilities.

We own and operate several coal-fired electric generating units. Although we generally carry sufficient coal inventory at our generating facilities to protect against an interruption or decline in supply, there can be no assurance that the inventory levels will be adequate. While we have coal supply and transportation contracts in place, we cannot assure that the counterparties to these agreements will be able to fulfill their obligations to supply coal to us or that we will be able to take delivery of all the coal volume contracted for. If we are unable to obtain our coal requirements under our coal supply and transportation contracts, we may be required to purchase coal at higher prices or we may be forced to reduce generation at our coal-fired units, which could lead to increased fuel costs. The increase in fuel costs could result in either reduced margins on net sales into the MISO Energy Markets, a reduction in the volume of net sales into the MISO Energy Markets, and/or an increase in net power purchases in the MISO Energy Markets. There is no guarantee that we would be able to fully recover any increased costs in rates or that recovery would not otherwise be delayed, either of which could adversely affect our cash flows.

The use of derivative contracts could result in financial losses.

We use derivative instruments such as swaps, options, futures, and forwards to manage commodity price exposure. We could recognize financial losses as a result of volatility in the market value of these contracts or if a counterparty fails to perform. These risks are managed through risk management policies, which might not work as planned and cannot entirely eliminate the risks associated with these activities. In addition, although our hedging programs must be approved by the PSCW, derivative contracts entered into for hedging purposes might not offset the underlying exposure being hedged as expected, resulting in financial losses. In the absence of actively quoted market prices and pricing information from external sources, the value of these financial instruments can involve management's judgment or use of estimates. Changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

Restructuring in the regulated energy industry and competition in the retail and wholesale markets could have a negative impact on our business and revenues.

The regulated energy industry continues to experience significant structural changes. Increased competition in the retail and wholesale markets, which may result from restructuring efforts, could have a significant adverse financial impact on us.

The FERC continues to support the existing RTOs that affect the structure of the wholesale market within these RTOs. In connection with its status as a FERC approved RTO, MISO implemented bid-based energy markets that are part of the MISO Energy Markets. All market participants, including us, must submit day-ahead and/or real-time bids and offers for energy at locations across the MISO region. MISO then calculates the most efficient solution for all of the bids and offers made into the market that day and establishes an LMP that reflects the market price for energy. We are required to follow MISO's instructions when dispatching generating units to support MISO's responsibility for maintaining the stability of the transmission system. MISO also implemented an ancillary services market for operating reserves that schedules energy and ancillary services at the same time as part of the energy market, allowing for more efficient use of generation assets in the MISO Energy Markets. These market designs continue to have the potential to increase the costs of transmission, the costs associated with inefficient generation dispatching, the costs of participation in the MISO Energy Markets, and the costs associated with estimated payment settlements.

The FERC rules related to transmission are designed to facilitate competition in the wholesale electricity markets among regulated utilities, non-utility generators, wholesale power marketers, and brokers by providing greater flexibility and more choices to wholesale customers, including initiatives designed to encourage the integration of renewable sources of supply. In addition, along with transactions contemplating physical delivery of energy, financial laws and regulations impact hedging and trading based on futures contracts and derivatives that are traded on various commodities exchanges, as well as over-the-counter. Technology changes in the power and fuel industries also have significant impacts on wholesale transactions and related costs. We currently cannot predict the impact of these and other developments or the effect of changes in levels of wholesale supply and demand, which are driven by factors beyond our control.

We may experience poor investment performance of benefit plan holdings due to changes in assumptions and market conditions.

We have significant obligations related to pension and OPEB plans. If WEC Energy Group is unable to successfully manage our benefit plan assets and medical costs, our cash flows, financial condition, or results of operations could be adversely impacted. Our cost of providing these plans is dependent upon a number of factors, including actual plan experience, changes made to the plans, and assumptions concerning the future. Types of assumptions include earnings on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plans, future government regulation, estimated withdrawals by retirees, and our required or voluntary contributions to the plans. Plan assets are subject to market fluctuations and may yield returns that fall below projected return rates. In addition, medical costs for both active and retired employees may increase at a rate that is significantly higher than we currently anticipate. Our funding requirements could be impacted by a decline in the market value of plan assets, changes in interest rates, changes in demographics (including the number of retirements), or changes in life expectancy assumptions.

We may be unable to obtain insurance on acceptable terms or at all, and the insurance coverage we do obtain may not provide protection against all significant losses.

Our ability to obtain insurance, as well as the cost and coverage of such insurance, could be affected by developments affecting our business; international, national, state, or local events; and the financial condition of insurers and our contractors that are required to acquire and maintain insurance for our benefit. Insurance coverage may not continue to be available at all or at rates or terms similar to those presently available to us. In addition, our insurance may not be sufficient or effective under all circumstances and against all hazards or liabilities to which we may be subject. Any losses for which we are not fully insured or that are not covered by insurance at all could materially adversely affect our results of operations, cash flows, and financial position.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

We own our principal properties outright, except that the major portion of our electric utility distribution lines and natural gas utility distribution mains and services are located, for the most part, on or under streets and highways and on land owned by others and are generally subject to granted easements, consents, or permits.

Electric Facilities

The following table summarizes information on our electric generation facilities, including owned and jointly owned facilities, as of December 31, 2018:

Name	Location	Fuel	Number of Generating Units	Rated Capacity In MW [1]
Coal-fired plants				
Columbia	Portage, WI	Coal	2	315 [2]
Weston	Rothschild, WI	Coal	2	714 [2]
Total coal-fired plants			4	1,029
Natural gas-fired plants				
De Pere Energy Center	De Pere, WI	Natural Gas/Oil	1	165
Fox Energy Center	Wrightstown, WI	Natural Gas	3	567
Pulliam	Green Bay, WI	Natural Gas/Oil	1	80
West Marinette	Marinette, WI	Natural Gas/Oil	3	150
Weston	Rothschild, WI	Natural Gas/Oil	3	138
Total natural gas-fired plants			11	1,100
Renewables				
Hydro Plants (17 in number)	WI	Hydro	51	49 [3]
Crane Creek	Howard County, IA	Wind	66	17
Forward Wind Energy Center	Fond du Lac County, WI	Wind	86	9 [4]
Total renewables			203	75
Total system			218	2,204

[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] We jointly own these facilities with various other utilities. The capacity indicated for each of these units is equal to our portion of total plant capacity based on our percent of ownership.

- Wisconsin Power and Light Company, an unaffiliated utility, operates the Columbia units. We hold a 28.1% ownership interest in Columbia. See Note 7, Jointly Owned Utility Facilities, for more information on the decrease in our ownership interest in the Columbia unit.
- We operate the Weston 4 facility and hold a 70.0% ownership interest in this facility. Dairyland Power Cooperative holds the remaining 30.0%.

[3] WRPC owns and operates the Castle Rock and Petenwell units. We hold a 50.0% ownership interest in WRPC and are entitled to 50.0% of the total capacity at Castle Rock and Petenwell. The capacity indicated includes our share of capacity for Castle Rock of 8.4 MW and our share of capacity for Petenwell of 10.2 MW.

[4] In April 2018, we, along with two other unaffiliated utilities, purchased Forward Wind Energy Center, which consists of 86 wind turbines located in Wisconsin with a total capacity of 138 MW. The capacity indicated for the facility is equal to our portion of total plant capacity based on our 44.6% ownership. See Note 2, Acquisitions, for more information on the acquisition.

As of December 31, 2018, we operated approximately 14,800 miles of overhead distribution lines and 7,300 miles of underground distribution cable, located in Wisconsin, as well as 120 electric distribution substations and approximately 188,600 line transformers.

Natural Gas Facilities

At December 31, 2018, our natural gas properties were located in northeastern Wisconsin and consisted of the following:

- Approximately 8,200 miles of natural gas distribution mains,
- Approximately 240 miles of natural gas transmission mains,
- Approximately 306,000 natural gas lateral services, and
- 90 natural gas distribution and transmission gate stations.

We also own office buildings, natural gas regulating and metering stations, and major service centers, including garage and warehouse facilities, in certain communities we serve. Where distribution lines and services and natural gas distribution mains and services occupy private property, we have in some, but not all instances, obtained consents, permits or easements for these installations from the apparent owners or those in possession of those properties, generally without an examination of ownership records or title.

ITEM 3. LEGAL PROCEEDINGS

In addition to those legal proceedings discussed in Note 19, Commitments and Contingencies, and Note 21, Regulatory Environment, we are currently, and from time to time, subject to claims and suits arising in the ordinary course of business. Although the results of these additional legal proceedings cannot be predicted with certainty, management believes, after consultation with legal counsel, that the ultimate resolution of these proceedings will not have a material effect on our financial statements.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

There is no established public trading market for our common stock, as Integrys, a wholly-owned subsidiary of WEC Energy Group, owns all of our outstanding common stock. See Note 10, Common Equity, for more information.

ITEM 6. SELECTED FINANCIAL DATA

Omitted pursuant to General Instruction I(2)a**.**

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

CORPORATE DEVELOPMENTS

Introduction

We are an electric and natural gas utility and an indirect wholly owned subsidiary of WEC Energy Group. We derive revenues primarily from the distribution and sale of electricity and natural gas to retail customers. We also provide wholesale electric service to numerous utilities and cooperatives for resale. We conduct our business primarily through our utility reportable segment. See Note 18, Segment Information, for more information on our reportable business segments.

Effective January 1, 2017, our customers and electric and natural gas distribution assets located in the Upper Peninsula of Michigan were transferred to UMERC, a new stand-alone utility owned by WEC Energy Group. See Note 3, Related Parties, for more information.

Effective January 1, 2017, we transferred our 10.37% ownership interest in WPSI, which held an approximate 34% interest in ATC, to another subsidiary of Integrys. See Note 3, Related Parties, for more information.

Corporate Strategy

Our goal is to continue to build and sustain long-term value for customers and shareholders by focusing on the fundamentals of our business: reliability; operating efficiency; financial discipline; customer care; and safety.

Reshaping Our Generation Fleet

WEC Energy Group has developed and is executing a plan to reshape its generation portfolio. This plan 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, WEC Energy Group set a new long-term goal of reducing CO_2 emissions by approximately 80% below 2005 levels by 2050. WEC Energy Group expects to retire a total of approximately 1,800 MW of coal-fired generation by 2020 across its electric utilities, and add additional natural gas-fired generating units and renewable generation, including utility-scale solar projects. As part of this effort, the jointly owned Edgewater 4 generating unit was retired in September 2018 (our share of 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 information related to these plant retirements.

As part of our commitment to invest in zero-carbon generation, WEC Energy Group plans to invest in utility scale solar of up to 350 MW within its Wisconsin segment, which includes us. We have 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 PSCW approval, we 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. As the cost of renewable energy generation installations continues to decline, solar projects have become cost effective opportunities for us 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.

We continue work on our SMRP, which involves modernizing parts of our electric distribution system, including burying or upgrading lines. The project focuses on constructing facilities to improve the reliability of electric service we provide to our customers. We also continue to upgrade our 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 us and our customers. This program reduces the manual effort for disconnects and reconnects and enhances outage management capabilities.

WEC Energy Group continues to focus on integrating and improving business processes and consolidating its IT infrastructure across all of its 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 earning our authorized ROE and maintaining a strong balance sheet, stable cash flows, 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, and equipment, that are no longer performing as intended, or have an unacceptable risk profile. See Note 3, Related Parties, for more information about WEC Energy Group's acquisition of Bluewater and Note 2, Acquisitions, for information on our acquisition of a portion of a wind energy generation facility in Wisconsin.

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, where our employees 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:

(in millions)	Year Ended December 31 2018	2017	2016
Operating revenues	**$ 1,498.5**	$ 1,485.4	$ 1,448.2
Cost of sales	**602.0**	573.9	527.6
Other operation and maintenance	**448.0**	447.6	503.7
Depreciation and amortization	**141.9**	139.3	124.1
Property and revenue taxes	**40.2**	39.5	39.8
Operating income	**266.4**	285.1	253.0
Other income, net	**37.6**	23.7	41.3
Interest expense	**53.9**	54.2	48.1
Income before income taxes	**250.1**	254.6	246.2
Income tax expense	**77.3**	99.7	90.5
Net income	**$ 172.8**	$ 154.9	$ 155.7

The table below shows the year-over-year income statement impacts associated with the Tax Legislation signed into law in December 2017. As shown in the table below, the changes related to the Tax Legislation had no impact on net income. See Note 14, Income Taxes, and Note 21, Regulatory Environment, for more information.

(in millions)	2018 Compared with 2017 B (W)	Change Related to Tax Legislation	Remaining Change B (W)
Operating revenues	$ 13.1	$ (30.0)	$ 43.1
Cost of sales	(28.1)	—	(28.1)
Other operation and maintenance	(0.4)	—	(0.4)
Depreciation and amortization	(2.6)	5.4	(8.0)
Property and revenue taxes	(0.7)	—	(0.7)
Operating income	(18.7)	(24.6)	5.9
Other income, net	13.9	—	13.9
Interest expense	0.3	—	0.3
Income before income taxes	(4.5)	(24.6)	20.1
Income tax expense	22.4	24.6	(2.2)
Net income	$ 17.9	$ —	$ 17.9

See below for additional information on the year-over year changes in our consolidated earnings.

Non-GAAP Financial Measures

The discussion below addresses the operating income contribution of our utility segment and includes 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 utility segment 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 utility segment operating performance. Our utility segment operating income for the years ended December 31, 2018, 2017, and 2016 was $267.1 million, $286.7 million, and $253.9 million, respectively. The operating income discussion below includes a table that provides the calculation of electric margins and natural gas margins, along with a reconciliation to utility segment operating income.

Utility Segment Contribution to Operating Income

Effective January 1, 2017, we transferred our electric customers located in the Upper Peninsula of Michigan to UMERC. See Note 3, Related Parties, for more information.

	Year Ended December 31		
(in millions)	**2018**	**2017**	**2016**
Electric revenues	**$ 1,192.1**	$ 1,201.9	$ 1,187.7
Fuel and purchased power costs	**415.0**	413.1	388.5
Total electric margins	**777.1**	788.8	799.2
Natural gas revenues	**306.4**	283.5	260.5
Cost of natural gas sold	**187.0**	160.8	139.1
Total natural gas margins	**119.4**	122.7	121.4
Total electric and natural gas margins	**896.5**	911.5	920.6
Other operation and maintenance	**447.5**	446.1	503.0
Depreciation and amortization	**141.9**	139.3	124.0
Property and revenue taxes	**40.0**	39.4	39.7
Operating income	**$ 267.1**	$ 286.7	$ 253.9

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	**$ 245.1**	$ 265.0	$ 319.5
Transmission [1]	**148.8**	148.7	149.4
Regulatory amortizations and other pass through expenses [2]	**32.4**	32.4	34.1
Earnings sharing mechanism [3]	**21.2**	—	—
Total other operation and maintenance	**$ 447.5**	$ 446.1	$ 503.0

[1] The PSCW has approved escrow accounting for our ATC and MISO network transmission expenses. As a result, we defer as a regulatory asset or liability the difference between actual transmission costs and those included in rates until recovery or refund is authorized in a future rate proceeding. During 2018, 2017, and 2016, $145.2 million, $140.9 million, and $150.7 million, respectively, of costs were billed to us by transmission providers.

[2] Regulatory amortizations and other pass through expenses are substantially offset in margins and therefore do not have a significant impact on operating income.

[3] See Note 21, Regulatory Environment, for more information about our earnings sharing mechanism.

The following tables provide information on delivered volumes by customer class and weather statistics:

	Year Ended December 31		
	MWh *(in thousands)*		
Electric Sales Volumes	**2018**	**2017**	**2016**
Customer class			
Residential	**2,935.7**	2,761.4	2,862.3
Small commercial and industrial	**4,081.2**	3,984.0	4,052.0
Large commercial and industrial	**4,020.4**	4,003.1	4,201.1
Other	**27.4**	27.7	28.7
Total retail	**11,064.7**	10,776.2	11,144.1
Wholesale	**2,587.8**	2,764.9	2,570.4
Resale	**1,087.4**	855.8	479.5
Total sales in MWh	**14,739.9**	14,396.9	14,194.0

	Year Ended December 31		
	Therms *(in millions)*		
Natural Gas Sales Volumes	**2018**	**2017**	**2016**
Customer class			
Residential	**255.4**	234.5	225.7
Commercial and industrial	**202.4**	177.6	169.5
Total retail	**457.8**	412.1	395.2
Transport	**438.7**	425.8	417.6
Total sales in therms	**896.5**	837.9	812.8

	Year Ended December 31		
	Degree Days		
Weather *	**2018**	**2017**	**2016**
Heating (7,324 normal)	**7,554**	6,942	6,715
Cooling (507 normal)	**678**	450	572

* Normal degree days are based on a 20-year moving average of monthly temperatures from the Green Bay, Wisconsin weather station.

2018 Compared with 2017

Electric Utility Margins

Electric utility margins decreased $11.7 million during 2018, compared with 2017. The significant factors impacting the lower electric utility margins were:

- A $17.9 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 21, Regulatory Environment, for more information.

- A $15.0 million decrease in wholesale margins driven both by lower sales volumes and reduced capacity rates due in part to the Tax Legislation.

These decreases in electric utility margins were partially offset by a $22.6 million increase related to higher retail sales volumes during 2018, primarily driven by favorable weather and higher use per residential and large commercial and industrial 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 8.8% colder than 2017. As measured by cooling degree days, 2018 was 50.7% warmer than 2017.

Natural Gas Utility Margins

Natural gas utility margins decreased $3.3 million during 2018, compared with 2017. The most significant factor impacting the lower natural gas utility margins was $6.7 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 21, Regulatory Environment, for more information. This decrease in natural gas utility margins was partially offset by a $3.7 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 utility segment decreased $19.6 million during 2018, compared with 2017. The decrease was driven by the $15.0 million decrease in margins discussed above and $4.6 million of higher operating expenses (which include other operation and maintenance, depreciation and amortization, and property and revenues taxes).

The significant factors impacting the increase in operating expenses during 2018, compared with 2017, were:

- A $21.2 million increase in expense related to our earnings sharing mechanism. See Note 21, Regulatory Environment, for more information.

- An $8.5 million increase in benefit costs.

These increases in operating expenses were partially offset by:

- A $13.4 million decrease in expenses across all of our plants, in part due to the retirement of Edgewater Unit 4 in September 2018 and the retirement of 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.

- An $8.1 million decrease in electric and natural gas distribution expenses, primarily driven by lower expenses incurred related to storm damage during 2018.

2017 Compared with 2016

Electric Utility Margins

Electric utility margins decreased $10.4 million during 2017, compared with 2016. The significant factors impacting the lower electric utility margins were:

- A $15.6 million decrease related to lower retail sales volumes during 2017, primarily driven by the transfer of customers and their related sales to UMERC, the impact of cooler summer weather, and an additional day of sales during 2016 due to leap year. As measured by cooling degree days, 2017 was 21.3% cooler than 2016.

- A $4.3 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, our electric margins 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.

Partially offsetting these decreases in electric utility margins was a $10.4 million increase in wholesale margins during 2017, driven by UMERC purchasing a portion of its energy from us.

Natural Gas Utility Margins

Natural gas utility margins increased $1.3 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 colder winter weather in 2017.

Operating Income

Operating income at the utility segment increased $32.8 million during 2017, compared with 2016. The increase was driven by $41.9 million of lower operating expenses (which include other operation and maintenance, depreciation and amortization, and property and revenues taxes), partially offset by the $9.1 million net decrease in margins discussed above.

The utility segment experienced lower overall operating expenses related to synergy savings resulting from the acquisition of our parent company, Integrys, by WEC Energy Group. The significant factors impacting the decrease in operating expenses during 2017, compared with 2016, which were due in part to synergy savings, were:

- A $20.0 million decrease in expenses related to an information technology project completed in 2016 to improve the billing, call center, and credit collection functions of the Integrys subsidiaries, including us. 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 us in 2017. The portion of these lower expenses related to the transfer was offset through higher depreciation and amortization, discussed below.
- A $13.5 million decrease in operation and maintenance expenses related to our plants.
- A $9.3 million decrease in benefit costs.
- An $8.8 million decrease in electric and natural gas distribution expenses, driven by lower metering costs, the transfer of customers and their related sales to UMERC, and other cost savings.

These decreases in operating expenses were partially offset by a $15.3 million increase in depreciation and amortization, driven by 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 us during 2017.

Other Segment Contribution to Operating Loss

	Year Ended December 31		
(in millions)	**2018**	**2017**	**2016**
Operating loss	**$ (0.7)**	$ (1.6)	$ (0.9)

Consolidated Other Income, Net

	Year Ended December 31		
(in millions)	**2018**	**2017**	**2016**
AFUDC – Equity	**$ 4.6**	$ 4.1	$ 19.5
Non-service components of net periodic benefit costs	**16.7**	11.8	10.5
Earnings from equity method investments	**0.8**	1.1	9.5
Other, net	**15.5**	6.7	1.8
Other income, net	**$ 37.6**	$ 23.7	$ 41.3

2018 Compared with 2017

Other income, net increased by $13.9 million during 2018, compared with 2017. The increase was driven by the 2018 deferral of costs related to the acquisition and ownership of the Forward Wind Energy Center and higher net credits from the non-service components of our net periodic pension and OPEB costs. See Note 17, Employee Benefits, for more information on our benefit costs.

2017 Compared with 2016

Other income, net decreased by $17.6 million during 2017, compared with 2016. The decrease was primarily due to lower AFUDC driven by the ReACT™ emission control technology project at Weston Unit 3 going into service during the fourth quarter of 2016. Also contributing to the decrease were lower earnings from our equity method investments due to the transfer of our ownership interest in WPSI to another subsidiary of Integrys effective January 1, 2017. See Note 3, Related Parties, for more information.

Consolidated Interest Expense

(in millions)	Year Ended December 31 2018	2017	2016
Interest expense	**$ 53.9**	$ 54.2	$ 48.1

2017 Compared with 2016

Interest expense increased by $6.1 million during 2017, compared with 2016, primarily due to a decrease in AFUDC – Debt driven by the ReACT™ emission control technology at Weston Unit 3 placed in service during the fourth quarter of of 2016.

Consolidated Income Tax Expense

	Year Ended December 31 2018	2017	2016
Effective tax rate	**30.9%**	39.2%	36.8%

2018 Compared with 2017

Our effective tax rate was 30.9% in 2018 compared to 39.2% in 2017. This decrease in our effective tax rate was primarily due to the impact of the Tax Legislation. See Note 14, Income Taxes, and Note 21, Regulatory Environment, for more information.

We expect our 2019 annual effective tax rate to be between 24% and 25%.

2017 Compared with 2016

Our effective tax rate was 39.2% in 2017 compared to 36.8% in 2016. This increase in our effective tax rate was primarily due to a decrease in tax benefits associated with AFUDC – Equity.

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	**$ 434.5**	$ 476.6	$ 389.0	$ (42.1)	$ 87.6
Investing activities	**(552.3)**	(342.4)	(340.8)	(209.9)	(1.6)
Financing activities	**118.8**	(129.4)	(51.2)	248.2	(78.2)

Operating Activities

2018 Compared with 2017

Net cash provided by operating activities decreased $42.1 million during 2018, compared with 2017, driven by:

- A $157.8 million net decrease in cash related to cash received during 2017 for net assets transferred out of our pension plan. See Note 3, Related Parties, for more information.
- An $18.5 million decrease in cash related to an increase in cash paid for income taxes during 2018, compared with 2017. This decrease in cash was due to a federal income tax refund received in 2017, primarily associated to certain property related tax deductions.

- An $11.0 million decrease in cash resulting from higher payments during 2018, compared with 2017, for natural gas we purchased to meet the requirements of our customers during the colder winter weather.

These decreases in net cash provided by operating activities were partially offset by:

- A $66.0 million decrease in contributions and payments to our pension and OPEB plans during 2018, compared with 2017.

- A $44.6 million increase in cash from lower payments for operating and maintenance expenses. During 2018, our payments related to plant maintenance and labor costs decreased, due in part to the retirement in 2018 of 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 electric and natural gas distribution costs decreased during 2018.

- A $29.6 million increase in cash related to higher overall collections from customers, primarily due to favorable weather during 2018, compared with 2017.

2017 Compared with 2016

Net cash provided by operating activities increased $87.6 million during 2017, compared with 2016, driven by:

- A $157.8 million increase in cash related to cash received for net assets transferred out of our pension plan during 2017. See Note 3, Related Parties, for more information.

- A $52.2 million increase in cash related to higher overall collections from customers, primarily due to higher commodity prices. The average per-unit cost of natural gas sold increased 9.7% during 2017, compared with 2016.

- A $47.8 million increase in cash from lower payments for operating and maintenance expenses. During 2017, our payments related to transmission, electric and natural gas distribution costs, and operation and maintenance at our plants decreased.

These increases in net cash provided by operating activities were partially offset by:

- A $65.3 million increase in contributions and payments to our pension and OPEB plans during 2017, compared with 2016.

- A $62.7 million decrease in cash resulting from higher payments for natural gas and fuel and purchased power, primarily due to higher commodity prices during 2017, compared with 2016.

- A $58.0 million net decrease in cash related to $18.1 million of cash paid for income taxes during 2017, compared with $39.9 million of cash received during 2016. This decrease in cash was primarily the result of increased bonus depreciation deductions related to large capital projects in 2016.

Investing Activities

2018 Compared with 2017

Net cash used in investing activities increased $209.9 million during 2018, compared with 2017, driven by:

- A $108.5 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.

- A $19.9 million increase in cash paid for software assets received from WBS during 2018, compared with 2017.

2017 Compared with 2016

Net cash used in investing activities increased $1.6 million during 2017, compared with 2016, driven by a $24.7 million increase in cash paid for capital expenditures, which is discussed in more detail below. This increase was partially offset by a $24.0 million decrease in cash paid for assets received from WBS during 2017, compared with 2016.

Capital Expenditures

Capital expenditures for the years ended December 31 were as follows:

(in millions)	2018	2017	2016	Change in 2018 Over 2017	Change in 2017 Over 2016
Capital expenditures	**$ 444.3**	$ 335.8	$ 311.1	$ 108.5	$ 24.7

2018 Compared with 2017

The increase in cash paid for capital expenditures during 2018, compared with the same period in 2017, was driven by higher expenditures for an advanced metering infrastructure program and a natural gas lateral project at our Fox Energy Center.

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 during 2017, was driven by higher expenditures for the SMRP. This increase was partially offset by lower expenditures for the ReACT™ emission control technology project at Weston Unit 3, which was completed in 2016, and lower expenditures for upgrades to combustion turbine units at the Fox Energy Center, which were completed in June 2017.

Financing Activities

2018 Compared with 2017

Net cash related to financing activities increased $248.2 million during 2018, compared with 2017, driven by:

- The issuance of $400.0 million of long-term debt during 2018.
- A $55.0 million decrease in dividends paid to our parent during 2018, compared with 2017. We paid a special dividend to our parent to balance our capital structure during the first quarter of 2017, driven by cash received for assets transferred out of our pension plan in January 2017.
- A $45.0 million increase in equity contributions received from our parent during 2018, compared with 2017, related to balancing our capital structure.

These increases in net cash related to financing activities were partially offset by:

- A $125.0 million net decrease in cash due to $8.7 million of net repayments of commercial paper during 2018, compared with $116.3 million of net borrowings of commercial paper in 2017.
- A $125.0 million decrease in cash related to higher repayments of long-term debt during 2018, compared with 2017.

2017 Compared with 2016

Net cash used in financing activities increased $78.2 million during 2017, compared with 2016, driven by:

- The repayment of $125.0 million of long-term debt during 2017.

- A $76.5 million increase in dividends paid to our parent during 2017. We paid a special dividend to our parent to balance our capital structure during the first quarter of 2017, driven by cash received for assets transferred out of our pension plan in January 2017.

- A $30.0 million decrease in equity contributions received from our parent during 2017, compared with 2016, related to balancing our capital structure.

These increases in net cash used for financing activities were partially offset by:

- A $122.3 million net increase in cash due to $116.3 million of net borrowings of commercial paper during 2017, compared with $6.0 million of net repayments of commercial paper in 2016.

- A $28.6 million repayment of a loan during 2016.

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.

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, and equity contributions from our parent.

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.

We maintain a bank back-up credit facility, which provides liquidity support for our 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 on our credit facility.

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 13, Long-Term Debt, for more information about our long-term debt.

Working Capital

As of December 31, 2018, our current liabilities exceeded our current assets by $157.2 million. We do not expect this to have any impact on our liquidity since we believe we have an adequate back-up line 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 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.

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 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 credit ratings on negative outlook or downgrading our credit ratings. Any such actions by credit rating agencies may make it more difficult and costly for us to issue future debt securities and certain other types of financing and could increase borrowing costs under our credit facility.

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]	$ 2,334.0	$ 55.8	$ 510.1	$ 84.7	$ 1,683.4
Energy and transportation purchase obligations [3]	1,186.1	241.8	303.0	249.8	391.5
Purchase orders [4]	115.0	39.4	29.4	7.5	38.7
Pension and OPEB funding obligations [5]	3.2	0.7	2.5	—	—
Total contractual obligations	$ 3,638.3	$ 337.7	$ 845.0	$ 342.0	$ 2,113.6

[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.

[3] Energy and transportation purchase obligations under various contracts for the procurement of fuel, power, gas supply, and associated transportation related to utility operations.

[4] Purchase obligations related to normal business operations, information technology, and other services.

[5] Obligations for pension and OPEB plans cannot reasonably be estimated beyond 2021.

The table above does not reflect estimated future payments related to the manufactured gas plant remediation liability of $90.3 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 19, Commitments and Contingencies, for more information about environmental liabilities.

AROs in the amount of $50.8 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 for the next three years are as follows:

(in millions)	
2019	$ 505.7
2020	602.7
2021	379.8
Total	$ 1,488.2

We are continuing work on the SMRP. This project includes modernizing parts of our electric distribution system, including burying or upgrading lines. The project focuses on constructing facilities to improve the reliability of electric service that we provide to our customers. We expect to invest approximately $185 million between 2019 and 2022 on this project. We also continue to upgrade our 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.

Additionally, as part of our commitment to invest in zero-carbon generation, we plan to invest in utility scale solar. We have 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. We will own 100 MW of the output of each project for a total of 200 MW. Our share of the cost of both projects is estimated to be $260 million. Subject to 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.

Common Stock Matters

For information related to our common stock matters, see Note 10, Common Equity.

Investments in Outside Trusts

We use outside trusts to fund our pension and certain OPEB obligations. These trusts had investments of approximately $871.0 million as of December 31, 2018. These trusts hold investments that are subject to the volatility of the stock market and interest rates. We contributed $0.7 million, $66.7 million, and $1.4 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 17, 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. See Note 1(p), Guarantees, and Note 12, Short-Term Debt and Lines of Credit, for more information.

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

We account for our regulated operations in accordance with accounting guidance under the Regulated Operations Topic of the FASB ASC. Our rates are determined by various regulatory commissions. Our primary regulator is the PSCW.

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 the PSCW. Recovery of the deferred costs in future rates is subject to the review and approval by the PSCW. 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 the PSCW, 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. The PSCW 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 $485.9 million, and our regulatory liabilities were $792.9 million.

Due to the Tax Legislation signed into law in December 2017, we remeasured our deferred taxes and recorded a tax benefit of $444.7 million. We have been returning this tax benefit to ratepayers through bill credits and reductions to other regulatory assets, which we expect to continue. See Note 14, Income Taxes, and Note 21, Regulatory Environment, for more information.

We expect to request or have requested recovery of the costs related to the following projects discussed in our recent rate proceedings and orders:

- In June 2016, the PSCW approved the deferral of costs related to our 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 21, Regulatory Environment, for more information. We will be required to obtain a separate approval for collection of these deferred costs in a future rate case.

- Prior to its acquisition by WEC Energy Group, Integrys initiated an information technology project with the goal of improving the customer experience at its subsidiaries, including us. 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.

See Note 21, Regulatory Environment, for more information regarding recent and pending rate proceedings and orders.

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 rates are amounts to recover fuel, natural gas, and purchased power costs. We have recovery mechanisms in place that allow us to recover or refund all or a portion of the changes in prudently incurred fuel, natural gas, and purchased power costs from rate case-approved amounts. See Item 1. Business – D. Regulation for more information on these mechanisms.

Higher commodity costs can increase our working capital requirements, result in higher gross receipts taxes, and lead to increased energy efficiency investments by our customers to reduce utility usage and/or fuel substitution. Higher commodity costs combined

with slower economic conditions also expose us to greater risks of accounts receivable write-offs as more customers are unable to pay their bills.

Weather

Our utility 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. The fixed charge included in our natural gas rates helps to mitigate the impacts of weather. A summary of actual weather information in our service territory 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 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.

Based on our 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 $2.8 million and $2.9 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 the PSCW.

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	**$ 639.3**	7.25%
OPEB trust funds	**$ 231.7**	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.

WEC Energy Group consults with its investment advisors on an annual basis to help it 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

Our service territories are within the state of Wisconsin. As such, we are exposed to market risks in the regional Midwest economy. In addition, any economic downturn or disruption of national or international markets could adversely affect the financial condition of our customers and demand for their products, which could affect their demand for our products.

Inflation

We continue to monitor the impact of inflation, especially with respect to the costs of medical plans, fuel, transmission access, construction costs, and regulatory and environmental compliance in order to minimize its effects in future years through pricing strategies, productivity improvements, and cost reductions. We do not believe the impact of general inflation will have a material impact on our future results of operations.

For additional information concerning risk factors, including market risks, see the Cautionary Statement Regarding Forward-Looking Information at the beginning of this report and Item 1A. Risk Factors.

Competitive Markets

Electric Utility Industry

The regulated energy industry continues to experience significant changes. The FERC continues to support large RTOs, which affects the structure of the wholesale market. To this end, MISO implemented the MISO Energy Markets, including the use of LMP to value electric transmission congestion and losses. Increased competition in the retail and wholesale markets, which may result from restructuring efforts, could have a significant and adverse financial impact on us.

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, and it is uncertain when, if at all, retail choice might be implemented in Wisconsin.

Natural Gas Utility Industry

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 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. We are currently unable to predict the impact of potential future industry restructuring on our results of operations or financial position.

Environmental Matters

See Note 19, 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 issued a written order in May 2018 regarding how to refund certain tax savings from the Tax Legislation to our ratepayers. 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 21, Regulatory Environment, for more information.

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.

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 test for our utility reporting unit as of July 1, 2018, and no impairment was recorded as a result of this test. At July 1, 2018, our utility reporting unit had $36.4 million of goodwill. The fair value calculated in step one of the test was greater than carrying value. The fair value of our reporting unit was 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 our reporting unit is 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 value of our reporting unit to decrease.

Key assumptions used in the income approach included ROE, the long-term growth rate used to determine the terminal value at the end of the discrete forecast period, and the discount rate. 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 value will decrease. The discount rate is based on the weighted-average cost of capital, taking into account both the after-tax cost of debt and cost of equity. The terminal year ROE is driven by our current allowed ROE. The terminal growth rate is based primarily on a combination of our service area's historical and forecasted statistics for real gross domestic product and personal income.

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 unit to determine fair value.

The underlying assumptions and estimates used in the impairment test were made as of a point in time. Subsequent changes in these assumptions and estimates could change the result of the test.

The fair value of our reporting unit exceeded its carrying value by over 50%. Based on this result, our reporting unit is not at risk of failing step one of the goodwill impairment test.

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.

We have evaluated future plans for our older and less efficient fossil fuel generating units and have retired 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 after the unit is 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.

Pulliam Units 7 and 8 and the jointly-owned Edgewater 4 generating unit were retired during 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 17, 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 through the ratemaking process.

The following table shows how a given change in certain actuarial assumptions would impact the projected benefit obligation and the reported net periodic pension cost. 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)	$ 46.8	$ 4.9
Discount rate	0.5	(41.8)	(3.4)
Rate of return on plan assets	(0.5)	N/A	3.3
Rate of return on plan assets	0.5	N/A	(3.3)

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)	$ 10.8	$ 0.4
Discount rate	0.5	(9.6)	(0.2)
Health care cost trend rate	(0.5)	(6.2)	(1.0)
Health care cost trend rate	0.5	7.4	1.2
Rate of return on plan assets	(0.5)	N/A	1.2
Rate of return on plan assets	0.5	N/A	(1.2)

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 asset assumption 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 7.25% in 2018, 2017, and 2016. The actual rate of return on pension plan assets, net of fees, was (5.9)%, 16.31%, and 8.79%, 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 17, 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 ratemaking principles followed by the PSCW. Certain items that would otherwise be immediately recognized as revenues and expenses are deferred as regulatory assets and regulatory liabilities for future recovery or refund to customers, as authorized by the PSCW.

Future recovery of regulatory assets is not assured and is generally subject to review by the PSCW 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 $485.9 million in regulatory assets and $792.9 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 $1.5 billion included accrued utility revenues of $67.1 million as of December 31, 2018.

Income Tax Expense

We are required to estimate income taxes for each of the jurisdictions in which we operate as part of the process of preparing consolidated financial statements. This process involves estimating current income tax liabilities together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for income tax and accounting purposes. These differences result in deferred income tax assets and liabilities, which are included within our balance sheets. We also assess the likelihood that our deferred income tax assets will be recovered through future taxable income. To the extent we believe that realization is not likely, we establish a valuation allowance, which is offset by an adjustment to income tax expense in our income statements.

Uncertainty associated with the application of tax statutes and regulations and the outcomes of tax audits and appeals requires that judgments and estimates be made in the accrual process and in the calculation of effective tax rates. Only income tax benefits that meet the "more likely than not" recognition threshold may be recognized or continue to be recognized. Unrecognized tax benefits are re-evaluated quarterly and changes are recorded based on new information, including the issuance of relevant guidance by the courts or tax authorities and developments occurring in the examinations of our tax returns.

Significant management judgment is required in determining our provision for income taxes, deferred income tax assets and liabilities, the liability for unrecognized tax benefits, and any valuation allowance recorded against deferred income tax assets. The assumptions involved are supported by historical data, reasonable projections, and interpretations of applicable tax laws and regulations across multiple taxing jurisdictions. Significant changes in these assumptions could have a material impact on our financial condition and results of operations. See Note 1(m), Income Taxes, and Note 14, Income Taxes, for a discussion of accounting for income taxes.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity, and Capital Resources – Market Risks and Other Significant Risks, as well as Note 1(n), Fair Value Measurements, Note 1(o), Derivative Instruments, and Note 1(p), Guarantees, for information concerning potential market risks to which we are exposed.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

A. REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholder and the Board of Directors of Wisconsin Public Service Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets and statements of capitalization of Wisconsin Public Service Corporation and subsidiary (the "Company") as of December 31, 2018 and 2017, the related consolidated statements of income, equity, and cash flows, for each of the three years in the period ended December 31, 2018, and the related notes and the schedule listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

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 Public Company Accounting Oversight Board (United States) (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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
February 26, 2019

We have served as the Company's auditor since 2002.

B. CONSOLIDATED INCOME STATEMENTS

Year Ended December 31 *(in millions)*	2018	2017	2016
Operating revenues	**$ 1,498.5**	$ 1,485.4	$ 1,448.2
Operating expenses			
Cost of sales	**602.0**	573.9	527.6
Other operation and maintenance	**448.0**	447.6	503.7
Depreciation and amortization	**141.9**	139.3	124.1
Property and revenue taxes	**40.2**	39.5	39.8
Total operating expenses	**1,232.1**	1,200.3	1,195.2
Operating income	**266.4**	285.1	253.0
Other income, net	**37.6**	23.7	41.3
Interest expense	**53.9**	54.2	48.1
Other expense	**(16.3)**	(30.5)	(6.8)
Income before income taxes	**250.1**	254.6	246.2
Income tax expense	**77.3**	99.7	90.5
Net income	**172.8**	154.9	155.7

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

C. CONSOLIDATED BALANCE SHEETS

At December 31 *(in millions, except share and per share amounts)*	2018	2017
Assets		
Current assets		
Cash and cash equivalents	**$ 8.9**	$ 7.9
Accounts receivable and unbilled revenues, net of reserves of $4.2 and $4.0, respectively	**217.1**	205.0
Accounts receivable from related parties	**26.6**	4.4
Materials, supplies, and inventories	**103.0**	107.0
Prepaid taxes	**41.4**	52.7
Other	**9.2**	13.0
Current assets	**406.2**	390.0
Long-term assets		
Property, plant, and equipment, net of accumulated depreciation of $1,620.5 and $1,633.3, respectively	**4,150.1**	3,823.0
Regulatory assets	**485.6**	382.8
Goodwill	**36.4**	36.4
Pension and OPEB assets	**92.8**	62.0
Other	**46.6**	54.5
Long-term assets	**4,811.5**	4,358.7
Total assets	**$ 5,217.7**	$ 4,748.7
Liabilities and Equity		
Current liabilities		
Short-term debt	**$ 284.4**	$ 293.1
Current portion of long-term debt	**—**	250.0
Accounts payable	**145.4**	130.4
Accounts payable to related parties	**54.2**	30.0
Other	**79.4**	66.4
Current liabilities	**563.4**	769.9
Long-term liabilities		
Long-term debt	**1,314.7**	916.2
Deferred income taxes	**520.8**	512.7
Deferred investment tax credits	**6.4**	6.7
Regulatory liabilities	**785.7**	689.3
Environmental remediation liabilities	**90.3**	99.6
Pension and OPEB obligations	**37.3**	24.0
Payables to related parties	**2.8**	3.5
Other	**126.4**	109.5
Long-term liabilities	**2,884.4**	2,361.5
Commitments and contingencies (Note 19)		
Common shareholder's equity		
Common stock – $4 par value; 32,000,000 shares authorized; 23,896,962 shares issued and outstanding	**95.6**	95.6
Additional paid in capital	**1,115.9**	996.1
Retained earnings	**558.4**	525.6
Common shareholder's equity	**1,769.9**	1,617.3
Total liabilities and equity	**$ 5,217.7**	$ 4,748.7

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

D. CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31 *(in millions)*	2018	2017	2016
Operating activities			
Net income	**$ 172.8**	$ 154.9	$ 155.7
Reconciliation to cash provided by operating activities			
Depreciation and amortization	**141.9**	139.3	124.1
Contributions and payments related to pension and OPEB plans	**(0.7)**	(66.7)	(1.4)
Deferred income taxes and investment tax credits, net	**20.6**	77.7	143.0
Cash received for pension plan assets transferred	**—**	157.8	—
Change in –			
Collateral on deposit	**4.4**	10.2	(0.2)
Accounts receivable and unbilled revenues	**(28.5)**	(15.8)	(33.1)
Materials, supplies, and inventories	**4.3**	18.9	20.3
Prepaid taxes	**11.3**	4.6	(9.2)
Other current assets	**0.9**	0.4	0.9
Accounts payable	**77.6**	(6.3)	(24.4)
Other current liabilities	**11.9**	1.2	17.7
Other, net	**18.0**	0.4	(4.4)
Net cash provided by operating activities	**434.5**	476.6	389.0
Investing activities			
Capital expenditures	**(444.3)**	(335.8)	(311.1)
Acquisition of Forward Wind Energy Center	**(77.1)**	—	—
Payments for assets received from WBS	**(30.0)**	(10.1)	(34.1)
Other, net	**(0.9)**	3.5	4.4
Net cash used in investing activities	**(552.3)**	(342.4)	(340.8)
Financing activities			
Change in short-term debt	**(8.7)**	116.3	(6.0)
Repayment of loan	**—**	—	(28.6)
Repayment of long-term debt	**(250.0)**	(125.0)	—
Repayment of subsidiary note to parent	**—**	—	(2.9)
Issuance of long-term debt	**400.0**	—	—
Payment of dividends to parent	**(140.0)**	(195.0)	(118.5)
Equity contribution from parent	**120.0**	75.0	105.0
Other, net	**(2.5)**	(0.7)	(0.2)
Net cash provided by (used in) financing activities	**118.8**	(129.4)	(51.2)
Net change in cash and cash equivalents	**1.0**	4.8	(3.0)
Cash and cash equivalents at beginning of year	**7.9**	3.1	6.1
Cash and cash equivalents at end of year	**$ 8.9**	$ 7.9	$ 3.1

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

E. CONSOLIDATED STATEMENTS OF EQUITY

(in millions)	Common Stock	Additional Paid-In Capital	Retained Earnings	Total Common Shareholder's Equity
Balance at December 31, 2015	$ 95.6	$ 861.8	$ 528.5	$ 1,485.9
Net income	—	—	155.7	155.7
Equity contribution from parent	—	105.0	—	105.0
Payment of dividends to parent	—	—	(118.5)	(118.5)
Other	—	0.1	—	0.1
Balance at December 31, 2016	$ 95.6	$ 966.9	$ 565.7	$ 1,628.2
Net income	—	—	154.9	154.9
Equity contribution from parent	—	75.0	—	75.0
Transfer of ownership interest in WPSI and related taxes	—	(25.3)	—	(25.3)
Transfer of net assets to UMERC	—	(20.6)	—	(20.6)
Payment of dividends to parent	—	—	(195.0)	(195.0)
Other	—	0.1	—	0.1
Balance at December 31, 2017	$ 95.6	$ 996.1	$ 525.6	$ 1,617.3
Net income	**—**	**—**	**172.8**	**172.8**
Equity contribution from parent	**—**	**120.0**	**—**	**120.0**
Payment of dividends to parent	**—**	**—**	**(140.0)**	**(140.0)**
Other	**—**	**(0.2)**	**—**	**(0.2)**
Balance at December 31, 2018	**$ 95.6**	**$ 1,115.9**	**$ 558.4**	**$ 1,769.9**

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

F. CONSOLIDATED STATEMENTS OF CAPITALIZATION

At December 31 *(in millions)*			2018	2017
Common shareholder's equity (see accompanying statement)			**$ 1,769.9**	$ 1,617.3
Long-term debt	**Interest Rate**	**Year Due**		
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
Total			**1,325.0**	1,175.0
Unamortized debt issuance costs			**(9.6)**	(8.3)
Unamortized discount, net			**(0.7)**	(0.5)
Total long-term debt, including current portion			**1,314.7**	1,166.2
Current portion of long-term debt			**—**	(250.0)
Total long-term debt			**1,314.7**	916.2
Total long-term capitalization			**$ 3,084.6**	$ 2,533.5

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

G. NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Nature of Operations—We are an electric and natural gas utility company that serves customers in northeastern Wisconsin and, prior to the formation of UMERC, we also served customers in the Upper Peninsula of Michigan. We are subject to the jurisdiction of, and regulation by, the PSCW, which has general supervisory and regulatory powers over virtually all phases of the public utility industry in Wisconsin. In addition, we are subject to the jurisdiction of the FERC, which regulates our natural gas pipelines and wholesale electric rates. We are an indirect, wholly owned subsidiary of WEC Energy Group.

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 us, and the electric assets previously held by WE, located in the Upper Peninsula of Michigan.

As used in these notes, the term "financial statements" refers to the consolidated financial statements. This includes the income statements, balance sheets, statements of cash flows, statements of equity, and statements of capitalization, unless otherwise noted.

The financial statements include our accounts and the accounts of our former wholly owned subsidiary, WPS Leasing, which was dissolved in July 2016. These 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 residential and commercial and industrial customers, our performance obligation is bundled to consist of both the sale and the delivery of the electric commodity.

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 our tariffs, 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. We monitor the deferral of under-collected costs to ensure that it does not cause us to earn a greater ROE than authorized by the PSCW.

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 us 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 operations 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 obligation 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 our tariffs. 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 rates, charges, terms, and conditions of service included in our tariffs, which have been approved by the PSCW. 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.

Our tariffs include various rate mechanisms that allow us to recover or refund changes in prudently incurred costs from rate case-approved amounts. Our rates 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.

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 Operating Revenues

Alternative Revenues

Alternative revenues are created from programs authorized by regulators that allow us 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. 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.

Our only alternative revenue program relates to the wholesale electric service that we provide 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
Materials and supplies	**$ 48.9**	$ 40.8
Fossil fuel	**29.2**	43.8
Natural gas in storage	**24.9**	22.4
Total	**$ 103.0**	$ 107.0

Substantially all fossil fuel, materials and supplies, and natural gas in storage 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. Depreciation as a percent of average depreciable utility plant was 2.50%, 2.55%, and 2.58% in 2018, 2017, and 2016, respectively.

We capitalize certain costs related to software developed or obtained for internal use and record these costs to amortization expense over the estimated useful life of the related software, which ranges from 3 to 15 years. If software is retired prior to being fully amortized, the difference is recorded as a loss on the income statement.

Third parties reimburse us 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.

Approximately 50% of our retail jurisdictional CWIP expenditures are subject to the AFUDC calculation. Our average AFUDC retail rates were 7.72% for 2018, 2017, and 2016. Our average AFUDC wholesale rates were 1.96%, 1.01%, and 3.00% for 2018, 2017, and 2016, respectively.

We recorded the following AFUDC for the years ended December 31:

(in millions)	2018	2017	2016
AFUDC – Debt	**$ 1.9**	$ 1.6	$ 8.1
AFUDC – Equity	**4.6**	4.1	19.5

(i) Asset Impairment—Goodwill and other intangible assets with indefinite lives are subject to an annual impairment test. Interim impairment tests are also performed when impairment indicators are present. Our utility reporting unit containing goodwill performs an annual goodwill impairment test in 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 and Other Intangible Assets, 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. 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.

(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. 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) Emission Allowances—We account for emission allowances as inventory at average cost by vintage year. Charges to income result when allowances are used in operating our generation plants. These charges are included in the costs subject to the fuel window rules. Gains on sales of allowances are returned to ratepayers.

(l) Stock-Based Compensation—Our employees participate in the WEC Energy Group stock-based compensation plans. In accordance with the WEC Energy Group shareholder approved Omnibus Stock Incentive Plan, WEC Energy Group provides long-term incentives through its equity interests to its non-employee directors, selected 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 WEC Energy Group common stock, cash, or a combination thereof. The number of shares of WEC Energy Group common stock authorized for issuance under the plan is 34.3 million.

Stock-based compensation expense is allocated to us based on the outstanding awards held by our employees and our allocation of labor costs. Awards classified as equity awards are measured based on their grant-date fair value. Awards classified as liability awards are recorded at fair value each reporting period. We account for forfeitures as they occur, rather than estimating potential future forfeitures and recording them over the vesting period.

Stock Options

Our employees are granted WEC Energy Group 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 the fair market value of WEC Energy Group common stock on the grant date. Historically, all stock options have been granted with an exercise price equal to the fair market value of WEC Energy Group common stock on the date of the grant. Options may not be exercised within 6 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 grant.

WEC Energy Group stock options are classified as equity awards. The fair value of each stock option was calculated using a binomial option-pricing model. The following table shows the estimated weighted-average fair value per stock option granted to our employees along with the weighted-average assumptions used in the valuation models:

	2018	2017	2016
Stock options granted	**21,265**	23,300	24,485
Estimated weighted-average fair value per stock option	**$ 7.68**	$ 7.53	$ 5.63
Assumptions used to value the options:			
Risk-free interest rate	**1.6% – 2.5%**	0.7% – 2.5%	0.4% – 1.8%
Dividend yield	**3.5%**	3.5%	4.0%
Expected volatility	**18.0%**	19.0%	18.0%
Expected life (years)	**5.8**	6.9	7.5

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 WEC Energy Group's dividend rate at the time of the grant and historical stock prices. Expected volatility and expected life assumptions were based on WEC Energy Group's historical experience.

Restricted Shares

WEC Energy Group restricted shares granted to our employees have a three-year vesting period with one-third of the award vesting on each anniversary of the grant date. The 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 WEC Energy Group's 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. Participants may earn between 0% and 175% of the base 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 WEC Energy Group's 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 WEC Energy Group's stock-based compensation plans.

(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. We are included in WEC Energy Group's consolidated Federal and state income tax returns. In accordance with our tax allocation agreement with WEC Energy Group, we are allocated income tax payments and refunds based upon our separate tax computation. 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.

(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 purchased power, generation, and natural gas costs for the benefit of our customers. Our approach is non-speculative and designed to mitigate risk. Our regulated hedging programs are approved by the PSCW.

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, the PSCW allows the effects of fair value accounting to be offset to regulatory assets and liabilities.

We classify derivative assets and liabilities as current or long-term on our balance sheets based on the maturities of the underlying contracts. Cash flows from derivative activities are presented in the same category as the item being hedged within operating activities on our statements of cash flows.

Derivative accounting rules provide the option to present certain asset and liability derivative positions net on the balance sheets and to net the related cash collateral against these net derivative positions. We elected not to net these items. On our balance sheets, cash collateral provided to others is reflected in other current assets. See Note 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. As of December 31, 2018, we had $20.6 million of standby letters of credit issued by financial institutions for the benefit of third parties

that extended credit to us which automatically renew each year unless proper terminations notice is given. These amounts are not reflected on our balance sheets.

(q) Employee Benefits—The costs of pension and OPEB are expensed over the periods during which employees render service. These costs are distributed among WEC Energy Group's subsidiaries based on current employment status and actuarial calculations, as applicable. Our regulators allow recovery in rates for our net periodic benefit cost calculated under GAAP. See Note 17, 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 19, 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.

We 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 PSCW'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 and natural gas service to customers in northeastern and central Wisconsin. See Note 3, Related Parties, for information regarding the transfer of our customers located in the Upper Peninsula of Michigan to UMERC as of January 1, 2017. 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. 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 Energy Generation Facility in Wisconsin

In April 2018, we, 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 our proportionate share was 44.6%, or $77.1 million. In addition, we incurred transactions costs that are recorded to a regulatory asset. Since 2008 and up until the acquisition, we 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, we are entitled to our share of generating capability and output of the facility equal to our ownership interest. We are also paying our ownership share of additional capital expenditures and operating expenses.

NOTE 3—RELATED PARTIES

We routinely enter into transactions with related parties, including WEC Energy Group, its other subsidiaries, ATC, and other affiliated entities.

We provide and receive services, property, and other items of value to and from our ultimate parent, WEC Energy Group, and other subsidiaries of WEC Energy Group.

Following WEC Energy Group's acquisition of Integrys on June 29, 2015, Integrys Business Support, LLC (IBS) changed its name to WBS, and a new AIA (Non-WBS AIA) went into effect. The Non-WBS AIA included WEC Energy Group and the former Wisconsin Energy Corporation subsidiaries. It governed the provision and receipt of services by WEC Energy Group's subsidiaries, except that WBS continued to provide services to Integrys and its subsidiaries only under the existing WBS AIAs. WBS provided services to WEC Energy Group and the former Wisconsin Energy Corporation subsidiaries under interim WBS AIAs. The Non-WBS AIA included no other significant changes from the prior Non-IBS AIA. The PSCW and all other relevant state commissions approved the Non-WBS AIA or granted appropriate waivers related to the Non-WBS AIA.

Services under the Non-WBS AIA were subject to various pricing methodologies. All services provided by any regulated subsidiary to another regulated subsidiary were priced at cost. All services provided by any regulated subsidiary to any nonregulated subsidiary were priced at the greater of cost or fair market value. All services provided by any nonregulated subsidiary to any regulated subsidiary were priced at the lesser of cost or fair market value. All services provided by any regulated or nonregulated subsidiary to WBS were priced at cost.

WBS provided several categories of services (including financial, human resource, and administrative services) to us pursuant to the WBS AIAs, which were approved, or from which we were granted appropriate waivers, by the appropriate regulators, including the PSCW. As required by FERC regulations for centralized service companies, WBS renders services at cost. The PSCW must be notified prior to making changes to the services offered under and the allocation methods specified in the WBS AIAs. Other modifications or amendments to the WBS AIAs would require PSCW approval. Recovery of allocated costs is addressed in our rate cases.

A new AIA took effect January 1, 2017. The new agreement replaced the previous agreements. The pricing methodology and services under this new agreement are substantially identical to those under the agreements that were replaced. All of the applicable state commissions approved modifications to the new AIA to incorporate WEC Energy Group's acquisition of Bluewater. See below for more information about the acquisition.

Prior to January 1, 2017, we held a 10.37% investment in WPSI which held an approximate 34% interest in ATC, a for-profit, electric transmission company regulated by the FERC and certain state regulatory commissions. Effective January 1, 2017, based upon input we received from the PSCW, we transferred our $67.2 million ownership interest in WPSI to another subsidiary of Integrys. In addition, during 2017 we transferred $41.9 million of related deferred income tax liabilities. These transactions were non-cash equity

transfers recorded to additional paid in capital between entities under common control, and therefore, did not result in the recognition of a gain or loss.

We pay ATC for 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. Services are billed to and from ATC under agreements approved by the PSCW, at each of our fully allocated costs.

We provide services to WRPC under an operating agreement approved by the PSCW. We are also under a service agreement with WRPC where we are billed for services provided by WRPC. Services are billed to and from WRPC under these agreements at a fully allocated cost.

Our balance sheets included the following receivables and payables related to transactions entered into with certain related parties:

(in millions)	December 31, 2018	December 31, 2017
Accounts receivable		
Service provided to ATC	**$ 1.2**	$ 0.7
Accounts payable		
Network transmission services from ATC	**8.8**	9.0
Liability related to income tax allocation		
Integrys	**3.5**	4.1

The following table shows activity associated with our related party transactions for the years ended December 31:

(in millions)	2018	2017	2016
Transactions with WE [1]			
Natural gas sales to WE	**1.9**	1.6	1.9
Billings to WE	**10.9**	4.5	4.2
Billings from WE	**17.8** [2]	28.2	9.0
Transactions with WBS [1]			
Billings to WBS	**17.0**	174.9 [3]	21.7 [3]
Billings from WBS [2]	**111.0**	132.9	171.0
Transactions with UMERC [4]			
Electric sales to UMERC	**15.8**	16.2	—
Natural gas sales to UMERC	**2.7**	2.5	—
Transactions with Bluewater [5]			
Storage service fees	**4.7**	0.3	—
Transactions related to ATC			
Charges to ATC for services and construction	**7.9**	6.2	8.6
Charges from ATC for network transmission services	**106.1**	107.8	109.4
Refund from ATC related to a FERC audit	**6.6**	—	—
Refund from ATC per FERC ROE order	**—**	8.9	—
Transactions with equity-method investees			
Rental payments to WRPC [6]	**1.3**	1.3	—
Purchases of energy from WRPC [6]	**—**	0.5	3.7
Charges from WRPC for services	**2.4**	2.2	—
Charges to WRPC for operations	**1.2**	0.9	0.7
Equity earnings from WPSI	**—**	—	8.7

(1) Includes amounts billed for services, pass through costs, and other items in accordance with approved AIAs.

(2) Includes $32.9 million, $10.1 million, and $34.1 million for the transfer of certain software assets from affiliates for the years ended December 31, 2018, 2017, and 2016, respectively. Includes $18.2 million for the transfer of certain benefit-related liabilities to WBS for the year ended December 31, 2016.

(3) The year ended December 31, 2017 included $157.8 million of net cash received related to our transfer of pension trust assets in conjunction with the Integrys pension plan split. Effective January 1, 2017, the Integrys Energy Group Retirement Plan was split into six separate plans. As a result, we now have our own pension plan. While the split did not impact our pension benefit obligation, federal regulations required a different allocation of assets among the new plans. Assets were transferred out of our plan in January 2017. Includes $7.3 million for the transfer of certain software assets to WBS for the year ended December 31, 2016.

(4) UMERC became operational effective January 1, 2017. See below for more information.

(5) WEC Energy Group's acquisition of Bluewater was completed June 30, 2017. See below for more information.

(6) In March 2017, we terminated our purchased power agreement with WRPC and entered into an agreement with WRPC to rent 50% of its hydroelectric power generation facilities.

Parent Company's Acquisition of Natural Gas Storage Facilities in Michigan

In June 2017, WEC Energy Group completed its acquisition of Bluewater for $226.0 million. Bluewater owns natural gas storage facilities in Michigan that provide a portion of the current storage needs for our natural gas utility operations. In September 2017, we entered into a long-term service agreement with a wholly owned subsidiary of Bluewater to take a portion of the storage, which was then approved by the PSCW in November 2017.

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. UMERC, a subsidiary of WEC Energy Group, became operational effective January 1, 2017, and we transferred customers and property, plant, and equipment as of that date. We transferred approximately 9,000 retail electric customers and 5,300 natural gas customers to UMERC, along with approximately 600 miles of electric distribution lines and approximately 100 miles of natural gas distribution mains. We also transferred related electric distribution substations in the Upper Peninsula of Michigan and all property rights for the distribution assets to UMERC. The book value of the net assets (including the related deferred income tax liabilities) transferred to UMERC from us as of January 1, 2017, was $20.6 million. This transaction was a non-cash equity transfer recorded to additional paid in capital between entities under common control, and therefore, did not result in the recognition of a gain or loss. UMERC currently meets its market obligations through power purchase agreements with us and WE.

NOTE 4—OPERATING REVENUES

Disaggregation of Operating Revenues

The following tables present our operating revenues disaggregated by revenue source. We only have revenues associated with our utility segment. We do not have any revenues associated with our other segment. 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 utility segment, 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.

	Wisconsin Public Service Corporation Consolidated
(in millions)	**Year ended December 31, 2018**
Electric utility	**$ 1,192.2**
Natural gas utility	**305.5**
Total revenues from contracts with customers	**1,497.7**
Other operating revenues	**0.8**
Total operating revenues	**$ 1,498.5**

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	$ 381.5
Small commercial and industrial	371.4
Large commercial and industrial	238.8
Other	8.5
Total retail revenues	1,000.2
Wholesale	142.3
Resale	38.5
Other utility revenues	11.2
Total electric utility operating revenues	$ 1,192.2

Natural Gas Utility Operating Revenues

The following table disaggregates natural gas utility operating revenues into customer class:

(in millions)	Natural Gas Utility Operating Revenues Year ended December 31, 2018
Residential	$ 177.7
Commercial and industrial	107.6
Total retail revenues	285.3
Transport	19.7
Other utility revenues	0.5
Total natural gas utility operating revenues	$ 305.5

Other Operating Revenues

Other operating revenues consist primarily of the following:

(in millions)	Year ended December 31, 2018
Late payment charges	$ 2.9
Leases	0.2
Alternative revenues *	(2.3)
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 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]	**$ 189.8**	$ 161.3	17
Environmental remediation costs [4]	**108.3**	116.0	19
Plant retirements	**78.1**	8.3	6
Income tax related items [5]	**38.1**	8.2	14
Termination of a tolling agreement with Fox Energy Company LLC [6]	**21.7**	27.2	
AROs	**11.5**	9.7	8
De Pere Energy Center [7]	**10.1**	14.0	
Crane Creek wind project production tax credits [8]	**0.4**	22.8	
Other, net	**27.9**	15.3	
Total regulatory assets	**$ 485.9**	$ 382.8	
Balance Sheet Presentation			
Current assets	**$ 0.3**	$ —	
Regulatory assets	**485.6**	382.8	
Total regulatory assets	**$ 485.9**	$ 382.8	

(1) Based on prior and current rate treatment, we believe it is probable that we 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 $14.7 million and $14.4 million at December 31, 2018 and 2017, respectively.

(2) As of December 31, 2018, we had $31.9 million of regulatory assets not earning a return and $5.3 million of regulatory assets earning a return based on short-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 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 $18.0 million related to these environmental remediation costs. The remaining $90.3 million represents our estimated future cash expenditures.

(5) For information on the regulatory treatment of the impacts of the Tax Legislation, see Note 21, Regulatory Environment.

(6) Represents an early termination fee of a tolling agreement we had with the Fox Energy Center. Prior to the purchase of the Fox Energy Center in 2013, we supplied natural gas for the facility and purchased capacity and the associated energy output under the tolling agreement. We are authorized recovery of this asset over a nine-year period that began on January 1, 2014.

(7) Prior to purchasing the De Pere Energy Center in 2002, we had a long-term power purchase contract with them that was accounted for as a capital lease. As a result of the purchase, the capital lease obligation was reversed, and the difference between the capital lease asset and the purchase price was recorded as a regulatory asset. We are authorized recovery of this regulatory asset through 2023.

(8) In 2012, we elected to claim and subsequently received a Section 1603 Grant for the Crane Creek wind project in lieu of the production tax credit. As a result, we reversed previously recorded production tax credits and recorded regulatory assets. In May 2018, the PSCW issued an order requiring us to use a portion of our tax benefits from the Tax Legislation that was signed into law in December 2017 to reduce the regulatory assets related to our Crane Creek wind project production tax credits. See Note 21, Regulatory Environment, for more information.

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]	**$ 418.8**	$ 393.8	14
Removal costs [2]	**241.8**	238.9	
Pension and OPEB costs [3]	**72.6**	30.2	17
Earnings sharing mechanism	**21.2**	—	21
Energy costs refundable through rate adjustments [4]	**14.3**	8.2	
Electric transmission costs	**9.7**	6.0	21
Other, net	**14.5**	20.1	
Total regulatory liabilities	**$ 792.9**	$ 697.2	
Balance Sheet Presentation			
Current liabilities	**$ 7.2**	$ 7.9	
Regulatory liabilities	**785.7**	689.3	
Total regulatory liabilities	**$ 792.9**	$ 697.2	

[1] For information on the regulatory treatment of the impacts of the Tax Legislation, see Note 21, 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 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.

NOTE 6—PROPERTY, PLANT, AND EQUIPMENT

Property, plant, and equipment consisted of the following utility and non-utility assets at December 31:

(in millions)	2018	2017
Electric – generation	**$ 2,831.2**	$ 2,624.9
Electric – distribution	**1,510.0**	1,361.9
Natural gas – distribution, storage, and transmission	**910.6**	846.4
Property, plant, and equipment to be retired	**—**	57.9
Other	**351.9**	287.6
Less: Accumulated depreciation	**1,620.1**	1,479.1
Net	**3,983.6**	3,699.6
CWIP	**166.0**	121.4
Net utility property, plant, and equipment	**4,149.6**	3,821.0
Non-utility property, plant, and equipment	**0.9**	2.3
Less: Accumulated depreciation	**0.4**	0.4
Net	**0.5**	1.9
CWIP	**—**	0.1
Net non-utility property, plant, and equipment	**0.5**	2.0
Total property, plant, and equipment	**$ 4,150.1**	$ 3,823.0

Utility Segment Plant to be Retired

We have evaluated future plans for our older and less efficient fossil fuel generating units and have retired our plants identified below. In December 2017, a severance liability in the amount of $3.6 million was recorded in other current liabilities related to these plant retirements.

(in millions)	
Severance liability at December 31, 2017	$ 3.6
Severance payments	**(0.8)**
Total severance liability at December 31, 2018	**$ 2.8**

Pulliam Power Plant

In connection with a MISO ruling, we 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 at December 31, 2018, 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. We continue 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. We have 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. We will address the accounting and regulatory treatment related to the retirement of the Pulliam power plant with the PSCW in conjunction with our anticipated 2019 rate case. See Note 19, 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 our 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. We continue 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. We have 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. We will address the accounting and regulatory treatment related to the retirement of the Edgewater 4 generating unit with the PSCW in conjunction with our anticipated 2019 rate case. See Note 19, Commitments and Contingencies, for more information.

NOTE 7—JOINTLY OWNED UTILITY FACILITIES

We hold a joint ownership interest in certain electric generating facilities. We are entitled to our share of generating capability and output of each facility equal to our respective ownership interest. We also pay our ownership share of additional construction costs, fuel inventory purchases, and operating expenses, unless specific agreements have been executed to limit our maximum exposure to additional costs. We record our proportionate share of significant jointly owned electric generating facilities as property, plant, and equipment on the balance sheets.

Information related to jointly owned utility facilities at December 31, 2018 was as follows:

(in millions, except for percentages and MW)	Weston Unit 4	Columbia Energy Center Units 1 and 2 [2]	Forward Wind Energy Center
Ownership	**70.0%**	**28.1%**	**44.6%**
Our share of rated capacity (MW) [1]	**384.9**	**314.8**	**8.7**
In-service date	**2008**	**1975 and 1978**	**2008**
Property, plant, and equipment	**$ 615.4**	**$ 438.8**	**$ 123.7**
Accumulated depreciation	**$ (205.2)**	**$ (132.2)**	**$ (43.7)**
CWIP	**$ 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 us. In October 2016, WPL received an order from the PSCW approving amendments to the Columbia joint operating agreement between the parties allowing MGE and us 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, our ownership interest would decrease to 27.5%.

Our proportionate share of direct expenses for the joint operation of these plants is recorded in operating expenses in the income statements. We have supplied our own financing for all jointly owned projects.

NOTE 8—ASSET RETIREMENT OBLIGATIONS

We have recorded AROs primarily for asbestos abatement at certain generation facilities, office buildings, and service centers; the dismantling of wind generation projects; the disposal of polychlorinated biphenyls-contaminated transformers; and the closure of fly-ash landfills at certain generation facilities. We establish regulatory assets and liabilities 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. 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	**$ 34.1**	$ 32.6	$ 32.7
Accretion	**1.8**	1.6	1.5
Additions and revisions to estimated cash flows	**16.6** [1]	0.4	(1.6) [2]
Liabilities settled	**(1.7)**	(0.5)	—
Balance as of December 31	**$ 50.8**	$ 34.1	$ 32.6

(1) AROs increased $10.7 million in 2018 due to revisions made to estimated cash flows for the abatement of asbestos at our Pulliam power plant. A $5.6 million ARO was also recorded during 2018 for the legal requirement to dismantle, at retirement, the wind generation project known as Forward Wind Energy Center. See Note 2, Acquisitions, for more information on Forward Wind Energy Center.

(2) During 2016, we revised the AROs recorded for our fly-ash landfills due to changes in estimated removal costs.

NOTE 9—GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill represents the excess of the cost of an acquisition over the fair value of the identifiable net assets acquired. We had no changes to the carrying amount of goodwill during the years ended December 31, 2018 and 2017. In the third quarter of 2018, we completed our annual goodwill impairment test, and no impairment resulted from this test.

The identifiable intangible assets other than goodwill listed below are classified as other long-term assets on our balance sheets.

	December 31, 2018			December 31, 2017		
(in millions)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized intangible assets *	**$ 8.3**	**$ (6.8)**	**$ 1.5**	$ 8.3	$ (5.6)	$ 2.7
Unamortized intangible assets	**0.4**	**—**	**0.4**	0.4	—	0.4
Total intangible assets	**$ 8.7**	**$ (6.8)**	**$ 1.9**	$ 8.7	$ (5.6)	$ 3.1

* Represents contractual service agreements that provide for major maintenance and protection against unforeseen maintenance costs related to the combustion turbine generators at the Fox Energy Center. The remaining amortization period at December 31, 2018, was approximately one year.

NOTE 10—COMMON EQUITY

Stock-Based Compensation

The following table summarizes our pre-tax stock-based compensation expense and the related tax benefit recognized in income for the years ended December 31:

(in millions)	2018	2017	2016
Stock options	**$ 0.9**	$ 0.6	$ 0.5
Restricted stock	**1.7**	0.7	1.4
Performance units	**3.6**	3.3	1.5
Stock-based compensation expense	**$ 6.2**	$ 4.6	$ 3.4
Related tax benefit	**$ 1.7**	$ 1.8	$ 1.4

Stock-based compensation costs capitalized during 2018, 2017, and 2016 were not significant.

Stock Options

The following is a summary of our employees' WEC Energy Group 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	47,785	$ 56.80		
Granted	**21,265**	**$ 66.02**		
Transferred	**1,965**	**$ 62.01**		
Outstanding as of December 31, 2018	**71,015**	**$ 59.70**	**8.0**	**$ 0.7**
Exercisable as of December 31, 2018	**7,410**	**$ 58.26**	**7.7**	**$ 0.1**

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 WEC Energy Group's closing stock price on December 31, 2018, and the option exercise price, multiplied by the number of in-the-money stock options.

As of December 31, 2018, we expected to recognize approximately $0.6 million of unrecognized compensation cost related to unvested and outstanding WEC Energy Group stock options over the next 1.6 years on a weighted-average basis.

During the first quarter of 2019, the Compensation Committee awarded 21,638 non-qualified WEC Energy Group stock options with an 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 is a summary of our employees' WEC Energy Group restricted stock activity during 2018:

Restricted Shares	Number of Shares	Weighted-Average Grant Date Fair Value
Outstanding and unvested as of January 1, 2018	11,202	$ 56.01
Granted	**1,953**	**$ 64.99**
Released	**(5,394)**	**$ 55.86**
Transferred	**457**	**$ 57.88**
Forfeited	**(793)**	**$ 57.38**
Outstanding and unvested as of December 31, 2018	**7,425**	**$ 58.45**

The intrinsic value of WEC Energy Group restricted stock held by our employees that was released was $0.3 million for each of the years ended December 31, 2018 and 2017. The actual tax benefit from released restricted shares for the same years was $0.1 million in each year. No shares of WEC Energy Group restricted stock held by our employees were released during 2016.

As of December 31, 2018, we expected to recognize approximately $0.6 million of unrecognized compensation cost related to unvested and outstanding WEC Energy Group restricted stock over the next 1.5 years on a weighted-average basis.

During the first quarter of 2019, the Compensation Committee awarded 1,889 WEC Energy Group restricted shares to our 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 8,500; 10,025; and 9,235 WEC Energy Group performance units, respectively, to our officers and other key employees under the WEC Energy Group Performance Unit Plan.

At December 31, 2018, our employees held 26,454 of outstanding WEC Energy Group performance units, including dividend equivalents. A liability of $1.7 million was recorded on our balance sheet at December 31, 2018 related to these outstanding units. As of December 31, 2018, we expected to recognize approximately $3.4 million of unrecognized compensation cost related to unvested and outstanding WEC Energy Group performance units over the next 1.3 years on a weighted-average basis.

During the first quarter of 2019, performance units held by our employees with an intrinsic value of $0.8 million were settled. The actual tax benefit from the distribution of these awards was $0.2 million. In January 2019, the Compensation Committee awarded 8,178 WEC Energy Group performance units to our officers and other key employees under its normal schedule of awarding long-term incentive compensation.

Restrictions

Various financing arrangements and regulatory requirements impose certain restrictions on our ability to transfer funds to the sole holder of our common stock, Integrys, in the form of cash dividends, loans, or advances. In addition, Wisconsin law prohibits us from making loans to or guaranteeing obligations of WEC Energy Group, Integrys, or their subsidiaries.

In accordance with our most recent rate order, we may not pay common dividends above the test year forecasted amount reflected in our rate case, if it would cause our average common equity ratio, on a financial basis, to fall below our authorized level of 51%. A return of capital in excess of the test year amount can be paid by us at the end of the year provided that our average common equity ratio does not fall below the authorized level.

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, our restricted retained earnings totaled approximately $531 million.

We do not believe that these restrictions will materially affect our operations or limit any dividend payments in the foreseeable future.

NOTE 11—PREFERRED STOCK

We have 1,000,000 shares of preferred stock with a $100 par value authorized for issuance, of which none were issued and outstanding at December 31, 2018 and 2017.

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	**$ 284.4**	$ 293.1
Average interest rate on amounts outstanding at December 31	**2.85%**	1.72%

Our average amount of commercial paper borrowings based on daily outstanding balances during 2018 was $285.5 million, with a weighted-average interest rate during the period of 2.25%.

We have entered into a bank back-up credit facility to maintain short-term credit liquidity which, among other terms, requires us to maintain, subject to certain exclusions, a total funded debt to capitalization ratio of 65% or less. As of December 31, 2018, we were in compliance with this ratio.

The information in the table below relates to our revolving credit facility used to support our commercial paper borrowing program, including remaining available capacity under this facility as of December 31:

(in millions)	Maturity	2018
Revolving credit facility	October 2022	**$ 400.0**
Less:		
Letters of credit issued inside credit facility		**1.3**
Commercial paper outstanding		**284.4**
Available capacity under existing agreement		**$ 114.3**

This facility has a renewal provision for two one-year extensions, subject to lender approval.

Our bank back-up credit facility contains customary covenants, including certain limitations on our ability to sell assets. The credit facility also contains 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.

NOTE 13—LONG-TERM DEBT

See our statements of capitalization for details on our long-term debt.

In November 2018, we issued $400.0 million of 3.35% Senior Notes due November 21, 2021. We used the net proceeds to pay all $250.0 million outstanding principal amount of our 1.65% Senior Notes at maturity in December 2018, to repay short-term debt, and for working capital and other corporate purposes.

The following table shows the future maturities of our long-term debt outstanding as of December 31, 2018:

(in millions)	Payments
2019	$ —
2020	—
2021	400.0
2022	—
2023	—
Thereafter	925.0
Total	$ 1,325.0

We amortize debt premiums, discounts, and debt issuance costs over the life of the debt and we include the costs in interest expense.

NOTE 14—INCOME TAXES

Income Tax Expense

The following table is a summary of income tax expense for each of the years ended December 31:

(in millions)	2018	2017	2016
Current tax expense (benefit)	**$ 56.7**	$ 22.0	$ (52.5)
Deferred income taxes, net	**20.9**	78.0	143.3
Investment tax credit, net	**(0.3)**	(0.3)	(0.3)
Total income tax expense	**$ 77.3**	$ 99.7	$ 90.5

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		2016	
(in millions)	Amount	Effective Tax Rate	Amount	Effective Tax Rate	Amount	Effective Tax Rate
Expected tax at statutory federal tax rates	**$ 52.5**	**21.0 %**	$ 89.1	35.0 %	$ 86.2	35.0 %
State income taxes net of federal tax benefit	**15.4**	**6.2 %**	12.7	5.0 %	11.6	4.7 %
Federal excess amortization *	**11.6**	**4.6 %**	—	— %	—	— %
AFUDC – Equity	**(1.0)**	**(0.4)%**	(1.4)	(0.5)%	(6.8)	(2.7)%
Other, net	**(1.2)**	**(0.5)%**	(0.7)	(0.3)%	(0.5)	(0.2)%
Total income tax expense	**$ 77.3**	**30.9 %**	$ 99.7	39.2 %	$ 90.5	36.8 %

* See Note 21, Regulatory Environment, for more information about the impact of the Tax Legislation.

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 $444.7 million. Accordingly, this amount was recorded as both an increase to regulatory liabilities as well as a decrease to certain existing regulatory assets as of December 31, 2017.

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, analyzed the impact on Alternative Minimum Tax Credit carryforwards, 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 are as follows:

(in millions)	2018	2017
Deferred tax assets		
Tax gross up – regulatory items	**$ 105.5**	$ 99.3
Other	**23.9**	7.9
Total deferred tax assets	**$ 129.4**	$ 107.2
Deferred tax liabilities		
Property-related	**588.1**	563.5
Employee benefits and compensation	**40.9**	37.7
Other	**21.2**	18.7
Total deferred tax liabilities	**650.2**	619.9
Deferred tax liability, net	**$ 520.8**	$ 512.7

Consistent with rate-making treatment, deferred taxes in the table above are offset for temporary differences that have related regulatory assets and liabilities.

At December 31, 2018, we had $1.3 million of tax credit carryforwards resulting in deferred tax assets of $1.3 million. Federal tax credit carryforwards begin to expire in 2038. We expect to have future taxable income sufficient to utilize these deferred tax assets. At December 31, 2017, we had $1.4 million and $6.3 million of federal charitable contribution and tax credit carryforwards resulting in deferred tax assets of $0.3 million and $6.3 million, respectively. At December 31, 2018, we had $1.1 million of state net operating losses resulting in deferred tax assets of $0.4 million. These state net operating loss carryforwards begin to expire in 2029. We expect to have future taxable income sufficient to utilize these deferred tax assets. At December 31, 2017, we had $6.7 million and $1.4 million of state net operating loss and charitable contribution carryforwards resulting in deferred tax assets of $0.4 million and $0.1 million, respectively.

Unrecognized Tax Benefits

We had no unrecognized tax benefits at December 31, 2018 and 2017.

We do not expect any unrecognized tax benefits to affect our effective tax rate in periods after December 31, 2018.

For the years ended December 31, 2018, 2017, and 2016, we recognized no interest and no penalties related to unrecognized tax benefits in our income statements. For the years ended December 31, 2018 and 2017, we had no interest accrued and no penalties accrued related to unrecognized tax benefits on our balance sheets.

We do not anticipate any significant increases in the total amounts of unrecognized tax benefits within the next 12 months.

Our primary tax jurisdictions include Federal and the state of Wisconsin. With a few exceptions, we are no longer subject to Federal income tax examinations by the IRS for years prior to 2015. As of December 31, 2018, we were subject to examination by the Wisconsin taxing authority for tax years 2014 through 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	**$ 0.8**	**$ —**	**$ —**	**$ 0.8**
FTRs	**—**	**—**	**3.0**	**3.0**
Coal contracts	**—**	**0.4**	**—**	**0.4**
Total derivative assets	**$ 0.8**	**$ 0.4**	**$ 3.0**	**$ 4.2**
Derivative liabilities				
Natural gas contracts	**$ 1.1**	**$ —**	**$ —**	**$ 1.1**

	December 31, 2017			
(in millions)	Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	$ 0.8	$ —	$ —	$ 0.8
Petroleum products contracts	0.3	—	—	0.3
FTRs	—	—	2.0	2.0
Coal contracts	—	0.4	—	0.4
Total derivative assets	$ 1.1	$ 0.4	$ 2.0	$ 3.5
Derivative liabilities				
Natural gas contracts	$ 2.3	$ —	$ —	$ 2.3
Coal contracts	—	0.5	—	0.5
Total derivative liabilities	$ 2.3	$ 0.5	$ —	$ 2.8

The derivative assets and liabilities listed in the tables above include options, futures, physical commodity contracts, and other instruments used to manage market risks related to changes in commodity prices. They also include FTRs, which are used to manage electric transmission congestion costs in the MISO Energy Markets.

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	**$ 2.0**	$ 2.0	$ 2.0
Realized and unrealized losses	**—**	—	(0.2)
Purchases	**9.0**	6.9	7.1
Sales	**—**	—	(0.2)
Settlements	**(8.0)**	(6.9)	(6.7)
Balance at the end of the period	**$ 3.0**	$ 2.0	$ 2.0

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 our income statements.

Fair Value of Financial Instruments

The following table shows the financial instruments included on our balance sheets that are not recorded at fair value:

	December 31, 2018		December 31, 2017	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	**$ 1,314.7**	**$ 1,372.9**	$ 1,166.2	$ 1,302.4

The fair value of long-term debt is categorized within Level 2 of the fair value hierarchy.

NOTE 16—DERIVATIVE INSTRUMENTS

The following table shows our derivative assets and derivative liabilities, none of which are designated as hedging instruments.

	December 31, 2018		December 31, 2017	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Other current				
Natural gas contracts	**$ 0.8**	**$ 1.0**	$ 0.8	$ 1.9
Petroleum products contracts	**—**	**—**	0.3	—
FTRs	**3.0**	**—**	2.0	—
Coal contracts	**0.2**	**—**	—	0.5
Total other current	**$ 4.0**	**$ 1.0**	$ 3.1	$ 2.4
Other long-term				
Natural gas contracts	**$ —**	**$ 0.1**	$ —	$ 0.4
Coal contracts	**0.2**	**—**	0.4	—
Total other long-term	**$ 0.2**	**$ 0.1**	$ 0.4	$ 0.4
Total	**$ 4.2**	**$ 1.1**	$ 3.5	$ 2.8

Realized gains (losses) on derivatives are primarily recorded in cost of sales on the income statements. Our estimated notional sales volumes and realized gains (losses) were as follows:

	December 31, 2018		December 31, 2017		December 31, 2016	
(in millions)	Volume	Gains	Volume	Gains (Losses)	Volume	Gains (Losses)
Natural gas contracts	38.4 Dth	**$ 5.1**	18.6 Dth	$ (2.4)	28.6 Dth	$ (1.4)
Petroleum products contracts	1.8 gallons	**0.4**	1.3 gallons	0.1	4.4 gallons	(0.6)
FTRs	9.3 MWh	**12.5**	9.1 MWh	6.4	8.4 MWh	6.0
Total		**$ 18.0**		$ 4.1		$ 4.0

At December 31, 2018 and 2017, we had posted cash collateral of $0.5 million and $4.9 million, respectively, in our margin accounts.

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	**$ 4.2**	**$ 1.1**	$ 3.5	$ 2.8
Gross amount not offset on the balance sheet	**(0.8)**	**(1.1)** [1]	(1.1)	(2.3) [2]
Net amount	**$ 3.4**	**$ —**	$ 2.4	$ 0.5

[1] Includes cash collateral posted of $0.3 million.

[2] Includes cash collateral posted of $1.2 million.

NOTE 17—EMPLOYEE BENEFITS

Pension and Other Postretirement Employee Benefits

Through December 31, 2016, we participated in the Integrys Energy Group Retirement Plan, a noncontributory, qualified pension plan sponsored by WBS. We were responsible for our share of the plan assets and obligations. Effective January 1, 2017, the Integrys Energy Group Retirement Plan was split into six separate plans. As a result, we now have our own pension plan. While the split did not impact our pension benefit obligation, federal regulations required a different allocation of assets among the new plans. Assets were transferred out of our plan in January 2017; however, we made additional contributions to the plan as discussed below.

We serve as plan sponsor and administrator for certain OPEB plans. The benefits are funded through irrevocable trusts, as allowed for income tax purposes. Our balance sheets reflect only the liabilities associated with our past and current employees and our share of the plan assets and obligations. WEC Energy Group also offers medical, dental, and life insurance benefits to our active employees and their dependents. We expense the allocated costs of these benefits as incurred.

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 the 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 the pension and OPEB plans qualify as a regulatory asset.

The following tables provide a reconciliation of the changes in our share of the 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	**$ 704.7**	$ 655.2	**$ 220.2**	$ 223.1
Service cost	**10.4**	9.0	**6.1**	6.2
Interest cost	**26.0**	26.7	**8.2**	9.1
Plan amendments	**—**	—	**(1.5)**	(21.7)
Net transfer to/from affiliates	**—**	—	**(0.1)**	—
Actuarial (gain) loss	**(42.7)**	45.1	**(70.7)**	12.2
Participant contributions	**—**	—	**1.2**	1.0
Benefit payments	**(34.3)**	(31.3)	**(9.9)**	(9.7)
Transfer	**—**	—	**(2.1)**	$ —
Obligation at December 31	**$ 664.1**	$ 704.7	**$ 151.4**	$ 220.2
Change in fair value of plan assets				
Fair value at January 1	**$ 712.4**	$ 736.6	**$ 250.5**	$ 231.1
Actual return on plan assets	**(39.4)**	99.2	**(10.3)**	27.1
Employer contributions	**0.6**	65.7	**0.1**	1.0
Participant contributions	**—**	—	**1.2**	1.0
Benefit payments	**(34.3)**	(31.3)	**(9.9)**	(9.7)
Net transfer to/from affiliates	**—**	(157.8) *	**0.1**	—
Fair value at December 31	**$ 639.3**	$ 712.4	**$ 231.7**	$ 250.5
Funded status at December 31	**$ (24.8)**	$ 7.7	**$ 80.3**	$ 30.3

* Related to our transfer of pension trust assets in conjunction with the Integrys pension plan split for the year ended December 31, 2017. Assets were transferred out of our plan in January 2017. See Note 3, Related Parties, for more information.

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**
Pension and OPEB assets	**$ —**	$ 15.6	**$ 92.8**	$ 46.4
Pension and OPEB obligations	**24.8**	7.9	**12.5**	16.1
Total net (liabilities) assets	**$ (24.8)**	$ 7.7	**$ 80.3**	$ 30.3

The accumulated benefit obligation for the defined benefit pension plans was $594.1 million and $652.0 million at December 31, 2018 and 2017, respectively.

The following table shows information for pension plans with an accumulated benefit obligation in excess of plan assets. There were no plan assets related to these pension plans. Amounts presented are as of December 31:

(in millions)	2018	2017
Projected benefit obligation	**$ 7.3**	$ 7.9
Accumulated benefit obligation	**7.3**	7.9

The following table shows the amounts that had not yet been recognized in our net periodic benefit cost as of December 31:

	Pension Costs		OPEB Costs	
(in millions)	2018	2017	2018	2017
Net regulatory assets (liabilities)				
Net actuarial loss (gain)	**$ 220.4**	$ 196.5	**$ (17.9)**	$ 27.2
Prior service credits	**—**	—	**(82.8)**	(92.6)
Total	**$ 220.4**	$ 196.5	**$ (100.7)**	$ (65.4)

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	$ 17.8	$ 1.6
Prior service credits	—	(11.4)
Total 2019 – estimated amortization	$ 17.8	$ (9.8)

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	**$ 10.4**	$ 9.0	$ 9.9	**$ 6.1**	$ 6.2	$ 7.3
Interest cost	**26.0**	26.7	27.0	**8.2**	9.1	10.6
Expected return on plan assets	**(48.3)**	(46.4)	(52.6)	**(17.8)**	(16.7)	(15.9)
Loss on plan settlement	**—**	—	3.4	**—**	—	—
Amortization of prior service credit	**—**	—	—	**(11.3)**	(9.8)	(7.4)
Amortization of net actuarial loss	**21.1**	17.3	18.0	**2.5**	2.5	2.5
Net periodic benefit cost (credit)	**$ 9.2**	$ 6.6	$ 5.7	**$ (12.3)**	$ (8.7)	$ (2.9)

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	$ 435.8	$ 11.8	$ 447.6	$ 493.2	$ 10.5	$ 503.7
Other expense						
Other income, net	11.9	11.8	23.7	30.8	10.5	41.3

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%**	3.70%	**4.29%**	3.67%
Rate of compensation increase	**4.00%**	4.00%	**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	**5.90%**	6.00%
Ultimate trend rate (Post 65)	**N/A**	N/A	**5.00%**	5.00%
Year ultimate trend rate is reached (Post 65)	**N/A**	N/A	**2028**	2028

The weighted-average assumptions used to determine net periodic benefit cost for the plans were as follows for the years ended December 31:

	Pension Costs		
	2018	**2017**	**2016**
Discount rate	**3.70%**	4.19%	4.25%
Expected return on assets	**7.25%**	7.25%	7.25%
Rate of compensation increase	**4.00%**	4.00%	4.00%

	OPEB Costs		
	2018	**2017**	**2016**
Discount rate	**3.67%**	4.11%	4.46%
Expected return on 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)	**6.00%**	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

WEC Energy Group consults with its investment advisors on an annual basis to help 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 asset assumption for the pension plan and OPEB plans is 7.25%.

Assumed health care cost trend rates have a significant effect on the amounts reported by us for the 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	$ 2.5	$ (1.9)
Effect on the health care component of the accumulated postretirement benefit obligation	15.2	(12.1)

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.

Our pension trust target asset allocation is 45% equity investments, 45% fixed income investments, and 10% private equity and real estate investments. The OPEB trust has a target asset allocation of 45% equity investments and 55% fixed income investments. Equity securities include investments in large-cap, mid-cap, and small-cap companies. Fixed income securities include corporate bonds of companies from diversified industries, mortgage and other asset backed securities, commercial paper, and United States Treasuries.

Pension and OPEB plan investments are recorded at fair value. See Note 1(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	$ 79.0	$ —	$ —	$ 79.0	$ 24.0	$ —	$ —	$ 24.0
International Equity	80.1	0.3	—	80.4	27.0	0.2	—	27.2
Fixed income securities: *								
United States Bonds	16.3	119.1	—	135.4	46.9	37.0	—	83.9
International Bonds	2.3	21.0	—	23.3	2.5	1.6	—	4.1
	$ 177.7	$ 140.4	$ —	$ 318.1	$ 100.4	$ 38.8	$ —	$ 139.2
Investments measured at net asset value				$ 321.2				$ 92.5
Total	$ 177.7	$ 140.4	$ —	$ 639.3	$ 100.4	$ 38.8	$ —	$ 231.7

* This category represents investment grade bonds of United States and foreign issuers denominated in United States dollars from diverse industries.

	December 31, 2017							
	Pension Plan Assets				OPEB Assets			
(in millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Asset Class								
Cash and cash equivalents	$ —	$ 22.2	$ —	$ 22.2	$ 9.2	$ 0.3	$ —	$ 9.5
Equity securities:								
United States Equity	97.9	—	—	97.9	26.5	—	—	26.5
International Equity	98.2	—	0.4	98.6	31.8	—	0.2	32.0
Fixed income securities: *								
United States Bonds	17.8	129.2	—	147.0	47.0	35.7	—	82.7
International Bonds	2.3	21.2	—	23.5	2.5	1.8	—	4.3
Private Equity and Real Estate	—	62.9	12.5	75.4	—	0.7	0.1	0.8
	$ 216.2	$ 235.5	$ 12.9	$ 464.6	$ 117.0	$ 38.5	$ 0.3	$ 155.8
Investments measured at net asset value				$ 247.8				$ 94.7
Total	$ 216.2	$ 235.5	$ 12.9	$ 712.4	$ 117.0	$ 38.5	$ 0.3	$ 250.5

* 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:

	Private Equity and Real Estate		International Equity	
(in millions)	**Pension**	**OPEB**	**Pension**	**OPEB**
Beginning balance at January 1, 2018	**$ 12.5**	**$ 0.1**	**$ 0.4**	**$ 0.2**
Realized and unrealized losses	**0.7**	**—**	**(0.1)**	**—**
Purchases	**2.4**	**—**	**—**	**—**
Transfers out of level 3	**(15.6)**	**(0.1)**	**(0.3)**	**(0.2)**
Ending balance at December 31, 2018	**$ —**	**$ —**	**$ —**	**$ —**

	Private Equity and Real Estate		International Equity		U.S. Bonds
(in millions)	**Pension**	**OPEB**	**Pension**	**OPEB**	**Pension**
Beginning balance at January 1, 2017	$ —	$ —	$ —	$ —	$ 0.5
Realized and unrealized losses	—	—	(0.1)	—	(0.5)
Purchases	12.5	0.1	0.5	0.2	—
Ending balance at December 31, 2017	$ 12.5	$ 0.1	$ 0.4	$ 0.2	$ —

Cash Flows

We expect to contribute $0.7 million to the pension plans in 2019, dependent upon various factors affecting us, including our liquidity position and the effects of the new Tax Legislation. We expect to contribute an insignificant amount to the OPEB plans in 2019.

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	$ 34.7	$ 7.8
2020	35.5	8.9
2021	36.5	9.2
2022	37.0	8.7
2023	36.3	8.9
2024-2028	185.7	46.9

Savings Plans

WEC Energy Group sponsors a 401(k) savings plan that allows substantially all of our full-time 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, which amounts are contributed to an employee's savings plan account based on the employee's wages, age, and years of service. Our share of the total costs incurred under all of these plans was $9.9 million in 2018, $9.6 million in 2017, and $9.0 million in 2016.

NOTE 18—SEGMENT INFORMATION

We use operating income to measure segment profitability and to allocate resources to our businesses. At December 31, 2018, we reported two segments, which are described below.

Our utility segment includes our electric and natural gas utility operations, which serve customers in northeastern and central Wisconsin. Our electric utility operations are engaged in the generation, distribution, and sale of electricity. Our natural gas utility operations are engaged in the purchase, distribution, and sale of natural gas to retail customers as well as the transportation of

customer-owned natural gas. Effective January 1, 2017, we transferred our customers and electric and natural gas distribution assets located in the Upper Peninsula of Michigan to UMERC. See Note 3, Related Parties for more information.

During 2018 and 2017, the other segment included non-utility activities, as well as equity earnings from our investment in WRPC. During 2016, the other segment included non-utility activities as well as equity earnings from our investments in WRPC and WPSI. Effective January 1, 2017, we transferred our 10.37% ownership interest in WPSI to another subsidiary of Integrys. See Note 3, Related Parties, for more information.

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**	**Other**	**Reconciling Eliminations**	**Wisconsin Public Service Corporation Consolidated**
External revenues	**$ 1,498.5**	**$ —**	**$ —**	**$ 1,498.5**
Other operation and maintenance	**447.5**	**0.5**	**—**	**448.0**
Depreciation and amortization	**141.9**	**—**	**—**	**141.9**
Operating income (loss)	**267.1**	**(0.7)**	**—**	**266.4**
Other income, net	**35.2**	**2.4**	**—**	**37.6**
Interest expense	**53.9**	**—**	**—**	**53.9**
Capital expenditures and asset acquisitions	**521.4**	**—**	**—**	**521.4**
Total assets	**5,151.5**	**66.2**	**—**	**5,217.7**

2017 ***(in millions)***	**Utility**	**Other**	**Reconciling Eliminations**	**Wisconsin Public Service Corporation Consolidated**
External revenues	$ 1,485.4	$ —	$ —	$ 1,485.4
Other operation and maintenance *	446.1	1.5	—	447.6
Depreciation and amortization	139.3	—	—	139.3
Operating income (loss) *	286.7	(1.6)	—	285.1
Other income, net *	21.0	2.7	—	23.7
Interest expense	54.2	—	—	54.2
Capital expenditures	335.8	—	—	335.8
Total assets	4,678.1	70.6	—	4,748.7

* Includes the retroactive restatement impacts of the implementation of ASU 2017-07. See Note 17, Employee Benefits, for more information on this new standard.

2016 ***(in millions)***	**Utility**	**Other**	**Reconciling Eliminations**	**Wisconsin Public Service Corporation Consolidated**
External revenues	$ 1,448.2	$ —	$ —	$ 1,448.2
Intersegment revenues	—	0.3	(0.3)	—
Other operation and maintenance *	503.0	1.0	(0.3)	503.7
Depreciation and amortization	124.0	0.1	—	124.1
Operating income (loss) *	253.9	(0.9)	—	253.0
Other income, net *	33.8	7.5	—	41.3
Interest expense	48.0	0.1	—	48.1
Capital expenditures	311.1	—	—	311.1
Total assets	4,686.4	121.8	—	4,808.2

* Includes the retroactive restatement impacts of the implementation of ASU 2017-07. See Note 17, Employee Benefits, for more information on this new standard.

NOTE 19—COMMITMENTS AND CONTINGENCIES

We 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

We have obligations to distribute and sell electricity and natural gas to our customers and expect to recover costs related to these obligations in future customer rates. In order to meet these obligations, we routinely enter into long-term purchase and sale commitments for various quantities and lengths of time.

The following table shows our minimum future commitments related to these purchase obligations as of December 31, 2018.

			Payments Due By Period					
(in millions)	Date Contracts Extend Through	Total Amounts Committed	2019	2020	2021	2022	2023	Later Years
Electric utility:								
Purchased power	2041	$ 410.8	$ 75.1	$ 48.2	$ 46.8	$ 41.8	$ 39.7	$ 159.2
Coal supply and transportation	2024	325.4	115.0	63.1	48.2	47.6	50.8	0.7
Natural gas utility supply and transportation	2048	449.9	51.7	50.3	46.4	43.0	26.9	231.6
Total		$ 1,186.1	$ 241.8	$ 161.6	$ 141.4	$ 132.4	$ 117.4	$ 391.5

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 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 territory were designated as partial nonattainment: Door, Manitowoc, 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. WEC Energy Group's plan, which includes us, is to work with its 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 WEC Energy Group's CO_2 reduction goals. As a result of WEC Energy Group's generation reshaping plan, we retired approximately 300 MW of coal generation in 2018, consisting of 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 5.7 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 6.4 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 operations distribute and sell. For 2017, we reported aggregated CO_2 equivalent emissions of approximately 3.5 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 3.8 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.

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. We 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, we 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.

There has 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 retirement of Pulliam Units 7 and 8, we do not believe that BTA determinations will be necessary for these units. We also have provided information to the WDNR about planned unit retirements.

As a result of past capital investments completed to address 316(b) compliance, 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 requirement that affects us relates to discharge limits for bottom ash transport water (BATW). 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. 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, 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 generating unit retirements, the only facility that will require bottom ash system modifications is Weston Unit 3. Based on preliminary engineering, the estimated rule compliance cost is approximately $20 million.

Land Quality

Manufactured Gas Plant Remediation

We have identified sites at which we 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. We 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	**$ 108.3**	$ 116.0
Reserves for future remediation	**90.3**	99.6

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 have achieved a renewable energy percentage of 9.74% and met our compliance requirements by constructing various wind parks and by also relying on renewable energy purchases. We continue to review our renewable energy portfolio and acquire cost-effective renewables as needed to meet our requirements on an ongoing basis. The PSCW administers the renewable program related to Act 141, and we fund the program, along with other utilities, based on 1.2% of our annual operating revenues.

Enforcement and Litigation Matters

We 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

Consent Decree – Weston and Pulliam Power Plants

In November 2009, the EPA issued an NOV to us, which alleged violations of the CAA's New Source Review requirements relating to certain projects completed at the Weston and Pulliam plants from 1994 to 2009. 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 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, we retired Weston Unit 1 and Pulliam Units 5 and 6. In May 2016, the EPA approved our 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. We retired Pulliam Units 7 and 8 on October 21, 2018. See Note 6, Property, Plant, and Equipment, for more information about the retirement. We completed the mitigation projects required

and received a completeness letter from the EPA in October 2018. We plan to request termination of the Consent Decree during 2019.

We received approval from the PSCW in our 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, we recorded a regulatory asset of $11.5 million for the undepreciated book value. In addition, we received approval from the PSCW in our 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 us. The NOV alleged violations of the CAA's New Source Review requirements related to certain projects completed at those plants. We, 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.

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 our portion totaling $1.3 million, and
- our 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 20—SUPPLEMENTAL CASH FLOW INFORMATION

(in millions)	2018	2017	2016
Cash (paid) for interest, net of amount capitalized	**$ (52.9)**	$ (55.5)	$ (54.6)
Cash (paid) received for income taxes, net	**(36.6)**	(18.1)	39.9
Significant non-cash transactions:			
Accounts payable related to construction costs	**8.1**	46.4	67.2
Receivable related to corporate-owned life insurance proceeds	**6.4**	—	—
Transfer of ownership in WPSI to another subsidiary of Integrys *	**—**	67.2	—
Transfer of net assets to UMERC *	**0.4**	20.6	—

* See Note 3, Related Parties, for more information on these transactions.

NOTE 21—REGULATORY ENVIRONMENT

Tax Cuts and Jobs Act of 2017

In December 2017, we deferred for return to ratepayers, through future refunds, bill credits, or reductions in other regulatory assets, the estimated tax benefit of $444.7 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.

In May 2018, the PSCW issued an order regarding the benefits associated with the Tax Legislation. The PSCW order requires our electric utility operations to use 40% of the current 2018 and 2019 tax benefits to reduce certain regulatory assets. The remaining 60% is to be returned to electric customers in the form of bill credits. For our 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 utility operations and is being deferred for our natural gas utility operations. The timing and method of returning the remaining net tax benefit associated with the revaluation of deferred taxes for our electric and natural gas utility operations was not addressed and will be determined in a future rate proceeding.

2018 and 2019 Rates

During April 2017, we, along with WE and WG, filed an application with the PSCW for approval of a settlement agreement we made with several of our 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 our electric and natural gas customers. Based on the PSCW order, our authorized ROE remains at 10.0%, and our current capital cost structure 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. Additionally, the agreement allows us 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 our 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, we also agreed to adopt, beginning in 2018, the earnings sharing mechanism that has been in place for WE and WG since January 2016, and agreed to keep the mechanism in place through 2019. Under this earnings sharing mechanism, if we earn above our 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 anticipate initiating a rate proceeding with the PSCW by April 1, 2019.

Acquisition of a Wind Energy Generation Facility in Wisconsin

In October 2017, we, 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.

Proposed Solar Generation Projects

On May 31, 2018, we, 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, we will own 100 MW of the output of each project for a total of 200 MW. Our share of the cost of both projects is estimated to be $260 million.

Natural Gas Storage Facilities in Michigan

In January 2017, WEC Energy Group signed an agreement for the acquisition of Bluewater. Bluewater owns natural gas storage facilities in Michigan that provide a portion of the current storage needs for our natural gas utility operations. As a result of this agreement, we, along with WE and WG, 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 requested that the PSCW review and confirm the reasonableness and prudency of our potential long-term storage service agreement and interstate natural gas transportation contracts related to the storage facilities. We, along with WE and WG, also requested approval to amend WEC Energy Group's AIA to ensure WBS and WEC Energy Group's other subsidiaries could provide services to the storage facilities. During June 2017, the PSCW granted, subject to various conditions, these declarations and approvals, and WEC Energy Group acquired Bluewater on June 30, 2017. In September 2017, we entered into the long-term service agreement for the natural gas storage, which was then approved by the PSCW in November 2017. See Note 3, Related Parties, for more information.

2016 Wisconsin Rate Order

In April 2015, we initiated a rate proceeding with the PSCW. In December 2015, the PSCW issued a final written order, 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, we would have realized an electric rate increase. Based on the order, the PSCW allowed us to escrow ATC and MISO network transmission expenses through 2016. In addition, system support resource payments are being escrowed until a future rate proceeding. The order directed us 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 us 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, we 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, we 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 our large commercial and industrial customers who entered into a service agreement with us under Real Time Market Pricing prior to April 15, 2016. These requests were approved by the PSCW in June 2016.

NOTE 22—OTHER INCOME, NET

Total other income, net was as follows for the years ended December 31:

(in millions)	2018	2017	2016
AFUDC – Equity	**$ 4.6**	$ 4.1	$ 19.5
Non-service components of net periodic benefit costs	**16.7**	11.8	10.5
Earnings from equity method investments	**0.8**	1.1	9.5
Other, net	**15.5**	6.7	1.8
Other income, net	**$ 37.6**	$ 23.7	$ 41.3

NOTE 23—QUARTERLY FINANCIAL INFORMATION (Unaudited)

(in millions)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2018					
Operating revenues	**$ 393.6**	**$ 350.1**	**$ 379.2**	**$ 375.6**	**$ 1,498.5**
Operating income	**69.2**	**72.4**	**86.4**	**38.4**	**266.4**
Net income	**49.8**	**42.7**	**57.0**	**23.3**	**172.8**
2017					
Operating revenues	$ 389.6	$ 341.6	$ 380.7	$ 373.5	$ 1,485.4
Operating income *	73.0	58.1	108.2	45.8	285.1
Net income	39.3	30.7	60.9	24.0	154.9

* Includes the retroactive restatement impacts of the implementation of ASU 2017-07. See Note 17, Employee Benefits, for more information on this new standard.

NOTE 24—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 and did not identify any leases that were significant, 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.
- 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. We do not expect the adoption of Topic 842 to result in us recording any significant right of use assets or related lease liabilities related to operating leases, and we had no capital leases upon adoption. 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.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Our management, with the participation of our principal executive officer and principal financial officer, has evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Based upon such evaluation, our principal executive officer and principal financial officer have concluded that, as of the end of such period, our disclosure controls and procedures are effective: (i) in recording, processing, summarizing and reporting, on a timely basis, information required to be disclosed by us in the reports that we file or submit under the Exchange Act; and (ii) to ensure that information required to be disclosed in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our 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 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.

This Annual Report on Form 10-K does not include an attestation report of our independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by our independent registered public accounting firm pursuant to rules of the SEC that permit us to provide only management's report in this annual report.

Changes in Internal Control Over Financial Reporting

During 2018, WEC Energy Group completed an enterprise resource planning (ERP) system integration project to bring all of its subsidiaries, including us, 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.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE OF THE REGISTRANT

Omitted pursuant to General Instruction I(2)c.

ITEM 11. EXECUTIVE COMPENSATION

Omitted pursuant to General Instruction I(2)c.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Omitted pursuant to General Instruction I(2)c.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Omitted pursuant to General Instruction I(2)c.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The following is a summary of the fees for professional services provided to us by Deloitte & Touche LLP in 2018 and 2017:

Fees	2018	2017
Audit fees [1]	**$ 789,324**	$ 902,154
Tax fees [2]	**—**	3,592
All other fees [3]	**1,227**	637
Total fees	**$ 790,551**	$ 906,383

[1] *Audit Fees*. Consists of aggregate fees for the audits of the annual consolidated financial statements and reviews of the interim condensed consolidated financial statements included in quarterly reports. Audit fees also include services that are normally provided by Deloitte & Touche LLP in connection with statutory and regulatory filings or engagements, including comfort letters, consents, and other services related to SEC matters, and consultations arising during the course of the audits and reviews concerning financial accounting and reporting standards.

[2] *Tax Fees*. Consists of fees for professional services rendered with respect to federal and state tax compliance and tax advice. This can include preparation of tax returns, claims for refunds, payment planning, and tax law interpretation.

[3] *All Other Fees*. Consists of fees for services provided to us by Deloitte & Touche LLP for products and services other than the services reported above. All Other Fees relate to utility training seminars and a subscription cost for the use of a Deloitte & Touche LLP accounting research tool.

No audit related fees were paid to Deloitte & Touche LLP in 2017 or 2018. No fees were paid to Deloitte & Touche LLP pursuant to the "de minimus" exception to the pre-approval policy permitted under the Exchange Act.

Policy on Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of Independent Registered Public Accounting Firm

The Audit and Oversight Committee (Audit Committee) of the Board of Directors of WEC Energy Group, which is comprised solely of independent directors, is responsible for reviewing and approving, in advance, all audit, audit-related, tax, and other services of the independent auditor. The Committee has the sole authority to select, evaluate, and where appropriate, terminate and replace the independent auditor.

The Audit Committee is committed to ensuring the independence of the auditor, both in appearance as well as in fact. In order to assure continuing auditor independence, the Audit Committee periodically considers whether there should be a regular rotation of the independent external audit firm. In addition, the Audit Committee is directly involved in the selection of the independent auditor's lead engagement partner.

Pre-Approval Process

Before engagement of the independent auditor for the next year's audit, the independent auditor will submit (i) a description of all services anticipated to be rendered during the following year, as well as an estimate of the fees for each of the services, for the Audit Committee to approve, and (ii) written confirmation that the performance of any non-audit services is permissible and will not impact the firm's independence. Annual pre-approval will be deemed effective for a period of twelve months from the date of the pre-approval, unless the Audit Committee specifically provides for a different period. A fee level will be established for all permissible, pre-approved non-audit services. Any additional audit service, audit related service, tax service and other service must also be pre-approved.

The Audit Committee delegated pre-approval authority to the Audit Committee's chair. The Audit Committee chair is required to report any pre-approval decisions at the next Audit Committee meeting. Under the pre-approval policy, the Audit Committee may not delegate to management its responsibilities to pre-approve services performed by the independent auditor.

Prohibited Activities are services prohibited by the SEC or by the Public Company Accounting Oversight Board to be performed by our independent auditor. These services include:

- bookkeeping or other services related to the accounting records or financial statements of the Company;
- financial information systems design and implementation;
- appraisal or valuation services, fairness opinions or contribution-in-kind reports;
- actuarial services;
- internal audit outsourcing services;
- management functions or human resources;
- broker-dealer, investment advisor or investment banking services;
- legal services and expert services unrelated to the audit;
- services provided for a contingent fee or commission; and
- services related to planning, marketing or opining in favor of the tax treatment of a confidential transaction or aggressive tax position transaction that was initially recommended, directly or indirectly, by the independent auditor.

In addition, the independent auditor may not provide any services, including personal financial counseling and tax services, to any officer or other employee of WEC Energy Group or its subsidiaries who serves in a financial reporting oversight role or to the chair of the Audit Committee or to an immediate family member of these individuals, including spouses, spousal equivalents, and dependents.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

1. Financial Statements and Report of Independent Registered Public Accounting Firm Included in Part II of This Report

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Consolidated Statements of Capitalization as of December 31, 2018 and 2017.	52
Notes to Consolidated Financial Statements.	53

2. Financial Statement Schedules Included in Part IV of This Report

Schedule II, Valuation and Qualifying Accounts, for the three years ended December 31, 2018, 2017, and 2016.	96

Other schedules are omitted because of the absence of conditions under which they are required or because the required information is given in the financial statements or notes thereto.

3. Exhibits and Exhibit Index

The following exhibits are filed or furnished with or incorporated by reference in the report with respect to Wisconsin Public Service Corporation (File No. 1-3016). An asterisk (*) indicates incorporation by reference pursuant to Exchange Act Rule 12b-32.

Number	Exhibit
3	**Articles of Incorporation and By-laws**
3.1*	Restated Articles of Incorporation of Wisconsin Public Service Corporation ("WPS''), as effective May 26, 1972, and amended through May 31, 1988 and Articles of Amendment to Restated Articles of Incorporation of WPS dated June 9, 1993 (Exhibit 4.1 to Registration Statement on Form S-3, Reg. No. 333-182491, filed July 2, 2012).
3.2*	By-Laws of WPS, as amended through June 29, 2015, Inclusive (Exhibit 3.2 to Form 10-K for the year ended December 31, 2015).

4 Instruments defining the rights of security holders, including indentures

4.1* Indenture, dated as of December 1, 1998, by and between WPS and U.S. Bank National Association (successor to Firstar Bank Milwaukee, N.A., National Association) (Exhibit 4A to Form 8-K filed December 18, 1998).

4.2* First Supplemental Indenture, dated as of December 1, 1998, by and between WPS and Firstar Bank Milwaukee, N.A., National Association (Exhibit 4C to Form 8-K filed December 18, 1998).

4.3* Fifth Supplemental Indenture, dated as of December 1, 2006, by and between WPS and U.S. Bank National Association (Exhibit 4.1 to Form 8-K filed November 30, 2006).

4.4* Ninth Supplemental Indenture, dated as of December 1, 2012, by and between WPS and U.S. Bank National Association (Exhibit 4.1 to Form 8-K filed November 29, 2012).

4.5* Tenth Supplemental Indenture, dated as of November 1, 2013, by and between WPS and U.S. Bank National Association (Exhibit 4.1 to Form 8-K filed November 18, 2013).

4.6* Twelfth Supplemental Indenture, dated as of November 21, 2018, by and between WPS and U.S. Bank National Association (Exhibit 4.1 to Form 8-K filed November 21, 2018).

Certain agreements and instruments with respect to unregistered debt not exceeding 10% of the total assets of the Registrant have been omitted as permitted by related instructions. We agree pursuant to Item 601(b)(4) of Regulation S-K to furnish to the Securities and Exchange Commission, upon request, a copy of all such agreement and instruments.

10 Material Contracts

10.1* # Joint Plant Agreement by and between WPS and Dairyland Power Cooperative, dated as of November 23, 2004 (Exhibit 10.19 to Integrys Energy Group's and WPS's Form 10-K for the year ended December 31, 2004).

Note: Certain compensatory plans, contracts or arrangements in which directors or executive officers of WPS participate are not filed as WPS exhibits in reliance on the exclusion in Item 601(b)(10)(iii)(C)(6) of Regulation S-K. WPS is a wholly-owned subsidiary of WEC Energy Group, Inc., Commission File No. 001-09057, and such compensatory plans, contracts or arrangements are filed as exhibits to WEC Energy Group's periodic reports under the Securities Exchange Act of 1934.

23 Consents of experts and counsel

23.1 Consent of Independent Registered Public Accounting Firm for WPS.

31 Rule 13a-14(a) / 15d-14(a) Certifications

31.1 Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32 Section 1350 Certifications

32.1 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

101 Interactive Data File

Portions of this exhibit have been redacted and are subject to a confidential treatment request filed with the Secretary of SEC pursuant to Rule 24b-2 under the Securities and Exchange Act of 1934, as amended. The redacted material was filed separately with the SEC.

Exhibit 21 has been omitted pursuant to General Instruction I(2)b.

ITEM 16. FORM 10-K SUMMARY

None.

SCHEDULE II
WISCONSIN PUBLIC SERVICE CORPORATION
VALUATION AND QUALIFYING ACCOUNTS

Allowance for Doubtful Accounts *(in millions)*	**Balance at Beginning of Period**	**Expense [1]**	**Net Write-offs [2]**	**Balance at End of Period**
December 31, 2018	**$ 4.0**	**$ 6.0**	**$ (5.8)**	**$ 4.2**
December 31, 2017	3.0	5.0	(4.0)	4.0
December 31, 2016	2.5	7.7	(7.2)	3.0

[1] Net of recoveries.

[2] Represents amounts written off to the reserve, net of adjustments to regulatory assets.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

WISCONSIN PUBLIC SERVICE CORPORATION

By /s/ J. KEVIN FLETCHER
J. Kevin Fletcher
Chairman of the Board and Chief Executive Officer

Date: February 26, 2019

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

/s/ J. KEVIN FLETCHER	February 26, 2019
J. Kevin Fletcher, Chairman of the Board and Chief Executive Officer and Director -- Principal Executive Officer	
/s/ SCOTT J. LAUBER	February 26, 2019
Scott J. Lauber, Executive Vice President, Chief Financial Officer, Treasurer and Director -- Principal Financial Officer	
/s/ WILLIAM J. GUC	February 26, 2019
William J. Guc, Vice President and Controller -- Principal Accounting Officer	
/s/ MARGARET C. KELSEY	February 26, 2019
Margaret C. Kelsey, Director	
/s/ GALE E. KLAPPA	February 26, 2019
Gale E. Klappa, Director	
/s/ TOM METCALFE	February 26, 2019
Tom Metcalfe, Director	

Supplemental Information to be Furnished with Reports Filed Pursuant to Section 15(d) of the Act by Registrants Which Have Not Registered Securities Pursuant to Section 12 of the Act:

Wisconsin Public Service Corporation is not required to send an annual report or proxy statement to its sole shareholder, Integrys Holding, Inc., a wholly-owned subsidiary of WEC Energy Group, Inc., and will not prepare such a report after the filing of this Annual Report on Form 10-K for the year ended December 31, 2018. Accordingly, Wisconsin Public Service Corporation will not file such a report with the Securities and Exchange Commission.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-222430 on Form S-3 of our report dated February 26, 2019, relating to the consolidated financial statements and financial statement schedule of Wisconsin Public Service Corporation (the "Company"), appearing in this Annual Report on Form 10-K of the Company for the year ended December 31, 2018.

/s/ DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
February 26, 2019

Exhibit 31.1

Certification Pursuant to
Rule 13a-14(a) or 15d-14(a),
as Adopted Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, J. Kevin Fletcher, certify that:

1. I have reviewed this Annual Report on Form 10-K of Wisconsin Public Service Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an Annual Report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2019

/s/ J. KEVIN FLETCHER

J. Kevin Fletcher
Chief Executive Officer and President
(Principal Executive Officer)

Exhibit 31.2

Certification Pursuant to
Rule 13a-14(a) or 15d-14(a),
as Adopted Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Scott J. Lauber, certify that:

1. I have reviewed this Annual Report on Form 10-K of Wisconsin Public Service Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an Annual Report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 26, 2019

/s/ SCOTT J. LAUBER

Scott J. Lauber
Senior Executive Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

Exhibit 32.1

Certification Pursuant to
18 U.S.C. Section 1350,
As Adopted Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of Wisconsin Public Service Corporation (the "Company") on Form 10-K for the period ended December 31, 2018, as filed with the Securities and Exchange Commission on February 26, 2019 (the "Report"), I, J. Kevin Fletcher, Chairman and Chief Executive Officer of the Company, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ J. KEVIN FLETCHER

J. Kevin Fletcher
Chief Executive Officer and President

February 26, 2019

Exhibit 32.2

Certification Pursuant to
18 U.S.C. Section 1350,
As Adopted Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of Wisconsin Public Service Corporation (the "Company") on Form 10-K for the period ended December 31, 2018, as filed with the Securities and Exchange Commission on February 26, 2019 (the "Report"), I, Scott J. Lauber, Executive Vice President, CFO and Treasurer of the Company, hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ SCOTT J. LAUBER

Scott J. Lauber
Senior Executive Vice President, Chief Financial Officer, and Treasurer
February 26, 2019

GRETCHEN WHITMER
GOVERNOR

STATE OF MICHIGAN
DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS
PUBLIC SERVICE COMMISSION

ORLENE HAWKS
DIRECTOR

NORMAN J. SAARI
COMMISSIONER

SALLY A. TALBERG
CHAIRMAN

DANIEL C. SCRIPPS
COMMISSIONER

MPSC
Code of Conduct Annual Report
For Year Ending December 31, 2018

Company Name: Wisconsin Electric Power Company

Address: 231 W. Michigan St.

City: Milwaukee **State:** WI **Zip Code:** 53233

Filing For: Electric Utility: (X) Alternative Electric Supplier: ( ) Cooperative: ( )

The Commission order dated October, 29, 2001 in Case No. U-12134 adopted the Code of Conduct, consistent with PA 141, MCL 460.10 *et seq.* Section VII C of the code requires all regulated electric utilities and alternative electric suppliers (AES) file an annual report with the MPSC summarizing the number and types of complaints receive and their resolution.

1. **Are Code of Conduct documents kept at a designated company office in the state of Michigan?**

   No (X) Yes ( ) where Milwaukee, WI

2. **Please submit the following information on any Code of Conduct complaints:**
   - **A. The name of the person or company filing the complaint.**
   - **B. The date the complaint was filed.**
   - **C. A written statement of the nature of the complaint.**
   - **D. Resolution or results of process to the complaint.**

   (Attach documents to this form)

3. **No Code of Conduct complaints filed. (X) Check here.**

4. **Name of company officer responsible for Code of Conduct.**

Print Name: Margaret Kelsey

Title: Executive Vice President, General Counsel, and Corporate Secretary

I certify that the foregoing statement and information is true and correct to the best of my knowledge.

Signature: _____ **Date:** 12 April 2019

Telephone # (414) 221-4626 **Fax #** ( ) _____

Mail, Email or E-file to:

Michigan Public Service Commission
Regulated Energy Division
Attn: Lacie Latimore
7109 W Saginaw Hwy, PO Box 30221
Lansing, Michigan 48909
email to: latimorel@michigan.gov
e-file to: U-12134

F-03

GRETCHEN WHITMER
GOVERNOR

STATE OF MICHIGAN
DEPARTMENT OF LICENSING AND REGULATORY AFFAIRS
PUBLIC SERVICE COMMISSION

ORLENE HAWKS
DIRECTOR

NORMAN J. SAARI
COMMISSIONER

SALLY A. TALBERG
CHAIRMAN

DANIEL C. SCRIPPS
COMMISSIONER

MPSC
Code of Conduct Annual Report
For Year Ending December 31, 2018

Company Name: Upper Michigan Energy Resources Corporation

Address: 231 W. Michigan St.

City: Milwaukee **State:** WI **Zip Code:** 53233

Filing For: Electric Utility: (X) Alternative Electric Supplier: ( ) Cooperative: ( )

The Commission order dated October, 29, 2001 in Case No. U-12134 adopted the Code of Conduct, consistent with PA 141, MCL 460.10 *et seq.* Section VII C of the code requires all regulated electric utilities and alternative electric suppliers (AES) file an annual report with the MPSC summarizing the number and types of complaints receive and their resolution.

1. **Are Code of Conduct documents kept at a designated company office in the state of Michigan?**

   No (X) Yes ( ) where Milwaukee, WI

2. **Please submit the following information on any Code of Conduct complaints:**
   - **A. The name of the person or company filing the complaint.**
   - **B. The date the complaint was filed.**
   - **C. A written statement of the nature of the complaint.**
   - **D. Resolution or results of process to the complaint.**

   (Attach documents to this form)

3. **No Code of Conduct complaints filed. (X) Check here.**

4. **Name of company officer responsible for Code of Conduct.**

Print Name: Margaret Kelsey

Title: Executive Vice President, General Counsel, and Corporate Secretary

I certify that the foregoing statement and information is true and correct to the best of my knowledge.

Signature: _____ **Date:** 12 April, 2019

Telephone # (414) 221-4626 **Fax #** ( ) _____

Mail, Email or E-file to:

Michigan Public Service Commission
Regulated Energy Division
Attn: Lacie Latimore
7109 W Saginaw Hwy, PO Box 30221
Lansing, Michigan 48909
email to: latimorel@michigan.gov
e-file to: U-12134

F-03

Report of Employee Transfers

Year	ID	Name	New Co	Old Co	New Company
2018	24024	Catherine E Moore	2000	WE01	WBS
2018	24459	Lisa M Conway	WE01	2000	Wisconsin Electric
2018	25602	Cynthia A Danielewski	2000	WE01	WBS
2018	25724	Brian G Dobberke	2000	WE01	WBS
2018	26251	Matthew C Emerson	2000	WE01	WBS
2018	26269	Patricia J Drzewiecki	2000	WE01	WBS
2018	26651	Johnnie Fields Jr	2000	WE01	WBS
2018	29839	Arlen A Folker	2000	WE01	WBS
2018	33699	Jeffrey O Peterson	WE01	WE07	Wisconsin Electric
2018	33839	Melissa Gleason	2000	WE01	WBS
2018	34191	Kristine M Jardin Stoneking	WE01	2000	Wisconsin Electric
2018	34485	Valerie S Degerstedt	WE07	WE01	Wisconsin Gas
2018	34858	Tiffany T Harder	WE01	2000	Wisconsin Electric
2018	35497	William A Stock	2000	WE01	WBS
2018	36331	Kim Keller	WE01	2000	Wisconsin Electric
2018	37687	Matthew R Mickelsen	2000	WE01	WBS
2018	38276	Susan S Craft	2000	WE01	WBS
2018	40029	Briana Redmond	2000	WE01	WBS
2018	40035	Ashanta T Garrett	WE01	2000	Wisconsin Electric
2018	40723	Tiara S Joyner	2000	WE01	WBS
2018	45330	Amy L Plato	WE01	WE07	Wisconsin Electric
2018	46299	Joseph K Fletcher	2000	WE01	WBS
2018	49058	Shane M Sampo	WE01	2000	Wisconsin Electric
2018	50273	Carly A Casper	WE01	2000	Wisconsin Electric
2018	50433	Daniel J Szedziewski	WE07	WE01	Wisconsin Gas
2018	53436	Karl E Vierthaler	2000	WE07	WBS

Previous Company
Wisconsin Electric
WBS
Wisconsin Electric
Wisconsin Electric
Wisconsin Electric
Wisconsin Electric
Wisconsin Electric
Wisconsin Electric
Wisconsin Gas
Wisconsin Electric
WBS
Wisconsin Electric
WBS
Wisconsin Electric
WBS
Wisconsin Electric
Wisconsin Electric
Wisconsin Electric
WBS
Wisconsin Electric
Wisconsin Gas
Wisconsin Electric
WBS
WBS
Wisconsin Electric
Wisconsin Gas

Financial Statements of Non-regulated Subsidiaries

WEC Energy Group, Inc. owns several non-regulated consolidating subsidiaries. A description and high level financial information is provided for these entities. Copies of financial statements for these entities will be made available upon request at the corporate headquarters.

Information below is for the year ended December 31, 2018. All numbers below are in thousands (000's).

WEC Energy Group, Inc.: This is the parent holding company.

Net Income (Loss)*	$(36,855)
Total Assets**	$3,100,114

ATC Holding, LLC:
Formed for the purpose of holding the member interests in the American Transmission Company LLC previously held by Edison Sault Electric Company. Is a wholly owned subsidiary of WEC Energy Group, Inc.

Net Income (Loss)	$82,753
Total Assets	$1,259,024

SSS Holdings, LLC: Formed to acquire and hold title to transportation and other business-related assets for common use by WEC and its affiliates. Is a whole owned subsidiary of WEC Energy Group, Inc.

Net Income (Loss) ^^	$(1,633)
Total Assets	$3,837

WEC Business Services, LLC: Purpose is to provide business support services to WEC Energy Group, Inc. and its subsidiaries. Is a wholly owned subsidiary of WEC Energy Group, Inc.

Net Income (Loss)	$(2,243)
Total Assets	$506,734

WE Power, LLC and subsidiaries: Formed for the purpose of designing, constructing, owning, and leasing new power plants in the State of Wisconsin. Is a wholly owned subsidiary of WEC Energy Group, Inc.

Net Income (Loss)	$227,338
Total Assets	$2,701,201

Wisconsin Energy Capital Corporation: Engages in investing and financing activities. Is a wholly owned subsidiary of WEC Energy Group, Inc.

Net Income (Loss)	$955

Total Assets $111,308

WEC Infrastructure, LLC and subsidiaries: A holding company directly owned by WEC Energy Group, Inc. to invest in utility related assets.

Net Income (Loss) $2,495
Total Assets $264,619

Wisconsin Energy Services, LLC: Formed to facilitate WEC's potential investment in the purchase and operation of energy assets that may be sold by the State of Wisconsin. Is a wholly owned subsidiary of WEC Energy Group, Inc.

Net Income (Loss) ^^ $0
Total Assets $100

Wispark, LLC and subsidiaries: A full service real estate development company with a reputation of completing high-quality and complex development projects. Wispark develops real estate projects that support and complement key programs of WEC and the development efforts of communities with WEC's utility service territories. Is a wholly owned subsidiary of WEC Energy Group, Inc.

Net Income (Loss) $(1,964)
Total Assets $61,939

Wisvest, LLC: Invests in energy-related entities and is a wholly owned subsidiary of WEC Energy Group, Inc.

Net Income (Loss) ^^ $12
Total Assets $0

WEC Investments, LLC: Formed for the purpose of holding the interests of WEC Energy Group in investment funds it may decide to invest in, particularly those funds related to the energy industry. Is a wholly owned subsidiary of WEC Energy Group, Inc.

Net Income (Loss) ^^ $274
Total Assets $6,271

Integrys Holding, Inc.: Formed as an intermediate holding company that, through its subsidiaries, engages principally in natural gas utility operations and other diversified energy businesses. Is a wholly owned subsidiary of WEC Energy Group, Inc.

Net Income (Loss)* $(19,249)
Total Assets** $793,760

Peoples Energy, LLC: Formed as an intermediate holding company that, through its subsidiaries, engages principally in natural gas utility operations. Is a wholly owned subsidiary of Integrys Holding, Inc.

Net Income (Loss)*^ $571
Total Assets** $58

Peoples Energy Ventures, LLC: Formed to pursue investments in diversified energy-related businesses. Is a wholly owned subsidiary of Peoples Energy, LLC.

Net Income (Loss) $0
Total Assets $804

Peoples Gas Neighborhood Development Corporation: Invests in housing rehabilitation projects in the City of Chicago in partnership with Chicago Equity Fund, Inc. Is a wholly owned subsidiary of The Peoples Gas Light and Coke Company.

Net Income (Loss) $12
Total Assets $93

WPS Power Development, LLC: Formed to develop or acquire and operate nonregulated power generation facilities. Is a wholly owned subsidiary of Integrys Holding, Inc.

Net Income (Loss) ^ $(21)
Total Assets $192,656

WPS Visions, Inc.: Holds ownership in miscellaneous investments. Is a wholly owned subsidiary of Integrys Holding, Inc.

Net Income (Loss) ^ $(1)
Total Assets $97

Penvest, Inc.: Held investments in real estate. Was a wholly owned subsidiary of Integrys Holding, Inc. Penvest, Inc. was sold in January 2018.

Net Income (Loss) $0
Total Assets $0

WPS Investments, LLC: Held a membership interest in American Transmission Company. Integrys Holding, Inc. owned 90% and Wisconsin Public Service Corporation owned 10%. This was dissolved and moved to ATC Holding Co. in January 2018, which is a wholly owned subsidiary of WEC Energy Group, Inc.

Net Income (Loss) $0
Total Assets $0

* - Excludes equity earnings from subsidiaries
** - Excludes investments in subsidiaries
^ - These companies are LLC’s; their taxes are reflected at Integrys Holding Inc.
^^ - These companies are LLC’s; their taxes are reflected at WEC Energy Group, Inc.

Organization Chart
Regulated Entities and Affiliates

As of March 31, 2019						
Level	1	2	3	4	5	
1	**WEC Energy Group, Inc.**					
2		ATC Holding LLC (100%)				
3			ATC Development Manager, Inc. (74.73%) **			
3			ATC HoldCo LLC (75.1690%) **			
3			ATC Management Inc. (60.32%)			
3			American Transmission Company LLC (60.31%)			
2		Bluewater Natural Gas Holding, LLC				
3			Bluewater Gas Storage, LLC			
3			BGS Kimball Gas Storage, LLC			
2		Integrys Holding, Inc.				
3			**Michigan Gas Utilities Corporation**			
3			**Minnesota Energy Resources Corporation**			
3			Peoples Energy, LLC			
4				**North Shore Gas Company**		
4				Peoples Energy Ventures, LLC		
5					Peoples Energy Neighborhood Development, LLC	
5					Peoples Technology, LLC	
4				**The Peoples Gas Light and Coke Company**		
5					Peoples Gas Neighborhood Development Corporation	
3			**Wisconsin Public Service Corporation**			
4				Wisconsin River Power Company (50%)		
4				Wisconsin Valley Improvement Company (27%)		
3			WPS Power Development, LLC			
4				Integrys MA Solar, LLC		
4				Integrys Residential Solar, LLC		
4				PERC Holdings, LLC		
4				Sunbury Holdings, LLC		
4				Sunny Templeton, LLC		
3			WPS Visions, Inc.			
2		SSS Holdings, LLC				
2		**Upper Michigan Energy Resources Corporation**				
2		W.E. Power, LLC				
3			Elm Road Generating Station Supercritical, LLC			
3			Elm Road Services, LLC			
3			Port Washington Generating Station, LLC			
2		**WEC Business Services LLC**				
2		WEC Infrastructure LLC				
3			Bishop Hill Energy III Holdings LLC (90%)			
4				Bishop Hill Energy III LLC (100%)		
3			Coyote Ridge Wind, LLC (80%)			
3			Upstream Wind Energy Holdings LLC (80%)			
4				Upstream Wind Energy LLC (100%)		
2		WEC Investments, LLC				
2		**Wisconsin Electric Power Company**				
2		Wisconsin Energy Capital Corporation				
2		Wisconsin Energy Services, LLC				
3			State Energy Services, LLC (50%)			
2		**Wisconsin Gas LLC**				
2		Wispark LLC				
3			2825 FMRC LLC			
3			2825 Four Mile Road LLC			
3			CenterPoint Wispark Land Company LLC (32.95%)			
3			LakeView XV Venture LLC (1.19%)			
3			LakeView XVII Venture LLC (1.19%)			
3			LakeView XVIII Venture LLC (1.19%)			
3			Oak Creek Lakeside Land Holding LLC			
3			One West Drexel LLC			
2		Wisvest LLC				
1	We Energies Foundation, Inc.					
1	Wisconsin Public Service Foundation, Inc.					
1	WPS Community Foundation, Inc.					

Report of Creditor Recourse

There are no arrangements that allow an affiliate to obtain credit in a manner that permits a creditor, upon default, to have recourse to or in any way encumber the utility's assets.

Report of Internal Audit

To be in compliance with MPSC Case No. U-12134, audit reports from our internal audit department who have conducted audits of intercompany transactions between the utility affiliates and non-utility affiliates are filed annually by July 1. The audit report for 2018 intercompany transactions will be filed by July 1, 2019.

Summary of Intercompany Transactions

Intercompany transactions occurring between the utility and non-utility affiliates follow an Affiliated Interest Agreement. The Affiliated Interest Agreement stipulates the determination and payments of costs and charges between companies for services provided. The agreement states that all services provided by the utility to the non-utility affiliates shall be charged at the greater of cost or market value and all services provided by the non-utility affiliates to the utility shall be charged at the lesser of cost or market value. The costs and charges for services provided between utilities shall be at cost. A report of the intercompany transactions information for Michigan Gas Utilities Corporation can be found in the MPSC filing on form P-522. The information for Wisconsin Public Service Corporation can be found in the MPSC filing on form P-521 and P-522. The information for Wisconsin Electric Power Company can be found in the MPSC filing on form P-521.

WEC Energy Group

NOTICE OF 2019 ANNUAL MEETING AND PROXY STATEMENT

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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.

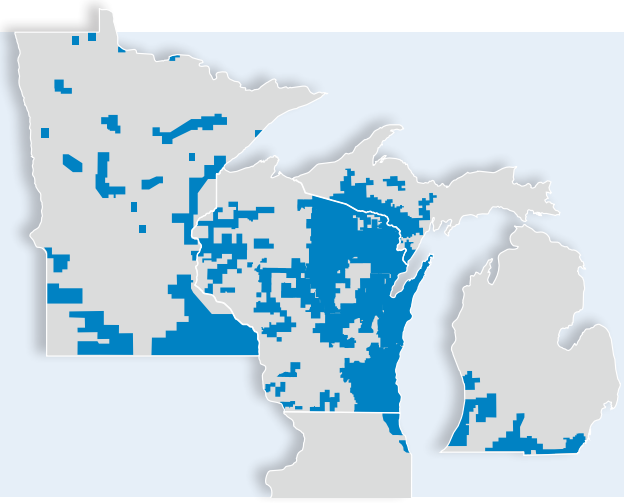
70,100 miles
of electric distribution

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.

In 2018, PA Consulting Group named We Energies best in the Midwest for the eighth year in a row for keeping the lights on for our customers.

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.

Dear Fellow Stockholders,

On behalf of our Board of Directors, I want to thank you for your investment in WEC Energy Group. As we prepare for our 2019 Annual Meeting of Stockholders, I ask for your support of the three proposals presented in this proxy statement. As you review each of these matters, please consider the following highlights from 2018, all of which demonstrate our commitment to applying strong corporate governance principles, while actively engaging in oversight of the Company's strategy, financial and operational performance, risk management, and executive leadership.

Strategy

Throughout 2018, the Board engaged in substantive discussions with management about WEC Energy Group's long-term strategy. Strategies must be evaluated in appropriate context, and in our case, we actively considered the many risks and opportunities facing the utility sector, including new technologies, customer preferences, commodity prices, energy resiliency efforts, climate change, cyber-security, and evolving shareholder engagement on environmental, social and governance initiatives.

Examples of strategic areas on which the Board provided critical oversight and input in 2018 include:

- WEC Energy Group's long-term goal to reduce carbon dioxide emissions by approximately 80 percent below 2005 levels by 2050;
- Reshaping the Company's generation fleet by balancing the need for energy resilience and fuel diversity with customer preferences and environmental objectives;
- Investment in renewable energy projects that will add carbon-free resources to our generating fleet, and others that bolster our energy infrastructure segment;
- Capital spending for projects centered on upgrading reliability, customer service, and information technology systems; and
- Regulatory and legislative priorities at the state and federal levels, from tax reform to climate change.

Management Succession Planning

In October 2017, our Company's then-CEO, Allen Leverett, suffered a stroke, following which the Board activated its executive succession plan. I stepped in as CEO during Mr. Leverett's recovery. Having served in that role from 2004 to 2016, the Board felt confident that my understanding of the Company -- and its operations, employees and investors -- would provide strong continuity as the Company continued to execute its short- and long-term plans.

Management succession was a clear focus in 2018. After Mr. Leverett's resignation as an officer of the Company, the Board appointed Kevin Fletcher, initially to serve as President of WEC Energy Group, followed by his transition into the added roles of CEO and a member of the Board of Directors, effective February 1, 2019. Mr. Fletcher has more than 40 years of experience in the energy industry, and the Board has the utmost confidence in his leadership capabilities. His deep experience in customer service and operations, combined with his previous responsibility for the operational and financial performance of all of the Company's utility subsidiaries, will enable him to contribute valuable Company and industry insights as a member of the Board.

In addition to appointing Mr. Fletcher to his new roles, the Board also appointed me to the position of Executive Chairman, and approved the creation of the Office of the Chair, solidifying a strong and seasoned leadership team. The Board believes this structure is appropriate to continue the smooth transition in leadership following Mr. Leverett's resignation as an active employee.

Financial and Operational Performance

By nearly every meaningful metric, 2018 was a record year for WEC Energy Group, and the Board was fully engaged in its oversight capacity throughout. Here are some results the Board believes are particularly noteworthy:

- Record earnings from operations and solid dividend growth;
- More cash returned to stockholders than any other year in Company history;
- Recognition as "most reliable" electric utility in the region and number one in the country for customer satisfaction among key accounts;
- Highest spending with diverse suppliers in Company history;
- Closure of nearly 1,500 megawatts of older, less efficient, coal-fired generation, reducing operating and maintenance costs by approximately $50 million annually;
- Increased dividend for 16th consecutive year (2004-2019); and
- Eleven all-time trading highs for WEC common stock.

This exceptional performance links directly to the Company's executive compensation structure and components, further demonstrating that our compensation program supports our annual and multi-year strategy. Our Board takes seriously its responsibility to ensure that executives truly are paid for performance in measurable, transparent, and meaningful ways.

Board Composition and Refreshment

The Board is able to carry out its fiduciary obligations to our stockholders because of the combined strength, diversity, and dedication of its individual members. Just as the Board focused considerable attention during 2018 on management succession, the Board continued to move forward with thoughtful refreshment.

Two new, independent directors joined our Board over the past 15 months. This provided a transition period as two highly experienced directors will complete their service on the Board at the 2019 Annual Meeting. We expect refreshment to continue, as five additional independent directors are scheduled to complete their service over the next two years.

We are committed to ensuring that the WEC Energy Group Board of Directors continues to be comprised of at least a two-thirds majority of independent directors, and that the Board as a whole remains significantly diverse, as it is today.

As always, on behalf of the Board, I invite your engagement and appreciate your support.



Gale E. Klappa
Executive Chairman

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Notice of 2019 Annual Meeting of Stockholders

We are pleased to invite you to join our Board of Directors and senior leadership at WEC Energy Group's 2019 Annual Meeting of Stockholders.

When and Where

Thursday, May 2, 2019, 10:00 a.m., Central time
Concordia University Wisconsin
R. John Buuck Field House
12800 North Lake Shore Drive
Mequon, WI 53097

Items of Business

1. Elect thirteen directors for terms expiring in 2020.
2. Provide advisory vote to approve compensation of the named executive officers.
3. Ratify Deloitte & Touche LLP as independent auditors for 2019.
4. Consider any other matters that may properly come before the meeting.

Record Date

The Board of Directors set February 21, 2019 as the record date for the meeting. This means that our stockholders as of the close of business on that date are entitled to receive this notice of the meeting and to vote at the meeting. On the record date, there were 315,450,338 shares of common stock of WEC Energy Group, Inc. issued and outstanding and entitled to vote at the meeting.

Meeting Attendance Information

If you plan to attend the Annual Meeting in person, you must pre-register and present photo identification at the door. See page P-76 for information about the location, format, and how to register to attend the meeting. Regardless of whether you plan to attend, please take a moment to vote your Proxy.

If you are unable to attend, you may view a live webcast on our website at www.wecenergygroup.com/invest/annualmtg.htm.



Margaret C. Kelsey
Executive Vice President,
General Counsel and Corporate Secretary
March 21, 2019

Voting Information

Please follow the instructions on your Notice Regarding the Availability of Proxy Materials, proxy card, or the information forwarded to you by your bank or broker, as applicable. The internet and telephone voting facilities will close at 10:59 p.m. Central time, on Wednesday, May 1, 2019.

Registered Stockholders of Record

You may vote using one of the following voting methods. Please make sure you have your proxy card in hand and follow the instructions.

ONLINE

Visit www.investorvote.com

or scan the QR code with your smart phone

BY PHONE

Call toll-free 800-652-8683

BY MAIL

Sign, date and return your proxy card

Stockholders who beneficially hold shares in street name through an intermediary on this date must obtain a legal proxy from their broker, bank or other nominee granting the right to vote.

All stockholders of record may vote in person at the meeting. Beneficial owners may vote in person at the meeting if they have a legal proxy, as described on page P-74.

If you receive paper copies of the proxy materials, please consider signing up to receive them electronically in the future by following the instructions contained on page P-76. By delivering our proxy materials electronically, we can provide our stockholders with the information they need in a more cost-effective and timely manner.

Important Notice Regarding the Availability of Proxy Materials for the Stockholder Meeting to Be Held on May 2, 2019 — The Proxy Statement and 2018 Annual Report are available at www.envisionreports.com/wec.

PROXY SUMMARY

This summary is intended to highlight certain information found within this proxy statement. This summary does not contain all of the information that you should consider. Please read the entire proxy statement before voting. Additional information regarding WEC Energy Group, Inc.'s (the "Company") 2018 performance can be found in the Company's Annual Report on Form 10-K for the year ended December 31, 2018.



Election of 13 Directors

The Board recommends a vote FOR each nominee listed below.

- Strong corporate governance practices consistently recognized with strong governance ratings.
- All candidates are highly regarded executives who possess strong integrity.
- Slate of candidates embodies diversity of knowledge, skills, experiences, gender, ethnicity, tenure and maturity.

See **pages P16-P22** for more information.

Name	Professional Principal Experience	Age	Director Since	Indep.
Barbara L. Bowles (Presiding Independent Director)	Retired Vice Chair, Profit Investment Management	71	1998	Yes
Albert J. Budney, Jr.	Retired President, Niagara Mohawk Holdings, Inc.	71	2015	Yes
Patricia W. Chadwick	President, Ravengate Partners, LLC	70	2006	Yes
Curt S. Culver	Non-Executive Chairman, MGIC Investment Corporation	66	2004	Yes
Danny L. Cunningham	Retired Partner and Chief Risk Officer, Deloitte & Touche LLP	63	2018	Yes
William M. Farrow III	Chairman, CEO and owner, Winston and Wolfe LLC	63	2018	Yes
Thomas J. Fischer	Principal, Fischer Financial Consulting LLC	71	2005	Yes
J. Kevin Fletcher	President and CEO, WEC Energy Group, Inc.	60	2019	No
Gale E. Klappa	Executive Chairman of the Board, WEC Energy Group, Inc.	68	2003	No
Henry W. Knueppel	Retired Chairman and CEO, Regal Beloit Corporation	70	2013	Yes
Allen L. Leverett	Former CEO and President, WEC Energy Group, Inc.	52	2016	No
Ulice Payne, Jr.	Managing Member, Addison-Clifton, LLC	63	2003	Yes
Mary Ellen Stanek	Managing Director & Director of Asset Management, Baird Financial Group	62	2012	Yes

Directors John Bergstrom and William Brodsky will complete their service as directors in 2019 and thus are not serving as nominees for election at the 2019 Annual Meeting. The Company sincerely thanks them for their many important contributions, leadership and years of dedicated service. Mr. Brodsky currently serves as a member of the Finance Committee. Mr. Bergstrom currently chairs the Compensation Committee and is a member of the Audit and Oversight Committee; the Board is finalizing its plan for appointing a new Compensation Committee Chair. See pages P29-P31 for more information on committee assignments.

BOARD COMPOSITION

Through its ongoing succession planning process, the Board seeks to maintain a composition of directors that collectively possess the skills and qualifications to provide effective oversight of the Company's strategic initiatives, financial and operational performance, and enterprise risks.

The 2019 director nominees are highly regarded leaders who possess strong integrity, and embody a diversity of knowledge, skills, experiences, gender, ethnicity, tenure, and maturity to effectively carry out the Board's oversight duties and responsibilities on behalf of the Company's stockholders and other stakeholders.

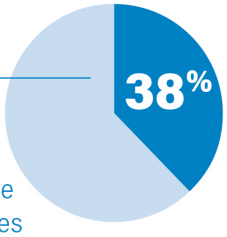
Director nominees by the numbers

(based upon 13 members)

10 Director nominees are **independent**

9 Director nominees are **current** or **former CEOs**

5 of 5 Director nominees on the Audit Committee are **financial experts**

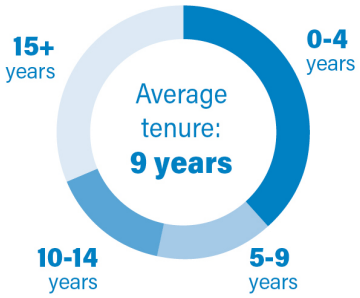


Female and/or ethnically diverse director nominees

3 Director nominees are **women**

3 Director nominees are **African American**

BALANCED TENURE



7 new directors since 2015

5 directors reach retirement age over the next 2 years

CORE COMPETENCIES – INTERMEDIATE TO ADVANCED KNOWLEDGE*

Audit/Financial Planning
CEO/Senior Leadership
Corporate Governance
Financial Strategy/Investment
Risk Management

100% of directors

Environment/CSR Matters
Government/Public Policy
Knowledge of Company's Industry
Regulated Industry Knowledge
Strategic Planning
Talent Management/Exec Comp
Technology/Security

> 75% of directors

* As reported by individual directors; see page P-15 for more information.

GOVERNANCE BEST PRACTICES

- Annual election of directors since 2005
- Ongoing Board succession planning
- Annual Board and committee evaluations
- Regular continuing education programs presented by internal and third-party experts
- Stock ownership requirements

INDEPENDENT BOARD AND COMMITTEES

- 10 of 13 independent directors
- Independent presiding director has specified duties
- Fully independent committee membership, except for the Executive Committee
- Executive sessions without management scheduled at each regular Board and committee meeting

ADVANCED SHAREHOLDER RIGHTS

- Majority vote standard for uncontested elections
- Bylaws include proxy access provision
- One-share, one-vote standard
- Special meeting provisions

PROPOSAL 2

Advisory Vote to Approve Compensation of the Named Executive Officers

The Board recommends a vote FOR the advisory vote on Executive Compensation.

- Our compensation program focuses on key Company results (financial, safety, customer satisfaction, diversity) that are aligned with our strategic goals.
- A substantial portion of compensation is at risk and tied to Company performance.
- The compensation program has a long-term orientation aligned with stockholder interests.

A comprehensive discussion of our executive compensation program, "Compensation Discussion and Analysis," begins on page P-35 of the Proxy Statement.

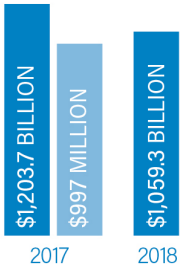
Our Business Performance

WEC Energy Group continued to achieve solid financial and operational results in 2018 while maintaining focus on the fundamentals - reliability, operating efficiency, financial discipline, customer care, and safety. As a result, the Company was able to deliver continued long-term value for our stockholders and customers.

FINANCIAL PERFORMANCE

Authorized Rate of Return
Each of our regulated utility subsidiaries earned its allowed rate of return in 2018

Net Income



Earnings per Share

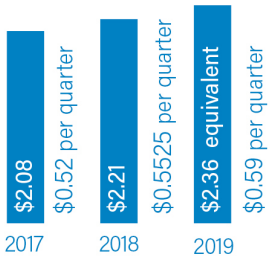


GAAP Adjusted

See Appendix A on page P-79 for reconciliation of non-GAAP measures

STOCKHOLDER RETURNS

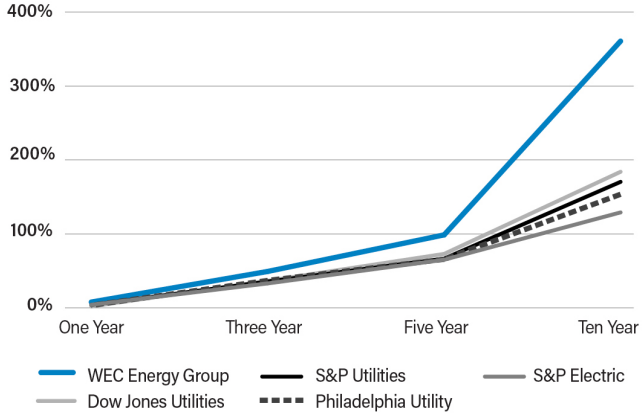
Dividends



76 consecutive years of delivering quarterly dividends (1942-2018)

16 consecutive years of dividend **increases** (2004-2019)

INDUSTRY-LEADING TOTAL STOCKHOLDER RETURNS



Source: Bloomberg; assumes all dividends are reinvested and returns are compounded daily.
See also the Five-Year Cumulative Return chart on page P-37.

NOTABLE ACHIEVEMENTS

WEC Energy Group named among 100 Best Corporate Citizens
Corporate Responsibility Magazine

WEC Energy Group presented with the 2018 Emergency Assistance Award
Edison Electric Institute

We Energies named most reliable utility in the Midwest for the eighth consecutive year
PA Consulting

We Energies named Veteran Friendly Workplace of the Year
USO Wisconsin

Our Executive Compensation Program

The Compensation Committee routinely evaluates the executive compensation program to ensure that it is competitive with respect to attracting and retaining key talent, linked to our financial and operational performance objectives, and aligned with industry best practices based upon input from stockholders and our compensation consultant. The Committee also takes into account prior say-on-pay results.

Best practices in executive compensation

- Aligned with long-term performance and business strategy
- Includes short- and long-term metrics, cash and equity; substantial portion at risk
- Annual say-on-pay advisory vote
- Independent compensation consultant
- Meaningful stock ownership requirements
- Clawback policy
- Anti-hedging and anti-pledging policy

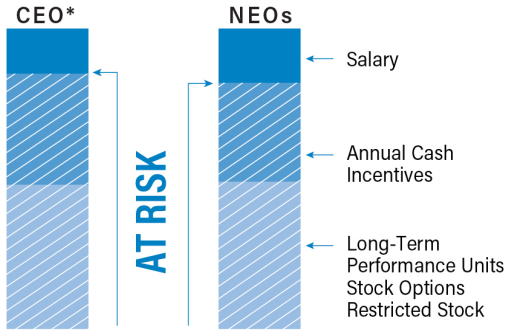
Compensation program links pay to performance

The executive compensation program has been designed so that total direct compensation ("TDC") is strongly tied to the achievement of our short-term and long-term goals. A substantial portion of pay is "at risk" and, generally, the value will only be realized upon a strong overall corporate performance.

	Salary	Annual Incentive	Performance Unit Plan	Stock Options and Restricted Stock
When Granted	Reviewed Annually			
Performance Type	Short-Term		Long-Term	
Award Type	Cash		Equity*	
Performance Period	Ongoing	1 year	3 Years	1 to 3 Year Vesting
How Payout is Determined	Role; responsibilities; market data; committee judgment	Formulaic: • Financial (EPS, cash flow, utility net income) • Operational (safety, customer satisfaction, diversity)	Formulaic: • TSR • Authorized ROE	Formulaic: Stock price performance

* Performance units are settled in cash.

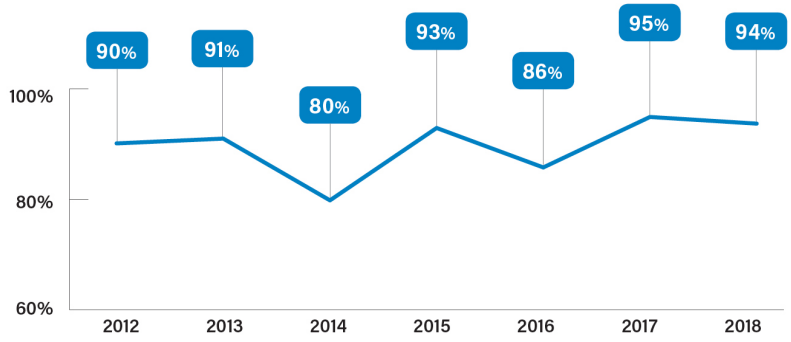
AT-RISK COMPENSATION



* Based upon metrics for Gale Klappa.

Approximately 85% of our CEO's TDC, and an average of 82% of the other NEOs' TDC, is tied to Company performance and not guaranteed.

SAY-ON-PAY "FOR" VOTE



We maintain a largely consistent approach to our compensation program from year to year, while also responding to stockholder feedback. Historically, this has resulted in favorable approval ratings of our annual advisory say-on-pay proposal.

PROPOSAL 3

Ratification of Deloitte & Touche LLP as Independent Auditors for 2019

The Board recommends a vote FOR ratification of Deloitte & Touche LLP as independent auditors for 2019

- The Audit Committee annually evaluates the performance of Deloitte & Touche LLP and confirms that retention is in the best interests of the Company and its stockholders.
- Deloitte & Touche LLP is an independent firm with significant industry and financial reporting expertise, and fees that are appropriate for the size and scope of the Company.

See **pages P69-P71** for more information.

PROXY STATEMENT

This proxy statement is being furnished to stockholders beginning on or about March 21, 2019, in connection with the solicitation of proxies by the WEC Energy Group, Inc. ("WEC Energy Group" or the "Company") Board of Directors (the "Board") to be used at the Annual Meeting of Stockholders on Thursday, May 2, 2019 (the "Meeting") at 10:00 a.m., Central time, at Concordia University Wisconsin in the R. John Buuck Field House located at 12800 North Lake Shore Drive, Mequon, Wisconsin 53097, and at all adjournments or postponements of the Meeting, for the purposes listed in the Notice of 2019 Annual Meeting of Stockholders.

PROPOSAL 1: ELECTION OF DIRECTORS – TERMS EXPIRING IN 2020

WEC Energy Group's bylaws require each director to be elected annually to hold office for a one-year term. This is an uncontested election; therefore, our majority vote standard for election of directors will apply. Under this standard, the director nominees will be elected only if the number of votes cast favoring such nominee's election exceeds the number of votes cast opposing that nominee's election, as long as a quorum is present. Therefore, presuming a quorum is present, shares not voted, whether by broker non-vote, abstention, or otherwise, have no effect in the election of directors. Proxies may not be voted for more than 13 persons in the election of directors.

Acting on the recommendation of the Corporate Governance Committee, the Board's nominees for election are:

Barbara L. Bowles	**J. Kevin Fletcher**
Albert J. Budney, Jr.	**Gale E. Klappa**
Patricia W. Chadwick	**Henry W. Knueppel**
Curt S. Culver	**Allen L. Leverett**
Danny L. Cunningham	**Ulice Payne, Jr.**
William M. Farrow III	**Mary Ellen Stanek**
Thomas J. Fischer	

- Each nominee has consented to being nominated and to serve if elected. In the unlikely event that any nominee becomes unable to serve for any reason, the proxies will be voted for a substitute nominee selected by the Board upon the recommendation of the Corporate Governance Committee of the Board.
- Directors John F. Bergstrom and William J. Brodsky complete their service as directors in 2019 and thus will not serve as nominees for re-election at the 2019 annual meeting of stockholders. The Company sincerely thanks them for their many important contributions, leadership and years of dedicated service.

In selecting the 2019 director nominees, the Corporate Governance Committee and the Board determined that the candidates collectively embody a wide body of characteristics germane to executing the duties of the Board, including the general criteria, qualifications, diversity, and independence reported below, and which are described in more detail for each director in his/her respective biographies found under the heading, "2019 Director Nominees for Election."

The Board of Directors recommends that you vote "FOR" all of the director nominees.

DIRECTOR NOMINATION AND EVALUATION PROCESS

Nomination Process

Candidates for director nomination may be proposed in a number of ways, including by stockholders, the Corporate Governance Committee, and other members of the Board. The Corporate Governance Committee may pay a third party to identify qualified candidates; however, no such firm was engaged with respect to the nominees listed in this proxy statement.

The Corporate Governance Committee will consider director candidates recommended by stockholders provided that the stockholders submitting recommendations comply with requirements and procedures set forth in our bylaws. Stockholders may also nominate director candidates by following the procedures outlined on P-78. No formal stockholder nominations or recommendations for director candidates were received in connection with the 2019 Annual Meeting.

Evaluation Process

The Corporate Governance Committee evaluates director candidates, including those proposed by stockholders, through the lens of its ongoing director succession planning process, whereby the Corporate Governance Committee ensures that the Board is composed of directors who embody certain minimum criteria, and who, as a group, have the skills and experiences to effectively oversee management's strategy for operating in a complex industry while performing their fiduciary obligations.

When a person is initially identified as a potential candidate, the Corporate Governance Committee may collect and review publicly available information regarding the person to assess whether that person should be considered further. If the Corporate Governance Committee determines that the candidate warrants further consideration, the chair or another member of the Board of Directors contacts the person. Generally, if the person expresses a willingness to be considered and to serve on the Board, the Corporate Governance Committee requests additional information from the candidate, reviews the person's accomplishments and qualifications, and conducts one or more interviews with the candidate. In certain instances, Corporate Governance Committee members may contact one or more references provided by the candidate, or may contact other members of the business community or other persons who may have greater firsthand knowledge of the candidate. The Committee will utilize third parties if and as needed to assist with these activities. As a final step, the candidate interviews with members of the Board, following which the Corporate Governance Committee will propose a recommendation regarding nomination to the Board for its discussion and final determination.

Director Term Limits

The Board does not believe it is appropriate or necessary to limit the number of terms a director may serve. The Board values the participation and insight of directors who have developed an increased understanding of the governance of the Company and the specific issues it faces doing business in a complex, regulated industry, as well as those directors who bring fresh and varied perspectives, resulting in a Board with a balanced tenure.

DIRECTOR QUALIFICATIONS

The Corporate Governance Committee and the Board evaluate director nominees in light of the Board's current members, with the goal of recommending nominees with diverse backgrounds and experiences who, together with the current directors, can best perpetuate the success of WEC Energy Group's business and represent stockholder interests. By adhering to a philosophy whereby director nominees are evaluated on the basis of certain minimum qualifications, Board diversity, and core competencies, the Board is able to attract director candidates that bring a broad range of perspectives and experiences, and who will effectively contribute to and complement the Board.

Key factors considered in recommending the 2019 director nominees are listed below:

- To be eligible for consideration, the Board believes that any proposed candidate must demonstrate certain minimum qualifications, which the Corporate Governance Committee reviews annually:

• Proven integrity	• Mature and independent judgment	• Vision and imagination
• Ability to objectively appraise problems	• Ability to evaluate strategic options/ risks	• Sound business experience/acumen
• Relevant technological, political, economic, or social/culture experience	• Social consciousness	• Achievement of prominence in career
• Familiarity with national and international issues affecting the Company's business	• Contribution to the Board's desired diversity and balance	• Availability to serve for five years before reaching the directors' retirement age of 72 (in the case of new directors)

- While the Corporate Governance Committee does not have a specific policy with regard to the consideration of diversity in identifying director nominees, it strives to cast a wide net and recommend candidates who each bring a unique perspective to the Board in order to contribute to a collective diversity - diversity of knowledge, skills, experiences, thought, gender, ethnicity, tenure, and maturity.



- Directors' qualifications are also evaluated in the context of the Board's strategic initiatives, financial and operational performance objectives, and material risks. With that in mind, the Corporate Governance Committee and Board have determined through the Board succession planning process that the Board's composition should consist of candidates that collectively possess a specific set of core competencies as listed in the Proxy Summary on P-10, in order to effectively carry out its oversight function.

  During the third quarter of 2018, the Corporate Governance Committee and Board evaluated and affirmed this set of competencies. Each director then performed a self-assessment of his/her level of knowledge in each skill area using the following 3-point scale: "1" Limited knowledge (e.g., no direct experience, primary exposure comes from Board or Committee reports); "2" Intermediate knowledge (e.g., general managerial/oversight experience or broad exposure as a Board or Committee member); "3" Advanced knowledge (e.g., direct experience; subject matter expert). A summary of the Board's level of knowledge with respect to each of the core competencies was included in the Proxy Summary on page P-10. At least one director possesses advanced knowledge in each core competency.

DIRECTOR INDEPENDENCE

The guidelines the Board uses in determining director independence are located in Appendix A of the Corporate Governance Guidelines ("Guidelines"), which are available on the Corporate Governance section of our Company's website at www.wecenergygroup.com/govern/governance.htm. These Guidelines provide that the Board should consist of at least a two-thirds majority of independent directors. The independence standards found in our Guidelines are not only in compliance with the listing standards of the New York Stock Exchange ("NYSE"), but are actually more stringent than the NYSE rules. In order to be deemed independent, the individual must have no material relationship with the Company that would interfere with the exercise of good judgment in carrying out his or her responsibilities as a director.

Prior to initial and annual election, all directors complete a detailed questionnaire that elicits information that is used to ensure compliance with the Board's and the NYSE's standards of independence. The Corporate Governance Committee also reviews potential conflicts of interest, including related-party transactions, interlocking directorships, and substantial business, civic, and/or social relationships with other members of the Board that could impair the prospective Board member's ability to act independently from the other Board members and management. The Board also considers whether a director's immediate family members meet the independence criteria outlined in the Guidelines, as well as whether a director has certain relationships with WEC Energy Group's affiliates, when determining the director's independence.

The Board has affirmatively determined that Directors Bergstrom, Bowles, Brodsky, Budney, Chadwick, Culver, Cunningham, Farrow, Fischer, Knueppel, Payne, and Stanek are independent. Directors Klappa, Fletcher, and Leverett are not independent due to their employment with the Company.

Director Stanek. Since 2005, WEC Energy Group has engaged Baird Financial Group primarily to provide consulting services for investments held in the Company's various benefit plan trusts. The Board reviewed the terms of this engagement, including the approximately $680,000 in fees paid to Baird in 2018 (which are less than one-tenth of 1% of Baird's total revenue), and Ms. Stanek's position at Baird, and concluded that such engagement is not material and did not impact Ms. Stanek's independence. Ms. Stanek is not involved with and does not consult on the contract with or recommendations made by Baird and receives no direct financial benefit from these services. WEC Energy Group management evaluates Baird's services against market standards for overall quality and value on a regular basis. Neither the Board nor Ms. Stanek plays a role in the retention of Baird for these services or any related negotiation of commercial terms. In addition, WEC Energy Group's pension trusts and other benefit accounts do not hold any investments in Baird funds.

2019 DIRECTOR NOMINEES FOR ELECTION

The following 13 individuals have been nominated for election to the Board of Directors at the WEC Energy Group Annual Meeting. Biographical information for each director nominee is set forth below. Ages are as of January 17, 2019, the date each person was designated as a nominee of the Board for election at the Meeting.



Barbara L. Bowles

Age: 71

Director Since: 1998

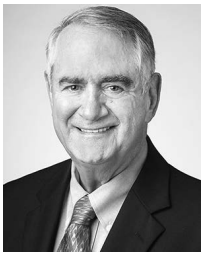
Board Committees: Audit and Oversight; Corporate Governance (Chair); Executive

WEC Board: Independent Presiding Director

- Profit Investment Management LLC - Retired Vice Chair. Served as Vice Chair from January 2006 until retirement in December 2007. Profit Investment Management is an investment advisory firm.
- The Kenwood Group, Inc. - Retired Chairman. Served as Chairman from 2000 until 2006 when The Kenwood Group, Inc. merged into Profit Investment Management. CEO from 1989 to 2005.
- Director of Hospira, Inc. from 2008 to 2015.
- Director of WEC Energy Group since 1998; Director of Wisconsin Electric Power Company (subsidiary of WEC) from 1998 to June 2015.

Core competencies, qualifications and experience

As founder, CEO, and retired Chairman of The Kenwood Group, Inc., a Chicago-based investment advisory firm that managed pension funds for corporations, public institutions, and endowments, Ms. Bowles, who is a Chartered Financial Analyst, brings over 20 years of investment advisory experience to our Board of Directors. Having also served as a portfolio manager and utility analyst for more than 10 years, and as a chief investor relations officer for two Fortune 50 companies, she contributes valuable perspective as to what issues matter to large investors. In the role of Chief Compliance Officer of Profit Investment Management, Ms. Bowles gained a deep understanding of corporate governance issues and concerns, experience she applies to her positions as Chair of WEC Energy Group's Corporate Governance Committee and independent presiding director. She also contributes valuable risk management and financial reporting insights as a member of the Audit and Oversight Committee, expertise she developed from current and past service as a director on the boards of several other public companies where she has served on the audit and finance committees. With utility subsidiaries located in Chicago, the Board of Directors also benefits from the economic and political perspectives Ms. Bowles provides as a result of her involvement in several important non-profit organizations in Chicago.



Albert J. Budney, Jr.

Age: 71

Director Since: 2015

Board Committee: Corporate Governance

- Niagara Mohawk Holdings, Inc. - Retired President and Director. Served as President and Director from 1999 to 2002. Niagara Mohawk Holdings, Inc. is a holding company whose subsidiaries distribute electricity in New York.
- Director of WEC Energy Group since June 2015; Director of Integrys Energy Group from February 2007 to June 2015.

Core competencies, qualifications and experience

With over 40 years of utility experience in senior leadership positions, Mr. Budney brings to our Board of Directors extensive knowledge in managing the operations of a utility company and the complexities that arise from operating in a highly-regulated industry. He has acquired considerable board experience in utility industry mergers and acquisitions having served as a director of Niagara Mohawk Holdings when it was acquired by National Grid and of Integrys Energy Group when it was acquired by the Company. Mr. Budney brings to the Board knowledge of environmental issues that he gained as President of Niagara Mohawk Holdings while supervising the Vice President of Environmental Affairs. This provided Mr. Budney with experience he applied as a founding member of the Environmental Committee of the Board at Integrys Energy Group prior to its acquisition by WEC Energy Group. Having also served as the Chair of the Corporate Governance Committee and lead director of Integrys Energy Group, Mr. Budney's broad knowledge in governance, corporate management, and strategic planning matters are very valuable to the Board in carrying out its oversight in these areas.



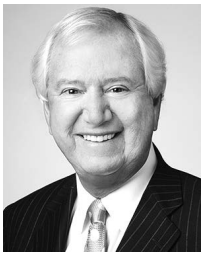
Patricia W. Chadwick

Age: 70
Director Since: 2006
Board Committees: Audit and Oversight; Finance

- Ravengate Partners, LLC - President since 1999. Ravengate Partners, LLC provides businesses and not-for-profit institutions with advice about the financial markets, business management, and global economics.
- Director of AMICA Mutual Insurance Company since 1992; Director of VOYA Mutual Funds (previously ING Mutual Funds) since 2006; Director of The Royce Funds since 2009.
- Director of WEC Energy Group since 2006; Director of Wisconsin Electric Power Company (subsidiary of WEC) from 2006 to June 2015.

Core competencies, qualifications and experience

Ms. Chadwick, who is a Chartered Financial Analyst, brings to our Board of Directors extensive investment management expertise gained from more than 30 years of experience as an investment professional, portfolio manager or principal. As founder and President of Ravengate Partners, a firm that has been educating and advising businesses and not-for-profit institutions about the financial markets and global macro economy since 1999, Ms. Chadwick's insights into the investment industry's perspectives is valuable to the Board's financial planning and strategy discussions. Her knowledge of capital markets is particularly helpful to WEC Energy Group and its subsidiaries, which operate in a capital intensive industry and consistently access the capital markets. Ms. Chadwick serves as a director and committee member on the boards of two registered investment companies, VOYA Mutual Funds and The Royce Funds, through which she has developed extensive governance experience with respect to audit oversight and financial reporting. As a board director and Finance Committee member of AMICA Mutual Insurance Company, she has gained a deep understanding of insurance risk management and oversight matters, which is valuable experience that she applies to her role on the WEC Energy Group Finance Committee.



Curt S. Culver

Age: 66
Director Since: 2004
Board Committees: Corporate Governance; Finance (Chair)

- MGIC Investment Corporation - Non-Executive Chairman of the Board since March 2015. Served as Chairman from 2005 to February 2015, CEO from 2000 to February 2015, and President from 1999 to 2006. MGIC Investment Corporation is the parent of Mortgage Guaranty Insurance Corporation.
- Mortgage Guaranty Insurance Corporation - Non-Executive Chairman of the Board since March 2015. Served as Chairman from 2005 to February 2015, CEO from 1999 to February 2015, and President from 1996 to 2006. Mortgage Guaranty Insurance Corporation is a private mortgage insurance company.
- Director of MGIC Investment Corporation since 1999.
- Director of WEC Energy Group since 2004; Director of Wisconsin Electric Power Company (subsidiary of WEC) from 2004 to June 2015.

Core competencies, qualifications and experience

Having served for 15 years as the CEO of Mortgage Guaranty Insurance Corporation and its parent company, MGIC Investment Corporation, Mr. Culver brings to our Board of Directors a strong working knowledge of the strategic, economic, and public policy issues facing a large, regulated, publicly-held company headquartered in Milwaukee, Wisconsin. His expertise in risk management and oversight is particularly valuable in his service as chair of the Finance Committee, while his insurance industry experience puts him in a position to lead the Committee's evaluation of the Company's overall risk management program. Mr. Culver's broad corporate governance experience, developed from his extensive past and present service on the MGIC boards, as well as several highly-visible Milwaukee-area non-profit entities and two private for-profit organizations, is of great value to the Board as it carries out its oversight responsibilities.



Danny L. Cunningham

Age: 63
Director Since: 2018
Board Committees: Audit and Oversight

- Deloitte & Touche LLP - Retired Partner and Chief Risk Officer. Served as Partner from 2002 to 2015 and as Chief Risk Officer from 2012 to 2015. Deloitte & Touche LLP is an industry-leading audit, consulting, tax, and advisory firm.
- Director of Actuant Corporation since 2016.
- Director of WEC Energy Group since January 2018.

Core competencies, qualifications and experience

Mr. Cunningham brings to our Board of Directors more than 30 years of experience serving public audit clients in a broad array of industries, including manufacturing, printing, process, software, and financial services, as well as a deep understanding of the business, economic, compliance, and governmental environment in which the Company and many of the Company's major customers operate. Mr. Cunningham's strong expertise in financial reporting, internal controls, and audit functions are of great value to the Board as it fulfills its responsibility for oversight of the Company's accurate preparation of financial statements and disclosures, and compliance with legal and regulatory requirements. Having served as chief risk officer at Deloitte & Touche LLP, he gained keen insights into the complexities of risk management, through which he applies his expertise in assessing the effectiveness of the Company's practices and policies to mitigate enterprise-wide risks. Mr. Cunningham's multi-national experience brings the added diversity of a global perspective to the Board as it evaluates its strategic objectives, while his past service on the boards of several major Milwaukee-area not-for-profit organizations equips him to contribute thoughtful insights on issues impacting the city's culture, workforce, and economic vitality.



William M. Farrow III

Age: 63
Director Since: 2018
Board Committees: Finance

- Winston and Wolfe, LLC - Chairman and Chief Executive Officer since 2010. Winston and Wolfe LLC is a privately held technology development and advisory company.
- Urban Partnership Bank - Retired President and CEO from August 2010 to January 2018. UPB provides financial services in moderate income communities located in Chicago, Detroit and Cleveland.
- Director of CBOE Global Markets Inc. since 2016; Director of Echo Global Logistics Inc. since 2017.
- Director of WEC Energy Group since January 2018.

Core competencies, qualifications and experience

Mr. Farrow brings to our Board of Directors 40 years of senior leadership experience in managing business operations, technology development, enterprise risk and strategy. His extensive professional experience in the banking and financial markets, accompanied by knowledge acquired from his service on the boards of CBOE Global Markets and the Federal Reserve Bank of Chicago, enables him to add significant value to the Board's oversight of the Company's financial management strategy. His first-hand experience and perspectives in addressing advances in information technology, as well as the experience he's gained as a current board member on the Audit Committee for both CBOE Global Markets and Echo Global Logistics, is particularly valuable to the Board as WEC Energy Group companies address complex risks, including those associated with protecting operating systems and assets against physical and cyber threats. Having spent his career in the City of Chicago, Mr. Farrow is also able to provide the Board with economic and public policy insight as it relates to conducting business in Chicago, which is further enhanced by the strong relationships he has developed with key leaders while serving on the boards of several highly-visible Chicago-area private, not-for-profit and community organizations. This is especially important given the sizable, long-term construction project that is underway by the Company's Illinois utility subsidiary to modernize the natural gas infrastructure in the City of Chicago, which requires ongoing collaboration with city and state government officials and regulatory agencies.



Thomas J. Fischer

Age: 71

Director Since: 2005

Board Committees: Audit and Oversight (Chair); Compensation; Executive

- Fischer Financial Consulting LLC - Principal since 2002. Fischer Financial Consulting LLC provides consulting on corporate financial, accounting, and governance matters.
- Director of Actuant Corporation from 2003 to January 2017; Director of Badger Meter, Inc. since 2003; Director of Regal Beloit Corporation since 2004.
- Director of WEC Energy Group since 2005; Director of Wisconsin Electric Power Company (subsidiary of WEC) from 2005 to June 2015.

Core competencies, qualifications and experience

Mr. Fischer provides our Board of Directors with significant expertise in accounting and auditing matters, including financial reporting and regulatory compliance, risk assessment and management, and corporate governance issues. His experience in these areas comes from 33 years of work at Arthur Andersen, a large, international independent accounting firm, where for 22 years, he served as a partner responsible for services provided to large, complex public and private companies and several public utility audits. Since 2002, Mr. Fischer has provided consulting services to companies in the areas of corporate financial, accounting, and governance matters. Mr. Fischer, who is a Certified Public Accountant, brings extensive knowledge and experience to his responsibilities as WEC Energy Group's Audit and Oversight Committee Chair as a result of his past and present service on several other audit committees at public companies based in Wisconsin. His significant expertise is invaluable to WEC Energy Group's Board as it navigates a complex and evolving regulatory compliance landscape.



J. Kevin Fletcher

Age: 60

Director Since: 2019

- WEC Energy Group, Inc. - CEO since February 2019; President since October 2018.
- Wisconsin Electric Power Company (subsidiary of WEC) - Chairman of the Board and Chief Executive Officer since February 2019; President from May 2016 to November 2018; Executive Vice President-Customer Service and Operations from June 2015 to May 2016; Senior Vice President-Customer Operations from October 2011 to June 2015.
- Director of WEC Energy Group, Inc. since February 2019; Director of Wisconsin Electric Power Company since June 2015.
- Mr. Fletcher also serves as an executive officer and/or director of several other major subsidiaries of WEC Energy Group.

Core competencies, qualifications and experience

Mr. Fletcher has more than 40 years of experience working in the public utility industry, including nearly 25 years at a senior leadership level. Prior to joining the Company in 2011, Mr. Fletcher served as Senior Vice President-Community and Economic Development at Georgia Power, the largest subsidiary of The Southern Company, a public utility holding company serving the southeastern United States. During his 34-year career with Southern Co., 16 of those years as an officer, Mr. Fletcher held leadership positions in operations, customer service, marketing and sales. When he first joined WEC Energy Group, he served as Senior Vice President-Customer Operations of its utility subsidiaries, with overall responsibility for the planning, engineering, construction, operation and maintenance of the Company’s electric and natural gas distribution systems in Wisconsin and Michigan’s Upper Peninsula. In May 2016, he was appointed to serve as President of the Company’s Wisconsin utility subsidiaries, and assumed responsibilities as President of the Company’s Minnesota and Michigan utility subsidiaries in September 2018. In October 2018, Mr. Fletcher was appointed President of WEC Energy Group, followed by his appointment to CEO in February 2019, whereby he has financial and operational responsibility for all of the Company's utility subsidiaries. He also has held responsibility for the supplier diversity initiative across all of the Company’s utilities. With his extensive experience in business operations, customer service, and senior leadership of publicly regulated utilities, Mr. Fletcher contributes substantive insight into the Company’s industry and customers, to the management team, and to the Board.



Gale E. Klappa

Age: 68
Director Since: 2003
Board Committee: Executive (Chair)

- WEC Energy Group, Inc. - Executive Chairman since February 2019; Chairman of the Board and CEO from 2004 to May 2016 and October 2017 to February 2019; Non-Executive Chairman of the Board from May 2016 to October 2017; President from 2003 to August 2013.
- Wisconsin Electric Power Company (subsidiary of WEC) - Chairman of the Board from 2004 to May 2016 and January 2018 to February 2019; CEO from 2003 to May 2016 and January 2018 to February 2019; President from 2003 to June 2015.
- Director of Associated Banc-Corp since 2016 and Director of Badger Meter, Inc. since 2010, both headquartered in Wisconsin; Director of Joy Global Inc. from 2006 to 2017.
- Director of WEC Energy Group, Inc. since 2003; Director of Wisconsin Electric Power Company from 2003 to May 2016 and January 2018 to present.
- Mr. Klappa also serves a director of several other major subsidiaries of WEC Energy Group.

Core competencies, qualifications and experience

Mr. Klappa has more than 40 years of experience working in the public utility industry, including more than 25 at a senior executive level. He retired as the Company's CEO in May 2016, at which time he assumed the role of Non-Executive Chairman of the Board. Prior to joining the Company in 2003, Mr. Klappa served in various executive leadership roles at The Southern Company, a public utility holding company serving the southeastern United States. Under his leadership, WEC Energy Group successfully completed its 2015 acquisition of Integrys Energy Group, which nearly doubled the employee and customer population, and increased the Company's geographic footprint to four states. With his extensive experience in the business operations and C-suite leadership of publicly regulated utilities, his service as a board member for several other public companies, and his contributions to significant economic development initiatives in southeastern Wisconsin, Mr. Klappa has led the Board with a deep understanding of the financial investment decisions and public policy issues facing large public companies. In October 2017, after the Company's then-CEO, Allen Leverett, suffered a stroke, the Board appointed Mr. Klappa to serve in the role of CEO, while also having him retain his role of Board Chairman. With the appointment of Mr. Fletcher as CEO effective February 2019, Mr. Klappa now serves as Executive Chairman. Mr. Klappa's deep knowledge of the Company's industry, customers, stockholders, and management team is of great value to the Board.



Henry W. Knueppel

Age: 70
Director Since: 2013
Board Committees: Audit and Oversight; Corporate Governance

- Regal Beloit Corporation - Retired Chairman of the Board and CEO. Served as CEO from 2005 to 2011 and as Chairman from 2006 to 2011. Regal Beloit Corporation is a leading manufacturer of electric motors, mechanical and electrical motion controls, and power generation products.
- Harsco Corporation - Independent, Non-Executive Chairman of the Board from September 2012 until September 2014. Served as Interim Chairman and CEO from February 2012 to September 2012 and Director from 2008 to April 2016. Harsco Corporation is a diversified, worldwide industrial services company.
- Director of Regal Beloit Corporation since 1987; Director of Snap-on Incorporated since 2011.
- Director of WEC Energy Group since 2013; Director of Wisconsin Electric Power Company (subsidiary of WEC) from 2013 to June 2015.

Core competencies, qualifications and experience

With more than 30 years of senior management experience at Regal Beloit Corporation, including five years as the combined Chairman of the Board and CEO, Mr. Knueppel brings extensive executive management experience to our Board of Directors, including strategic planning, financial strategy and talent management perspective. Regal Beloit Corporation is a Wisconsin-based manufacturer of electrical motors, mechanical and electrical motion controls, and power generation products, which gives Mr. Knueppel knowledge of key equipment used in the Company's operations. He currently serves on the boards of several large, publicly-traded industrial companies and provides the Board with perspective on operational matters the Company faces in serving its large commercial and industrial customers. Mr. Knueppel also brings to the Board a wide range of knowledge and experience in corporate governance, having served for more than 30 years as a director for several publicly-traded companies, including his role as the independent, non-executive chairman of the board of Harsco Corporation.



Allen L. Leverett

Age: 52
Director Since: 2016

- WEC Energy Group, Inc. - President from August 2013 to October 2018; CEO from May 2016 to October 2017; Executive Vice President from 2004 through July 2013; CFO from 2003 until 2011. Mr. Leverett also served as the principal executive officer of WEC Energy Group's generation operations from 2011 to May 2016.
- Wisconsin Electric Power Company (subsidiary of WEC) - Chairman of the Board and CEO from May 2016 through December 2017; President from June 2015 to May 2016; Executive Vice President from 2004 through June 2015; CFO from 2003 until 2011.
- Director of WEC Energy Group since January 2016; Director of Wisconsin Electric Power Company from June 2015 to January 2018.

Core competencies, qualifications and experience

Having worked in the public utility industry for nearly 25 years, Mr. Leverett has a deep understanding of the complexities of the Company's industry, operations, and regulatory environment, while having built extensive senior leadership experience. Mr. Leverett served in executive positions at Georgia Power and Southern Company Services, where he held overall responsibility for financial planning and analysis, capital markets and leasing, treasury, and investor relations. He joined WEC Energy Group in 2003 as CFO and proceeded to hold numerous executive positions, including President and CEO of the Company's power generation group, with overall responsibility for the electric generation portfolio, fuel procurement, environmental compliance, and renewable energy development strategy. Following the Company's acquisition of Integrys Energy Group in June 2015, Mr. Leverett served as President of the Company's utilities located in Wisconsin, Michigan, and Minnesota through early 2016. Effective May 1, 2016, Mr. Leverett was appointed as CEO of WEC Energy Group and served in that role until October 2017, when he suffered a stroke and began a medical leave of absence. In October 2018, Mr. Leverett resigned as President of the Company, while retaining his role as a member of the Board. Mr. Leverett's experience and insights in running a regulated public company serve as critical inputs to the Board's oversight of the Company's long-term strategic plan.



Ulice Payne, Jr.

Age: 63
Director Since: 2003
Board Committees: Compensation; Executive; Finance

- Addison-Clifton, LLC - Managing Member since 2004. Addison-Clifton, LLC provides global trade compliance advisory services.
- Director of Foot Locker, Inc. since December 2016; Director of Manpower Group since 2007; Trustee of The Northwestern Mutual Life Insurance Company since 2005.
- Director of WEC Energy Group since 2003; Director of Wisconsin Electric Power Company (subsidiary of WEC) from 2003 to June 2015.

Core competencies, qualifications and experience

Mr. Payne brings to our Board of Directors strong senior leadership and public service experience within the greater Milwaukee community and State of Wisconsin, having previously served in roles that included the Securities Commissioner for the State of Wisconsin, managing partner of the Milwaukee office of the law firm Foley & Lardner LLP, and president and CEO of the Milwaukee Brewers Baseball Club, Inc. In addition, Mr. Payne is involved in numerous Milwaukee-area non-profit entities, making him well-positioned to provide the Board with perspective on the economic and social issues affecting the greater Milwaukee area, as well as a broad spectrum of the Company's customers. As founder and President of Addison-Clifton, LLC, which provides global trade compliance consulting, Mr. Payne understands the importance of providing clients with exceptional customer service, a focus that is critical to execution of WEC Energy Group's strategic initiatives. Mr. Payne also contributes valuable financial and risk assessment insights gained throughout his career, including from his past and present service on the boards of several public companies, for which he has served as a member of the Audit, Finance, and/or Corporate Governance committee at each of these companies.



Mary Ellen Stanek

Age: 62
Director Since: 2012
Board Committee: Finance

- Baird Financial Group - Managing Director and Director of Asset Management since 2000. Baird Financial Group provides wealth management, capital markets, private equity, and asset management services to clients worldwide.
- Baird Advisors - Chief Investment Officer since 2000. Baird Advisors is an institutional fixed income investment advisor.
- Baird Funds, Inc. - President since 2000. Baird Funds is a publicly registered investment company.
- Trustee of The Northwestern Mutual Life Insurance Company since 2009.
- Director of Journal Media Group, Inc. and its predecessor companies from 2002 to April 2016.
- Director of WEC Energy Group since 2012; Director of Wisconsin Electric Power Company (subsidiary of WEC) from 2012 to June 2015.

Core competencies, qualifications and experience

Ms. Stanek, who is a Chartered Financial Analyst, brings to our Board of Directors extensive financial and investment strategy expertise, resulting from over 40 years of investment management experience. As Managing Director and Director of Asset Management of Baird Financial Group, a position she has held since 2000, Ms. Stanek's expertise in fixed income investments provides the Board and management with invaluable financial strategy insight relative to WEC Energy Group and its subsidiaries, which customarily issue debt securities as a means of raising capital. As a member of the WEC Energy Group Finance Committee, she also offers valuable perspective on insurance risk matters, having served for 15 years as a director of West Bend Mutual Insurance Company. In addition to her recognition as a prominent business leader in Milwaukee's financial community, Ms. Stanek has dedicated significant time to serving on the boards of a large number of Milwaukee-area non-profit organizations, through which she has developed strong relationships with key community leaders and stakeholders. From these experiences, she brings the Board insightful perspectives on issues impacting the culture and viability of today’s workforce.

GOVERNANCE

Accountability to stockholders is critical to the Company's long-term success. We have mechanisms in place to ensure that management and the Board hear, understand, and consider the issues that matter most to our stockholders. This ongoing engagement provides valuable insight into how our stockholders view the Company's practices and policies, shapes the processes used to evaluate goals and expectations, and identifies emerging issues that may affect our corporate governance and compensation practices.

STOCKHOLDER ENGAGEMENT

Under the Board's oversight, Company leadership regularly engages with investors to discuss business results, strategic direction, and corporate governance and compensation practices through a year-round stockholder engagement program. The Company's outreach and engagement program took many forms during 2018:

- Direct engagement by senior management with the Company's stockholders to discuss issues of interest, including corporate governance, executive compensation, and corporate responsibility practices. These conversations are reported to the Board and are taken into consideration when reviewing and modifying governance and compensation practices and policies.
- Investor presentations conducted at analyst meetings and investor conferences across the U.S., Canada, and Europe.
- CEO, CFO, and other senior management meetings and conference calls with stockholders to discuss corporate strategy, financial and business performance, and to update stockholders on key developments.
- Invitations to investors to listen to Webcasts of the Annual Meeting and quarterly earnings conference calls, and to view the annual report, news releases, Securities and Exchange Commission ("SEC") filings, and other significant corporate publications on our Website.
- The opportunity to attend and voice opinions at our Annual Meeting.
- The ability for stockholders to submit stockholder proposals and director nominees, and to formally nominate director candidates using proxy access as permitted under our bylaws.
- Annual election of directors, who are elected by majority vote in uncontested elections.
- Annual advisory vote on our executive compensation program ("say-on-pay").
- Strong Board committee structure, which allows the Board to focus on issues that matter most to our stockholders, including consideration of previous stockholder votes on say-on-pay, director elections, and other matters when developing policies and practices.
- Process for stockholders to directly correspond with individual directors via the Corporate Secretary page P-31.

Below is a summary of our yearly corporate governance practices related to stockholder engagement on environmental, social and governance ("ESG") topics.

SUMMER	FALL	WINTER	SPRING
• Review results from Annual Meeting of Stockholders • Engage with stockholders to discuss voting results • Conduct annual assessment of corporate governance practices to identify potential areas of focus • Discuss voting results, investor feedback, and annual assessment with Board	• Meet with institutional investors to discuss our governance and compensation practices and to address questions or concerns • Consider enhancements to our practices and disclosures based on investor feedback • Share investor feedback and recommendations for changes in practices and disclosures with Board committees and full Board	• Approve any changes to corporate governance and compensation practices • Develop disclosures for the proxy statement	• Publish annual disclosure documents (Form 10-K, Annual Report, Proxy Statement) • Hold Annual Meeting of Stockholders

CORPORATE GOVERNANCE FRAMEWORK

Corporate Governance Guidelines

In 1996, WEC Energy Group became one of the earliest adopters of a formal set of Corporate Governance Guidelines, which have been modified over the years in response to evolving governance best practices and stockholder expectations. To maintain effective guidelines, the Corporate Governance Committee annually reviews the Company's governance practices, taking into consideration discussions with stockholders as part of our investor outreach and engagement program, industry surveys, and benchmarking studies, as well as governance guidelines published by institutional investors and proxy advisors.

Key governance practices adopted by the Board include:

GOVERNANCE PRINCIPLES	WEC ENERGY GROUP PRACTICES
Board composition	✓ • Annual election of directors since 2005 • 10 of 13 independent directors (based on director nominees) • Diverse representation of skills and competencies • Regular Board refreshment and mix of tenure • Comprehensive, ongoing Board succession planning process • Expectation that directors will dedicate sufficient time to perform duties
Board leadership	✓ • Separate CEO/Chair roles • Presiding independent director with defined duties • Chairman active in stockholder engagement and communications
Board governance practices	✓ • Expectation that directors participate in annual meeting with stockholders • Annual performance evaluations of CEO, Board, and Board committees • 100% independent Board Committees (except for the Executive Committee) • Board participation in critical activities, including agenda setting and strategic planning • Complete access to management and outside advisors for Board members • Stock ownership requirements • Regular executive sessions of independent directors at Board and committee meetings
Stockholder voting rights	✓ • Stockholders' ability to nominate directors; proxy access bylaw adopted in 2016 • One-share, one-vote standard; dual class voting is not practiced • Special meeting provisions
Executive compensation	✓ • Competitively tailored to business and industry, aligned with long-term performance and business strategy • Utilizes short- and long-term metrics, cash, and equity components; substantial portion is at risk • Public disclosure of peer groups, benchmarks, and performance measurements • Clawback policies for cash and equity; prohibition of hedging and pledging of Company securities • Stock ownership requirements

Business Conduct and Ethics

WEC Energy Group's Code of Business Conduct, which was benchmarked and updated in 2017 to comport with best practices, addresses, among other things: conflicts of interest; confidentiality; fair dealing; protection and proper use of Company assets; and compliance with laws, rules, and regulations (including insider trading laws). All WEC Energy Group directors, executive officers, and employees, including the principal executive, financial, and accounting officers, have a responsibility to comply with WEC Energy Group's Code of Business Conduct, to seek advice in doubtful situations, and to report suspected violations. The Company has not provided any waiver to the Code for any director, executive officer, or other employee.

The Company has several ways individuals can raise questions concerning WEC Energy Group's Code of Business Conduct and other Company policies. As one reporting mechanism, the Company has contracted with an independent service so that individuals can confidentially and anonymously report suspected violations of the Code of Business Conduct or other concerns, including those regarding accounting, internal accounting controls, or auditing matters.

Related Party Transactions/Conflicts of Interest

The Code of Business Conduct addresses, among other things, what actions are required when potential conflicts of interest may arise, including those from related-party transactions. Specifically, executive officers and members of the Board must obtain approval of the Audit and Oversight Committee Chair before: (1) obtaining any financial interest in or participating in any business relationship with any company, individual, or concern doing business with WEC Energy Group or any of its subsidiaries

that might influence the individual's decisions or job performance; (2) participating in any joint venture, partnership, or other business relationship with WEC Energy Group or any of its subsidiaries; and (3) serving as an officer or member of the board of any substantial, outside for-profit organization. Furthermore, before serving as an officer or member of the board of any substantial, outside for-profit organization, the CEO must obtain the approval of the full Board; members of the WEC Energy Group Board must obtain the prior approval of the Corporate Governance Committee. In addition, executive officers must obtain the prior approval of the CEO before accepting a position with a substantial non-profit organization; members of the Board must notify the Compliance Officer when joining the board of a substantial non-profit organization, but do not need to obtain prior approval.

WEC Energy Group's Code of Business Conduct also requires employees and directors to notify the Compliance Officer of situations where family members are a supplier or significant customer of WEC Energy Group or employed by one. To the extent the Compliance Officer deems it appropriate, he will consult with the Audit and Oversight Committee Chair in situations involving executive officers and members of the Board.

BOARD LEADERSHIP

Leadership Structure

Consistent with WEC Energy Group's bylaws and our Corporate Governance Guidelines, the Board retains the right to exercise its discretion in combining or separating the offices of Chief Executive Officer and Chairman of the Board. From May 1, 2016 to October 12, 2017, the office of the CEO was separated from the office of Chairman of the Board. Gale Klappa served as Non-Executive Chairman and Allen Leverett served as CEO. On October 12, 2017, the Board appointed Gale Klappa to serve as CEO during Mr. Leverett's medical leave. Mr. Klappa served as Chairman and CEO until February 1, 2019, when the Board appointed J. Kevin Fletcher as CEO and named Mr. Klappa as Executive Chairman of the Board, thus again separating the CEO and Chair positions.

Independent Presiding Director

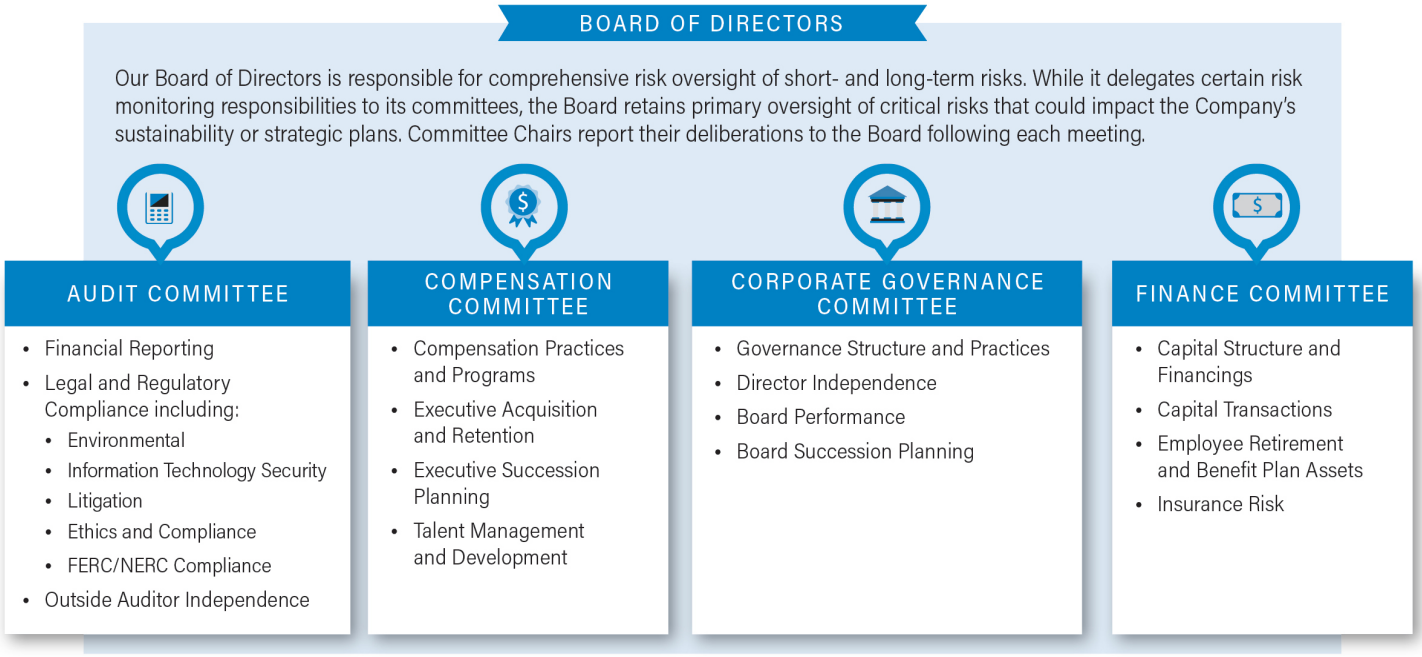
Our Corporate Governance Guidelines detail the specific duties to be performed by the Board's Independent Presiding Director, a position that is currently held by Director Bowles, Chair of the Corporate Governance Committee. Duties of this role include:

- presides at all meetings of the Board at which the Chairman is not present, including executive sessions of the non-management directors;
- serves as liaison between the CEO and the independent directors under most circumstances, although each individual director has full access to the CEO;
- has authority to call meetings of the independent directors;
- reviews and provides input to meeting agendas for the Board and its Committees;
- reviews meeting schedules to assure there is sufficient time for discussion of all agenda items;
- reviews all proposed changes to committee charters; and
- leads the annual Board evaluation.

RISK OVERSIGHT

The Board has overall responsibility for risk oversight and oversees the Company's risk environment and associated management practices as part of its evaluation of the Company's ongoing operations and strategic direction. During meetings of the Board and its committees, directors receive regular briefings from management on specific areas of risk, as well as emerging risks to the enterprise.

While it has retained oversight of certain broad risks that could impact the Company's long-term strategy, including, for example, climate change risk, the Board has delegated certain risk monitoring responsibilities to its committees. With the exception of the Executive Committee, each of the Board's committees regularly reports to the full Board on risks that fall within designated areas of responsibility, as described in each committee's respective charter. Examples of risk monitoring activity that have been designated to committees is shown in the chart below. More information on the committees' duties and responsibilities begins on page P-27.



Executive sessions for the non-management directors are generally held at every regularly scheduled committee meeting, during which committees have direct access to, and meet as needed with, Company representatives without other management present to discuss matters related to, among other things, risk management. Outside of scheduled meetings, the Board, its committees, and individual Board members have full access to senior executives and other key employees, including the CEO, CFO, General Counsel, Chief Audit Officer, Compliance Officer, Chief Information Officer, and Controller.

The Company has an Enterprise Risk Steering Committee, comprised of senior-level management employees whose purpose is to foster an enterprise-wide approach to identifying and managing risk. The Audit Services department conducts a semiannual enterprise risk assessment, and as part of this process, business leaders identify existing, new, or emerging issues or changes within their business areas that could have enterprise implications. Senior management is tasked with ensuring that these risks and opportunities are appropriately addressed. The results of these risk management efforts are reported to the executive leadership team and are the subject of regular reports to the Board.

The Board believes that its leadership structure and enterprise risk management program support the risk oversight function of the Board.

ENVIRONMENTAL AND SOCIAL GOVERNANCE

The Board is vigilant in its oversight of management's strategic decision-making as it navigates important developments in our industry, including new technologies, customer preferences, commodity prices, energy resiliency efforts, and ESG initiatives. Examples of how the Company's ESG practices are aligned with the needs of our stakeholders and support the well-being of the areas we serve are provided here.

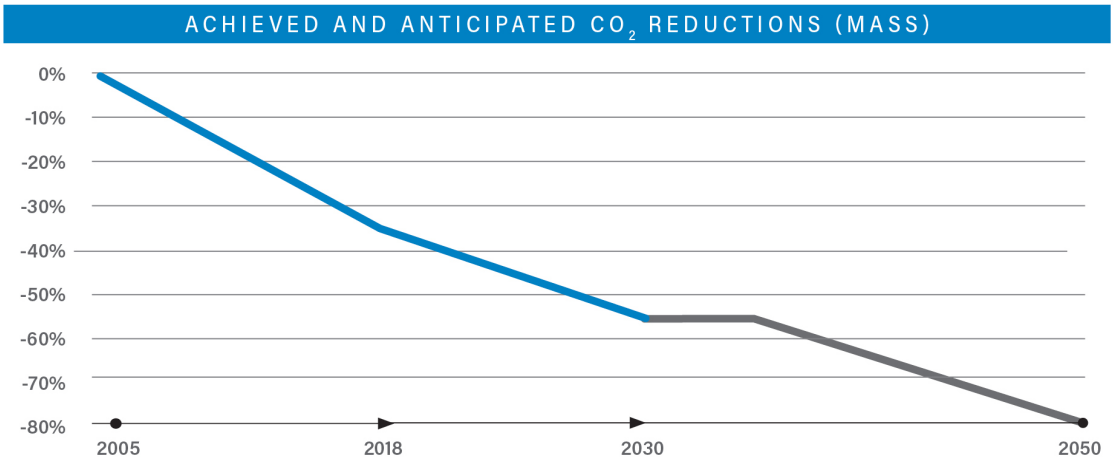
Environmental Stewardship

Protecting the environment is a responsibility we take seriously. Since 2000, the Company has invested in repowered generating facilities, renewable energy projects, state-of-the-art air quality control systems, power grid upgrades, and additional environmental protection technologies that position our electric generating companies well for the future.

We are working with our industry partners, environmental groups, and the State of Wisconsin to reduce carbon dioxide emissions, and we have set a two-part goal:

- 40 percent reduction below 2005 levels by 2030
- 80 percent reduction below 2005 levels by 2050

We are collaborating with Electric Power Research Institute and other industry members on the analysis of potential pathways beyond 2030 for electric companies, taking into account International Energy Agency's 2-degree scenario and other publicly available data.



Reduction goals:

40%
below 2005 levels
by 2030.

80%
below 2005 levels
by 2050.

Social Performance

Our employees are the bedrock of our business, driving key corporate initiatives focused on safety, diversity and inclusion, and talent development.

- Since 2008, the total number of OSHA-recordable and lost-time incidents have been reduced by 59 and 51 percent, respectively.
- Forbes included WEC Energy Group in its 2019 ranking of 'Best Employers for Diversity' and in its 2017 ranking of 'America's Best Employers.'
- We conducted a Company-wide, confidential employee engagement survey in 2018 to gauge employees' perceptions of their work, their leadership and the Company as a whole; leadership is using the results to actively address areas where the need for improvement was identified.

We are also deeply committed to our customers, suppliers, and communities.

- Again in 2018, WEC was recognized by Corporate Responsibility Magazine as one of the 100 best corporate citizens in America.
- In 2018, We Energies was named the most reliable utility in the Midwest for the eighth consecutive year by PA Consulting Group.
- Our companies spent more than $263.1 million in 2018 with certified minority-, women-, veteran- or service disabled-owned businesses, a nearly 50 percent increase over 2016.

Commitment to Reporting Transparency

In addition to engaging directly with stakeholders on environmental and social issues, we are committed to enhancing our transparency on these matters through a variety of reporting mechanisms, including:

- In 2019, the Company will issue its 18th annual Corporate Responsibility Report, covering our ESG performance in 2018.
- In 2019, the Company will issue its first report focused on climate change.
- For more than a decade, the Company has disclosed information regarding operations and ESG goals, risks and opportunities to CDP; the 2018 survey responses on climate and water can be found on the Company's website.
- The Company contributed to Edison Electric Institute's development of a template designed to make ESG metrics and information more accessible to investors and comparable across the electric sector.
- See the Corporate Responsibility section of our website for more details: www.wecenergygroup.com/csr

BOARD AND COMMITTEE PRACTICES

Board Meetings and Executive Sessions

During 2018, the Board met nine times and executed one written unanimous consent. All directors attended more than 75% of the total number of meetings of the Board and Board committees on which he or she served with the exception of Mr. Leverett who was excused for medical reasons. Mr. Leverett has consistently attended Board meetings since his return. Generally, all directors are expected to attend the Company's Annual Meetings of Stockholders. With the exception of Messrs. Bergstrom and Leverett, all directors attended the Annual Meeting of Stockholders held on May 3, 2018.

At every regularly scheduled Board and committee meeting, executive sessions are scheduled, and are generally held, for the non-management directors to meet without management present.

Director Orientation and Continuing Education

Management takes very seriously its responsibility to onboard new directors and continuously educate existing directors on the unique and complex issues inherent in operating a public company in the regulated utility industry.

Management has created a robust orientation program that introduces new directors to the Company's organizational structure, businesses, strategies, risks and opportunities, which assists new directors in developing company and industry knowledge to optimize their service on the Board. Directors Cunningham and Farrow engaged in a substantive orientation program throughout 2018, which included both in-house and field programming.

Opportunities to participate in regular continuing education are provided to the directors in the form of internally developed materials and presentations, programs presented by third parties, and financial support to attend qualifying academic or other independent programs, which help our directors enhance the skills and knowledge needed to carry out their responsibilities. During 2018, management facilitated numerous educational programs in which both Company and third-party experts presented to and discussed with the directors a variety of strategic and industry-related topics.

Succession Planning

Board Succession Planning

The Board is regularly engaged in rigorous discussions on Board succession planning, taking into consideration matters such as: current inventory of director skills; diversity, including gender, ethnicity, retirement age, and tenure; and future competencies needed to support appropriate oversight of the Company's strategic initiatives, financial and operational performance, and enterprise risks. During 2018, these discussions took into consideration the impact of Directors Bergstrom and Brodsky completing their service on the Board in May 2019, as well as the fact that multiple other directors will reach retirement age over the next two years. The election of Directors Cunningham and Farrow in 2018, and the election of Director Fletcher in February 2019, added skills and perspectives to the Board in areas it had determined were essential for carrying out its oversight responsibilities.

Management Succession Planning

The Compensation Committee, which has responsibility for reviewing organizational changes that have a significant impact on the Company, as well as reviewing succession plans for executive officers, held numerous discussions throughout 2018 to ensure continuity with respect to a number of organizational matters that occurred. The Committee also reviewed the Company's recruiting and development programs, which included updates on key talent, as well as workforce demographics across the organization.

Throughout 2018, the Board was also actively engaged in oversight of the executive succession planning process. The Board spent considerable time discussing the progress of Mr. Leverett's recovery with respect to his potential return to his executive duties. It also devoted significant time to evaluating alternatives in the event that Mr. Leverett did not return in an executive capacity.

In October 2018, Mr. Leverett resigned from his duties as President of WEC Energy Group, while retaining his position as a Board director. The Board approved of management's plan for a series of internal promotions, including appointing Mr. Fletcher as President, and associated reorganization activities in response to Mr. Leverett's resignation. Effective February 1, 2019, the Board appointed Mr. Fletcher as CEO of WEC Energy Group to succeed Mr. Klappa, who was appointed Executive Chairman.

The Board also approved the creation of the Office of the Chair comprised of four industry veterans: Gale Klappa, J. Kevin Fletcher, Scott Lauber, and Frederick Kuester. The Board believes this structure is appropriate to continue the smooth transition in leadership following Mr. Leverett's resignation as an active employee. This structure solidifies a strong and seasoned leadership team with the experience and skills needed to establish and carry out the Company's strategies, and provides the Company with strong and balanced executive leadership.

Annual Performance Evaluations

CEO Performance

The Compensation Committee, on behalf of the Board, annually evaluates the performance of the CEO and reports the results to the Board. The CEO is evaluated in a number of areas including leadership, vision, financial stewardship, strategy development and execution, management development, effective communication with constituencies, demonstrated integrity, and effective representation of the Company in community and industry affairs.

As part of this practice, the Compensation Committee obtains from each non-management director his or her input on the CEO's performance, which is summarized and then discussed in executive session with all non-management directors. The Chair of the Compensation Committee shares the evaluation results with the CEO. This procedure allows the Board to evaluate the CEO and to communicate the Board's expectations. The process is also used by the Compensation Committee to determine appropriate compensation for the CEO. This process was completed for Mr. Klappa in December 2018.

Board Performance

The Board annually evaluates its own performance, a process that is led by the Independent Presiding Director. The Board uses a framework of questions developed by the National Association of Corporate Directors to conduct the performance evaluation. Each director independently considers several "reflection" questions, in addition to a list of questions that fall within five broad categories: board composition and leadership; board committees; board meetings; overall effectiveness of the Board; and overall effectiveness of the Board with regard to management.

The Independent Presiding Director uses this framework to provide each Board member an opportunity to speak candidly during one-on-one discussion sessions. At the conclusion of the individual feedback sessions, the Independent Presiding Director leads the Corporate Governance Committee and the Board through a group discussion of key takeaways. This evaluation process was conducted in November and December of 2018, following which the Corporate Governance Committee and the Board discussed the findings at their meetings in January 2019. It is routine practice for the Board to incorporate recommendations from its evaluation process into new standard practices, and the Corporate Governance Committee routinely uses the results of this process to foster continuous improvement of the Board's governance activities.

Committee Performance

Each committee, except the Executive Committee, conducts an annual performance evaluation of its own activities and reports the results to the Board. During this evaluation, each committee compares its performance against the requirements of its charter and its annual planning calendar; contemplates a series of questions related to the qualifications and performance of committee members; considers the quality and quantity of information provided to the committee in advance of its meetings; and evaluates the effectiveness of the processes the committee uses to carry out its oversight responsibilities. The results of the annual evaluations are used by each committee to identify its strengths and areas where its governance practices can be improved. Each committee may recommend changes to its charter to the full Board based upon the evaluation results.

BOARD COMMITTEES

The Board of Directors has the following committees: Audit and Oversight, Compensation, Corporate Governance, Finance, and Executive. Each committee, except the Executive Committee, operates under a charter approved by the Board, which can be found on our website at www.wecenergygroup.com/govern/committee-comp.htm. With the exception of the Executive Committee, only independent directors serve on the standing committees.

Directors John Bergstrom and William Brodsky will complete their service as directors in 2019 and thus are not serving as nominees for re-election at the 2019 Annual Meeting. Mr. Brodsky currently serves as a member of the Finance Committee. Mr. Bergstrom currently chairs the Compensation Committee and is a member of the Audit and Oversight Committee.The Board is finalizing its plan for appointing a new Compensation Committee Chair.

Audit and Oversight

Members	Key Responsibilities
Thomas J. Fischer, Chair John F. Bergstrom Barbara L. Bowles Patricia W. Chadwick Danny L. Cunningham Henry W. Knueppel **2018 Meetings: 6**	• Oversee the integrity of the financial statements. • Oversee management compliance with legal and regulatory requirements. • Review the Company's environmental and compliance programs. • Review, approve, and evaluate the independent auditors' services. • Oversee the performance of the internal audit function and independent auditors. • Discuss risk management and major risk exposures and steps taken to monitor and control such exposures. • Establish procedures for the submission and treatment of complaints and concerns regarding the Company's accounting controls and auditing matters. • Prepare the audit committee report required by the SEC for inclusion in the proxy statement.

The Audit and Oversight Committee is a separately designated committee established in accordance with Section 3(a)(58)(A) of the Securities Exchange Act of 1934, as amended. The Audit and Oversight Committee consists solely of independent directors who meet the independence requirements of the SEC, NYSE and the Board's Corporate Governance Guidelines. In addition, the Board has determined that all of the members of the Audit and Oversight Committee are financially literate as required by NYSE rules and qualify as audit committee financial experts within the meaning of SEC rules.

Compensation

Members	Key Responsibilities
John F. Bergstrom, Chair Thomas J. Fischer Ulice Payne, Jr. **2018 Meetings: 6**	• Determine and annually review the Compensation Committee's compensation philosophy. • Oversee the development of competitive, performance-based executive and director compensation programs. • Review and approve the compensation paid to select employees, including certain senior officers and executive officers (including base salaries, incentive compensation, and benefits). • Establish and administer the CEO compensation package. • Set performance goals relevant to the CEO's compensation. • Annually evaluate CEO performance and determine compensation adjustments. • Oversee succession planning and assignments to key executive officers. • Prepare the report required by the SEC for inclusion in the proxy statement. • Review the results of the most recent stockholder advisory vote on compensation of the NEOs.

The Compensation Committee consists solely of independent directors who meet the independence requirements of the SEC, NYSE and the Board's Corporate Governance Guidelines.

The Compensation Committee is also charged with administering the compensation package of WEC Energy Group's non-management directors. The Compensation Committee meets with the Corporate Governance Committee annually to review the compensation package of WEC Energy Group's non-management directors and to determine the appropriate amount of such compensation.

The Compensation Committee, which has authority to retain advisers, including compensation consultants, at WEC Energy Group's expense, retained Frederic W. Cook & Co., Inc. ("FW Cook") to analyze and help develop the Company's executive compensation program, and to assess whether the compensation program is competitive and supports the Committee's objectives. FW Cook also assesses and provides recommendations on non-management director compensation, as discussed in more detail on page P-32. FW Cook is engaged solely by the Compensation Committee to provide executive compensation consulting services, and does not provide any additional services to the Company.

In connection with its retention of FW Cook, the Compensation Committee reviewed FW Cook's independence including: (1) the amount of fees received by FW Cook from WEC Energy Group as a percentage of FW Cook's total revenue; (2) FW Cook's policies and procedures designed to prevent conflicts of interest; and (3) the existence of any business or personal relationships that could impact independence. After reviewing these and other factors, the Compensation Committee determined that FW Cook is independent and the engagement did not present any conflicts of interest. FW Cook also determined that it was independent from the Company's management, which was confirmed in a written statement delivered to the Compensation Committee.

For more information regarding our executive and director compensation processes and procedures, please refer to "Compensation Discussion and Analysis" beginning on page P-35 and to "Director Compensation" beginning on page P-32, respectively.

Corporate Governance

Members	Key Responsibilities
Barbara L. Bowles, Chair Albert J. Budney, Jr. Curt S. Culver Henry W. Knueppel **2018 Meetings: 3**	• Establish and annually review the Corporate Governance Guidelines to verify that the Board is effectively performing its fiduciary responsibilities to stockholders. • Establish and annually review director candidate selection criteria. • Identify and recommend candidates to be named as nominees of the Board for election as directors. • Lead the Board in its annual review of the Board's performance.

The Corporate Governance Committee consists solely of independent directors who meet the independence requirements of the NYSE and the Board's Corporate Governance Guidelines.

Finance

Members	Key Responsibilities
Curt S. Culver, Chair William J. Brodsky Patrica W. Chadwick William M. Farrow III Ulice Payne, Jr. Mary Ellen Stanek	• Review and monitor the Company's current and long-range financial policies and strategies, including our capital structure and dividend policy. • Authorize the issuance of corporate debt within limits set by the Board. • Discuss policies and financial programs with respect to financial risk management. • Approve the Company's financial plan, including the capital budget.

2018 Meetings: 4

The Finance Committee consists solely of independent directors who meet the independence requirements of the NYSE and the Board's Corporate Governance Guidelines.

Executive

The Board also has an Executive Committee, which may exercise all powers vested in the Board except action regarding dividends or other distributions to stockholders, filling Board vacancies, and other powers which by law may not be delegated to a committee or actions reserved for a committee comprised of independent directors. The members of the Executive Committee are Gale E. Klappa (Chair), John F. Bergstrom, Barbara L. Bowles, Thomas J. Fischer, and Ulice Payne, Jr. The Executive Committee did not meet in 2018.

WHERE TO FIND MORE INFORMATION ON GOVERNANCE

You can find our Corporate Governance Guidelines, Code of Business Conduct, and other corporate governance materials, including WEC Energy Group's Restated Articles of Incorporation, Bylaws, Board committee charters and Board contact information, on the Corporate Governance section of our website at www.wecenergygroup.com/govern/governance.htm. You can request copies of these materials from the Corporate Secretary at the address provided below under "Communicating with the Board."

COMMUNICATING WITH THE BOARD

Correspondence may be sent to the directors, including the non-management directors, in care of the Corporate Secretary, Margaret C. Kelsey, at the Company's principal business office, 231 W. Michigan Street, PO Box 1331, Milwaukee, Wisconsin 53201. All communications received as set forth above will be opened by the Corporate Secretary for the sole purpose of confirming the contents represent a message to the Company's directors. Pursuant to instructions from the Board of Directors, all communication, other than advertising, promotion of a product or service, or patently offensive material, will be forwarded promptly to the addressee.

DIRECTOR COMPENSATION

Consistent with its charter, the Compensation Committee seeks to maintain a competitive director compensation program that enables the Company to attract and retain key individuals and to motivate them to help the Company achieve its short- and long-term goals. As such, the committee is responsible for reviewing key market-based trends in director compensation and benefits packages and for recommending changes to the Board, as appropriate, that will attract and retain quality directors. The Committee's charter authorizes it to engage consultants or advisors in connection with its review and analysis of director compensation. The Compensation Committee used FW Cook during 2018 for this purpose. Directors who are also employees of the Company do not receive additional compensation for service as a director.

2018 Compensation of the Board of Directors

The following table describes the components of the non-management director compensation program during 2018. The Compensation Committee believes that this program:

- is equitable based upon the work required of directors serving an entity of the Company's size and scope, and
- ties the majority of director compensation to stockholder interests because the value of the equity awards fluctuates depending upon the Company's stock price.

Compensation Element	2018 Non-Management Director Compensation Program
Annual Cash Retainer	$100,000, which may be deferred at the director's option
Annual Equity Retainer	$135,000 in restricted stock, which vests one year from grant date
Annual Committee Chair Fees	
• Audit and Oversight	$20,000 paid in $5,000 quarterly increments
• Compensation	$15,000 paid in $3,750 quarterly increments
• Corporate Governance	$15,000 paid in $3,750 quarterly increments
• Finance	$15,000 paid in $3,750 quarterly increments
Board and Committee Meeting Fees	None
Stock Ownership Guideline	Ownership of common stock or deferred stock units that have a value equal to five times the annual cash retainer for non-management directors to be satisfied within five years of joining the Board

Insurance is also provided by the Company for director liability coverage, fiduciary and employee benefit liability coverage, and travel accident coverage for director travel on Company business. The premiums paid for this insurance are not included in the amounts reported in the table below.

The Company reimburses directors for all out-of-pocket travel expenses. These reimbursed amounts are not reflected in the table below.

Deferred Compensation Plan. Non-management directors may defer all or a portion of their cash fees pursuant to the Directors' Deferred Compensation Plan. Directors have two investment options in the plan - the Company's phantom stock measurement fund or a prime rate fund. The value of the phantom stock measurement fund appreciates or depreciates based upon market performance of the Company's common stock, and it also grows through the accumulation of reinvested dividend equivalents. Deferral amounts are credited in the name of each participating director to accounts on the books of WEC Energy Group that are unsecured and are payable only in cash at the time elected by the director. Deferred amounts will be paid out of general corporate assets or the assets of the Wisconsin Energy Corporation 2014 Rabbi Trust discussed later in this proxy statement.

Legacy Charitable Awards Program. Directors elected prior to January 1, 2007 participate in a Directors' Charitable Awards Program under which the Company intends to contribute up to $100,000 per year for 10 years to one or more charitable organizations chosen by each participating director, including employee directors, following the director's death. Charitable donations under the program will be paid out of general corporate assets. Directors derive no financial benefit from the program, and all income tax deductions accrue solely to the Company. The tax deductibility of these charitable donations may mitigate the net cost to the Company. The Directors' Charitable Awards Program has been eliminated for any new directors elected after January 1, 2007. Directors already participating as of that date are Messrs. Bergstrom, Culver, Fischer, Klappa, and Payne, and Mmes. Bowles and Chadwick.

Director Compensation Table. The following table summarizes the total compensation received by each of WEC Energy Group's non-management directors during 2018.

Name	Fees Earned or Paid In Cash ($)	(1) Stock Awards ($)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)	Total ($)
John F. Bergstrom	115,000	135,000	—	—	—	21,947	271,947
Barbara L. Bowles	115,000	135,000	—	—	—	20,608	270,608
William J. Brodsky	100,000	135,000	—	—	—	—	235,000
Albert J. Budney, Jr.	100,000	135,000	—	—	—	—	235,000
Patricia W. Chadwick	100,000	135,000	—	—	—	30,110	265,110
Curt S. Culver	115,000	135,000	—	—	—	21,689	271,689
Danny L. Cunningham	100,000	135,000	—	—	—	—	235,000
William M. Farrow III	100,000	135,000	—	—	—	—	235,000
Thomas J. Fischer	120,000	135,000	—	—	—	21,947	276,947
Henry W. Knueppel	100,000	135,000	—	—	—	—	235,000
Allen L. Leverett (2)	—	—	—	—	—	—	—
Ulice Payne, Jr.	100,000	135,000	—	—	—	15,901	250,901
Mary Ellen Stanek	100,000	135,000	—	—	—	—	235,000

(1) Other than Mr. Cunningham (2,175 shares), Mr. Farrow (2,114 shares), and Mr. Leverett (23,248 shares), each director listed in this table held 4,828 shares of restricted stock as of the close of business on December 31, 2018.

(2) Effective October 10, 2018, Mr. Leverett resigned his position as President of WEC Energy Group but continues to serve as a member of the Board. Mr. Leverett did not receive any non-management director compensation during 2018. All compensation that Mr. Leverett received during 2018 for serving as an executive officer is reported in the "Summary Compensation Table" on page P-52.

Fees Earned or Paid in Cash. The amounts reported in the Fees Earned or Paid in Cash column include annual cash-based retainers for each non-management director and applicable annual committee chair fees earned during 2018 regardless of whether such retainers and fees were paid in cash or deferred.

Stock Awards. On January 2, 2018, each non-management director (other than Mr. Leverett) received his or her 2018 annual equity retainer in the form of restricted stock equal to a value of $135,000. The amounts reported in the Stock Awards column reflect the aggregate grant date fair value, as computed in accordance with Financial Accounting Standards Board Accounting Standards Codification ("FASB ASC") Topic 718, excluding estimated forfeitures, of the restricted stock awarded. Each reported restricted stock award vests in full one year from the grant date.

All Other Compensation. All amounts reported in the All Other Compensation column represent costs for the Directors' Charitable Awards Program. See "Legacy Charitable Awards Program" above for additional information.

2019 Compensation of the Board of Directors

In December 2018, the Compensation Committee completed its annual review of director compensation and determined that, based upon research provided by FW Cook, total non-management director compensation was consistent with the market median. As a result, the Compensation Committee concluded and the Board agreed that it was appropriate for 2019 Board compensation to remain unchanged from the approved 2018 levels.

PROPOSAL 2: ADVISORY VOTE TO APPROVE COMPENSATION OF THE NAMED EXECUTIVE OFFICERS

Pursuant to Section 14A of the Securities Exchange Act of 1934, the Company seeks your advisory vote on the approval of the compensation paid to our named executed officers (commonly referred to as "Say-on-Pay") as described in the Compensation Discussion and Analysis and the related tables included in this proxy statement. Approval, on a non-binding, advisory basis, of the compensation of the named executed officers requires the affirmative vote of a majority of the votes cast in person or by proxy at the Meeting. Presuming a quorum is present, shares not voted, whether by broker non-vote, abstention, or otherwise, have no effect on the outcome of this matter. Because your vote is advisory, it will not be binding on the Board or the Company. However, the Compensation Committee will review the voting results and take them into consideration when making future decisions regarding executive compensation.

As described in the Compensation Discussion and Analysis on pages P-35 through P-51 of this proxy statement, the Compensation Committee has structured the Company's executive compensation program with the following objectives in mind:

- offer a competitive, performance-based plan;
- enable the Company to attract and retain key individuals;
- reward achievement of the Company's short-term and long-term goals; and
- align with the interest of the Company's stockholders and customers.

As described in this proxy statement, the Company believes that the compensation paid to our named executed officers in 2018 was well-tailored to achieve these objectives, tying a significant portion of total pay to performance and aligning the interests of the named executed officers with those of stockholders and customers. We encourage you to carefully review the Compensation Discussion and Analysis and related tables included in this proxy statement, which describe in greater detail WEC Energy Group's compensation philosophy and programs, as well as the 2018 compensation levels, in connection with approval of the following resolution:

> "RESOLVED, that the stockholders approve, on an advisory basis, the compensation paid to the Company's named executive officers as disclosed in the Proxy Statement for the 2019 Annual Meeting."

The Board of Directors recommends that you vote "FOR" the advisory vote on Executive Compensation.

COMPENSATION DISCUSSION AND ANALYSIS

The following discussion provides an overview and analysis of our executive compensation program, including the role of the Compensation Committee of our Board, the elements of our executive compensation program, the purposes and objectives of these elements, and the manner in which we established the compensation of our named executive officers ("NEOs") for fiscal year 2018.

References to “we,” “us,” “our,” "Company," and “WEC Energy Group” in this discussion and analysis mean WEC Energy Group, Inc. and its management, as applicable.

EXECUTIVE SUMMARY

Overview

The primary objective of our executive compensation program is to provide a competitive, performance-based plan that enables the Company to attract and retain key individuals and to reward them for achieving both the Company’s short-term and long-term goals without creating an incentive for our NEOs to take excessive risks. Our program has been designed to provide a level of compensation that is strongly dependent upon the achievement of short-term and long-term goals that are aligned with the interests of our stockholders and customers. To that end, a substantial portion of pay is at risk, and generally, the value will only be realized upon strong corporate performance.

2018 Business Highlights

During 2018, we continued to make excellent progress in our efforts to integrate employees, merge and improve business processes, and consolidate IT infrastructure following our acquisition of Integrys Energy Group in June 2015. At the same time, the Company achieved solid results and continued to create long-term value for our stockholders and customers by focusing on the following:

- World-class reliability
- Operating efficiency
- Employee safety
- Financial discipline
- Exceptional customer care

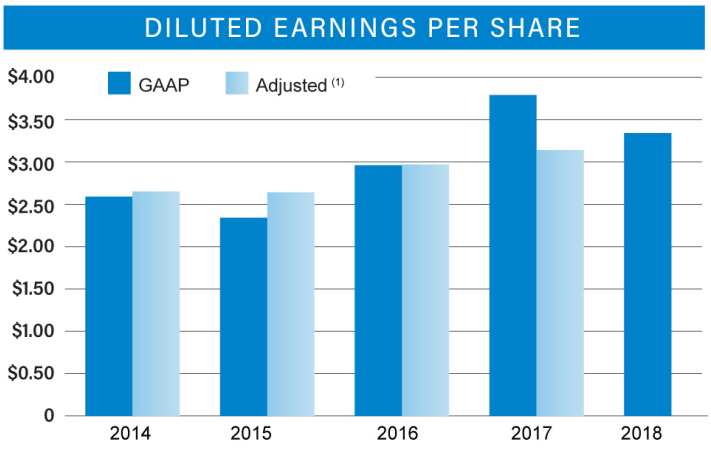
In addition, the seamless continuity in leadership provided by our senior executive management team following Allen Leverett’s unexpected illness in October 2017 resulted in solid earnings and cash flow generation for the Company in 2018.

Commitment to Stockholder Value Creation. Financially, WEC Energy Group again delivered solid earnings growth, generated strong cash flow, and increased the dividend for the 15th consecutive year. In January 2018, the Board raised the quarterly dividend 6.25% to $0.5525 per share, equivalent to an annual rate of $2.21 per share. In January 2019, the Board increased the quarterly dividend 6.8% to $0.59 per share, which is equivalent to an annual rate of $2.36 per share, in line with our plan to maintain a dividend payout ratio of 65% to 70% of earnings. Overall, the Company also turned in strong performances in customer satisfaction and network reliability during 2018.

Specific Company achievements during 2018 include:

2018 Financial Highlights

- WEC Energy Group delivered solid earnings growth again, generated strong cash flow, and increased the dividend for the 15th consecutive year.
- We achieved fully diluted earnings per share of $3.34. (2)
- Each of our regulated utility subsidiaries earned its allowed rate of return.
- We returned approximately $697.3 million to WEC Energy Group stockholders through dividends.
- Our common stock traded at a then all-time high of $75.48 on December 12, 2018.
- In January 2019, the Board raised the quarterly dividend to $0.59 per share, which is equivalent to an annual dividend rate of $2.36 per share.



(1) For 2017, excludes a one-time $0.65 per share gain related to a revaluation of our deferred taxes as a result of the Tax Cuts and Jobs Act of 2017. For 2016, 2015, and 2014, excludes costs of $0.01, $0.30, and $0.06 per share, respectively, related to our acquisition of Integrys. See Appendix A on P-79 for a full GAAP reconciliation and an explanation of why we believe the presentation of adjusted earnings per share is relevant and useful to investors.

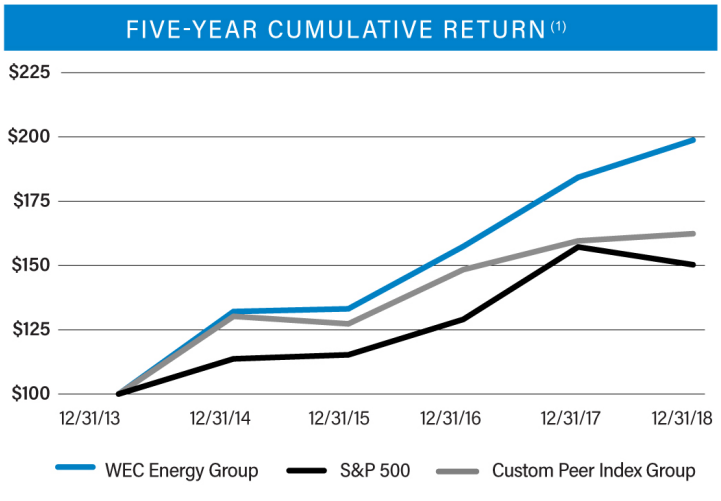
2018 Performance Highlights

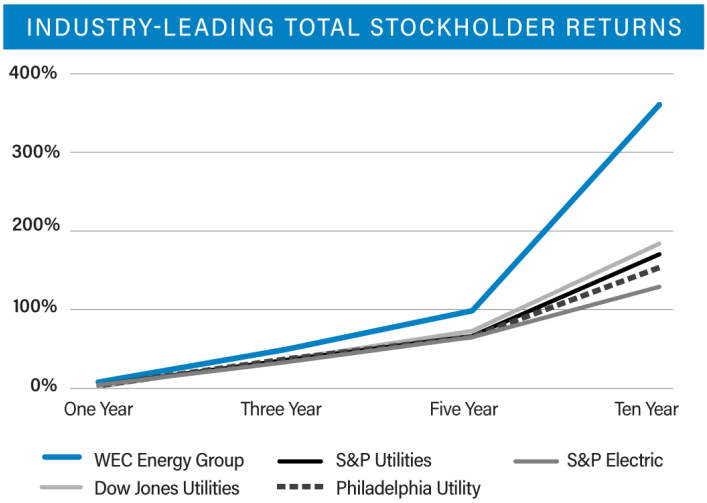
- WEC Energy Group was again recognized in 2018 by Corporate Responsibility Magazine as one of the 100 best corporate citizens in America.
- PA Consulting Group named We Energies the most reliable utility in the Midwest for the eighth year in a row.
- Set a new long-term goal to reduce carbon dioxide emissions below 2005 levels by 80% by 2050.
- Closed nearly 1,500 megawatts of older, less efficient coal-fired generation.
- Spent $263.1 million with qualified women-, minority-, and veteran- or service disabled- owned businesses, the highest spending with diverse suppliers in the Company's history.(2)
- Wisconsin Public Service Corporation ("WPSC") was named as a 2018 Most Trusted Utility Brand by Market Strategies International.
- All major utility subsidiaries either met or exceeded our overall customer satisfaction targets.(2)
- Continued to grow the Company's non-utility energy infrastructure segment, acquiring majority interests in three different wind farms with a total investment of approximately $587 million. Filed with the Public Service Commission of Wisconsin for approval for WPSC to partner with Madison Gas & Electric on two major solar projects in Wisconsin, where WPSC would own 100 megawatts of each project.

(2) This measure is a component of our short-term incentive compensation program.

Long-Term Stockholder Returns

Over the past decade, WEC Energy Group has consistently delivered among the best total returns in the industry and did so again in 2018.





(1) The Five-Year Cumulative Return Chart 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. For information about the Custom Peer Index Group, see "Performance Graph" in the Company's 2018 Annual Report.

Source: Bloomberg; assumes all dividends are reinvested and returns are compounded daily.

Consideration of 2018 Stockholder Advisory Vote and Stockholder Outreach

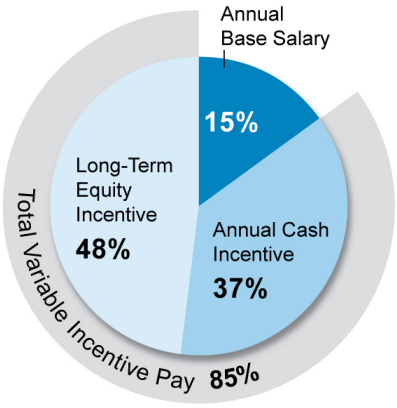
At the 2018 Annual Meeting of Stockholders, the Company's stockholders approved the compensation of our named executive officers with 94% of the votes cast. The Compensation Committee considered this outcome as well as the feedback received during meetings we again held with several of our institutional stockholders. During 2018, we held dedicated sessions with stockholders representing approximately 27.1% of the Company's outstanding common stock about our governance and compensation practices. The Compensation Committee is always looking for ways to refine our compensation program. However, in light of the significant stockholder support our executive compensation program received in 2018 and the payout levels under our performance-based program for 2018, the Compensation Committee believes that the current compensation program is competitive, aligned with our financial and operational performance, and in the best interests of the Company, stockholders, and customers.

COMPONENTS OF OUR EXECUTIVE COMPENSATION PROGRAM

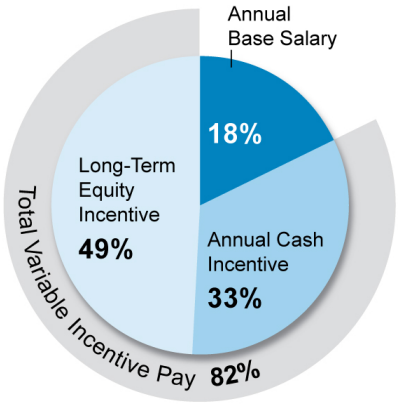
We have three primary elements of total direct compensation: (1) base salary; (2) annual incentive awards; and (3) long-term incentive awards consisting of a mix of performance units, stock options, and restricted stock. The Compensation Committee again retained Frederic W. Cook & Co., Inc. ("FW Cook") as its independent compensation consultant to advise the Compensation Committee with respect to our executive compensation program. The Compensation Committee generally relied on the recommendations of FW Cook as it developed the 2018 program.

As shown in the charts below, 85% of Mr. Klappa's 2018 total direct compensation and an average of 82% of the other NEOs' 2018 total direct compensation is tied to Company performance and is not guaranteed.

CEO 2018 TOTAL DIRECT COMPENSATION MIX



OTHER NEOs 2018 TOTAL DIRECT COMPENSATION MIX



In addition to the components of total direct compensation identified above, our retirement programs are another important component of our compensation program.

To the extent feasible, we believe it is important that the Company's compensation program not dilute the interests of current stockholders. Therefore, we currently use open-market purchases to satisfy our benefit plan obligations, including the exercise of stock options and vesting of restricted stock.

This Compensation Discussion and Analysis contains a more detailed discussion of each of the above components for 2018, including FW Cook's recommendations with respect to each component.

Compensation Governance and Practices

The Compensation Committee annually reviews and considers the Company's compensation policies and practices to ensure our executive compensation program aligns with our compensation philosophy. Highlighted below is an overview of our current compensation practices.

What We Do

- Our compensation program focuses on key Company results (financial, safety, customer satisfaction, diversity) that are aligned with our strategic goals.
- A substantial portion of compensation is at risk and tied to Company performance.
- The compensation program has a long-term orientation aligned with stockholder interests.
- The Compensation Committee retains an independent compensation consultant to help design the Company's compensation program and determine competitive levels of pay.
- The Compensation Committee's independent compensation consultant reviews competitive employment market data from two general industry surveys and a comparison group of companies similar to WEC Energy Group.
- We have implemented a clawback policy that provides for the recoupment of incentive-based compensation. (page P-49)
- Annual incentive-based compensation contains multiple, pre-established performance metrics aligned with stockholder and customer interests. (page P-42)
- The Performance Unit Plan award payouts (including dividend equivalents) are based on stockholder return as compared to an appropriate peer group and Additional Performance Measure(s), selected by the Compensation Committee. (page P-45)
- The Performance Unit Plan requires a separation from service following a change in control for award vesting to occur. (page P-48)
- Equity award and other benefit plan obligations are satisfied through open-market purchases of WEC Energy Group common stock.
- Meaningful stock ownership levels are required for senior executives. (page P-49)
- Ongoing engagement with investors takes place to ensure that compensation practices are responsive to stockholder interests.
- We prohibit hedging and pledging of WEC Energy Group common stock. (page P-49)
- We prohibit entry into any new arrangements that obligate the Company to pay directly or reimburse individual tax liability for benefits provided by the Company. (page P-50)
- We prohibit repricing of stock options without stockholder approval.

Competitive Benchmarking

As a general matter, we believe the labor market for WEC Energy Group executive officers is consistent with that of general industry. Although we recognize our business is focused on the energy services industry, our goal is to have an executive compensation program that will allow us to be competitive in recruiting the most qualified candidates to serve as executive officers of the Company, including individuals who may be employed outside of the energy services industry. Further, in order to retain top performing executive officers, we believe our compensation practices must be competitive with those of general industry.

To confirm that our annual executive compensation is competitive with the market, FW Cook reviewed the compensation data obtained from Willis Towers Watson's 2018 Executive Compensation Data Bank as well as similar data from Aon Hewitt. FW Cook also analyzed the compensation data from a peer group of 18 companies similar to WEC Energy Group in size and business model. The methodology used by FW Cook to determine the peer group of companies is described below.

FW Cook started with U.S. companies in the Standard & Poor's database, and then limited those companies to the same line of business as WEC Energy Group as indicated by the Global Industry Classification Standards. This list of companies was then further limited to companies with revenues between $2.5 billion and $22.8 billion (approximately one-third to three times the size of WEC Energy Group's revenues), and that were within a reasonable size range in various other measures such as operating income, total assets, total employees, and market capitalization. From this list, FW Cook selected companies similar in overall size to WEC Energy Group with consideration given to companies that met one or more of the following criteria:

- Diversified, technically sophisticated utility operations (e.g., multiple utilities, electric utilities);
- Minimal non-regulated business; and/or
- Operates in the Midwest.

These criteria resulted in a comparison group of 18 companies with median revenues and market capitalization of approximately $9.6 billion and $17 billion, respectively.

The comparison group utilized for purposes of 2018 compensation includes the same companies as the previous year's comparison group, and was comprised of the 18 companies listed below.

- Alliant Energy Corporation
- Ameren Corporation
- American Electric Power Company
- CMS Energy Corporation
- CenterPoint Energy
- Consolidated Edison, Inc.
- DTE Energy Co.
- Edison International
- Entergy Inc.
- Eversource Energy
- FirstEnergy Corp.
- NiSource Inc.
- PG&E Corporation
- PPL Corp.
- Pinnacle West Capital Corp.
- SCANA Corporation
- The Southern Company
- Xcel Energy Inc.

The Compensation Committee approved this comparison group.

DETERMINATION OF MARKET MEDIAN

In order to determine the "market median" for our NEOs, FW Cook recommended that the survey data from Willis Towers Watson and Aon Hewitt receive a 75% weighting and the comparison group of 18 companies receive a 25% weighting. The Compensation Committee agreed with this recommendation. The survey data received a higher weighting because we consider the labor market for our executives to be consistent with that of general industry. Using this methodology, FW Cook recommended, and the Compensation Committee approved, the appropriate market median for each of our NEOs.

The comparison of each component of compensation with the appropriate market median when setting the compensation levels of our NEOs generally drives the allocation of cash versus non-cash compensation and short-term versus long-term incentive compensation.

DETERMINATION OF MESSRS. KLAPPA'S AND KUESTER'S 2018 COMPENSATION

As we previously reported, Mr. Klappa agreed to resume the role of CEO of WEC Energy Group after Mr. Leverett suffered a stroke in October 2017. In recognition of his continued service and leadership while Mr. Leverett continued to recover from his stroke, the Compensation Committee, in consultation with FW Cook regarding the appropriate pay level for Mr. Klappa under the circumstances, determined that the aggregate amount of Mr. Klappa's direct compensation (as opposed to each individual component of direct compensation) should be substantially the same as it was at the time of his retirement in 2016. Therefore, the Compensation Committee set Mr. Klappa's 2018 annual base salary at $1,425,000 and his annual incentive plan target at 120% of base salary, the same target he was receiving at the time of his retirement in 2016. The Committee then awarded Mr. Klappa long-term incentive compensation at a level that was lower than he was receiving in 2016, so that the total value of direct compensation Mr. Klappa received would be substantially equal to his 2016 compensation levels and at or near the 2018 median for overall compensation.

Mr. Kuester had an ongoing consulting relationship with the Company following his retirement in 2013 pursuant to which he periodically advised on WEC Energy Group's capital program. Due to Mr. Leverett's medical leave beginning in October 2017, and in order to provide for continuity and dedicated oversight of the Company's significant capital program during Mr. Leverett's absence, Mr. Kuester's consulting duties significantly increased at the end of 2017. This substantial increase in duties resulted in a significant increase in payments under his prior consulting agreement, which remained in effect until Mr. Kuester agreed to return to the Company and assume the position of Senior Executive Vice President effective March 1, 2018. The Compensation Committee determined that the aggregate amount of Mr. Kuester's direct compensation as Senior Executive Vice President should be substantially the same as it was at the time he retired as Executive Vice President from the Company in 2013, recognizing that he was assuming additional responsibilities from those he held prior to his retirement in 2013. As a result, the Committee set Mr. Kuester's 2018 annualized base salary and target award under the STPP at $765,000 and 80% of base salary, respectively. Mr. Kuester's long-term incentive compensation was set slightly below the level he was receiving when he retired in 2013. Mr. Kuester's responsibilities include oversight of the development and execution of the Company's capital plan.

MR. LEVERETT'S 2018 COMPENSATION

We compensated Mr. Leverett pursuant to the Company's standard medical leave policy until he resigned as President of WEC Energy Group effective October 10, 2018. At the time 2018 compensation levels were being determined, we did not know how long Mr. Leverett would be on medical leave, but fully expected that he would return to the role of Chief Executive Officer. As a result, the Compensation Committee evaluated Mr. Leverett's 2017 performance up to the start of his medical leave in October 2017, and determined that he had earned a standard cost-of-living base salary increase of 3% for 2018. In addition, Mr. Leverett's target award level under the STPP remained unchanged at 125% of base salary. In accordance with the Company's standard benefit plans and policies applicable to all management employees, Mr. Leverett received an award under the STPP pro-rated to his number of days of service in 2018 prior to his resignation as President. In addition, Mr. Leverett received a customary long-term incentive award in accordance with the Company's standard practices for those on medical leave. Upon his resignation as President, Mr. Leverett began receiving payments under other applicable benefit plans of the Company in which he was already a participant and under which he was eligible to receive payments.

ANNUAL BASE SALARY

The annual base salary component of our executive compensation program provides each executive officer with a fixed level of annual cash compensation. We believe that providing annual cash compensation through a base salary is an established market practice and is a necessary component of a competitive compensation program.

Based upon the market data analyzed by FW Cook, we generally target base salaries to be at or near the market median for each NEO. However, the Compensation Committee may, in its discretion, set base salaries at a different amount when the Compensation Committee deems it appropriate.

Actual salary determinations are made taking into consideration factors such as the relative levels of individual experience, performance, responsibility, and contribution to the results of the Company's operations. At the beginning of each year, our CEO develops a list of goals for WEC Energy Group and our employees to achieve during the upcoming year. At the end of the year, our CEO measures the performance of the Company against each stated goal and reports the results to the Board. The Compensation Committee then takes the Company's performance into consideration when establishing our CEO's compensation for the upcoming year. Our CEO undertakes a similar process with the NEOs, who develop individual goals related to the achievement of the Company's goals developed by our CEO. At the end of the year, each officer's performance is measured against these goals. Compensation recommendations and determinations for the upcoming year for each executive officer also take into consideration the level of such performance.

For information about Messrs. Klappa's, Kuester's and Leverett's base salary, see the discussion about each individual's compensation above.

With respect to the remaining NEOs, in December 2017, Mr. Klappa recommended an annual base salary to the Compensation Committee based upon a review of the market compensation data provided by FW Cook and the factors described above. The Compensation Committee approved the recommendations, which represented an average increase in annual base salary of approximately 3% for Messrs. Fletcher and Keyes, and Ms. Kelsey, and an increase in annual base salary of approximately 12% for Mr. Lauber.

In recognition of Mr. Fletcher's appointment to President of WEC Energy Group in October 2018, the Compensation Committee increased his annual base salary to $700,000.

Upon his appointment as Executive Vice President and Chief Financial Officer in April 2016, Mr. Lauber's base salary was initially set below market median because of how significant such an increase would have been in order to bring his salary at or near median. As we previously reported, the Compensation Committee's intent was to increase Mr. Lauber's salary in multiple steps to eventually move it to market median. In line with this intent, the Compensation Committee increased Mr. Lauber's base salary by 12% effective January 1, 2018, and again by 7.9% effective July 29, 2018, to provide an aggregate base salary of $600,000 in 2018, putting his salary at market median. The annual base salary of each NEO (other than Mr. Klappa, whose total direct compensation was determined as described above) was at or near the market median.

ANNUAL CASH INCENTIVE COMPENSATION

We provide annual cash incentive compensation through our Short-Term Performance Plan ("STPP"). The STPP provides for annual cash awards to NEOs based upon the achievement of pre-established stockholder-, customer-, and employee- focused objectives. All payments under the STPP are at risk. Payments are made only if performance goals are achieved, and awards may be less or greater than targeted amounts based upon actual performance. Payments under the STPP are intended to reward achievement of short-term goals that contribute to stockholder and customer value, as well as individual contributions to successful operations.

2018 Target Awards. Each year, the Compensation Committee approves a target level of compensation under the STPP for each of our NEOs. This target level of compensation is expressed as a percentage of base salary.

In October 2018, the target award level for Mr. Fletcher was increased to 90% of base salary in recognition of his appointment to President of WEC Energy Group. Therefore, Mr. Fletcher's STPP payout level reflects a 70% target level for nine months and a 90% target level for three months.

The year-end 2018 target awards for each NEO (other than Messrs. Klappa, Kuester and Leverett, who are discussed above) are set forth in the chart below.

Executive Officer	Target STPP Award as a Percentage of Base Salary
Mr. Lauber	80%
Mr. Fletcher	90%
Ms. Kelsey	70%
Mr. Keyes	75%

The target award levels of each officer named in the table above reflect median incentive compensation practices as indicated by the market data.

For 2018, the possible payout for any NEO ranged from 0% of the target award to 210% of the target award, based upon performance.

2018 Financial Goals under the STPP. The Compensation Committee adopted the 2018 STPP with a continued principal focus on financial results. In December 2017, the Compensation Committee approved WEC Energy Group's earnings per share (75% weight) and cash flow (25% weight) as the primary performance measures to be used in 2018. For those officers whose positions primarily relate to utility operations in Wisconsin (including Mr. Fletcher until he was appointed President of WEC Energy Group in October 2018) the Compensation Committee approved WEC Energy Group's earnings per share (25% weight) and cash flow (25% weight), as well as aggregate net income of WEC Energy Group's Wisconsin utility operations (50% weight), as the primary performance measures to be used in 2018. We believe earnings per share and cash flow are key indicators of financial strength and performance, and are recognized as such by the investment community. Utility net income is an important financial measure as it is an indicator of the return on equity earned by our utilities, and in order to meet our earnings per share targets it is important that our utilities earn at or close to their allowed rates of return.

In October 2018, the target award level for Mr. Fletcher was increased from 70% to 90% of base salary in recognition of his appointment to President of WEC Energy Group. Therefore, Mr. Fletcher's STPP payout level is based upon a combination of (i) WEC Energy Group's Wisconsin utility operations' performance against their 2018 performance goals and (ii) WEC Energy Group's performance against its 2018 performance goals.

In January 2018, the Compensation Committee approved the performance goals under the STPP for WEC Energy Group's earnings per share as set forth in the chart below.

Earnings Per Share Performance Goal	Earnings Per Share CAGR	Payout Level
$3.19	3.2%	25%
$3.21	3.9%	50%
$3.24	5.0%	100%
$3.26	5.5%	135%
$3.30	6.8%	200%

If the Company's performance falls between these levels, the payout level with respect to earnings per share is determined by interpolating on a straight line basis the appropriate payout level.

Although WEC Energy Group achieved earnings per share of $3.79 based on generally accepted accounting principles ("GAAP"), because this result included a one-time adjustment of $0.65 per share related to the impact of the Tax Cuts and Jobs Act of 2017 (the "Tax Legislation"), the Compensation Committee determined that the appropriate earnings per share measure on which to base the 2018 performance goals was WEC Energy Group's 2017 adjusted earnings per share of $3.14.

The Company's growth plan, which has been communicated to the public, calls for a long-term compound annual growth rate ("CAGR") in earnings per share of 5.0% to 7.0%. At the time the Compensation Committee was establishing targets for 2018, this CAGR was measured off a 2017 base of $3.09 per share, which represented the mid-point of the 2017 annual earnings guidance. We believe that this CAGR, plus our continued growth in dividends, supports a premium valuation as compared to the Company's peers. Therefore, the Compensation Committee tied the target (100%) payout level to achievement of the low end of the target CAGR range (5.0%), and the above-target payout level to achievement of a 5.5% CAGR. The Compensation Committee tied the maximum payout level (200%) to achievement of a 6.8% CAGR.

In January 2018, the Compensation Committee approved the initial performance goals under the STPP for WEC Energy Group's cash flow. At that time, management informed the Compensation Committee that it might recommend new cash flow

performance goals for consideration later in the year based upon the impact of the Tax Legislation and voluntary contributions to subsidiary pension plans. During 2018, WEC Energy Group returned $100 million to customers related to the impacts of the Tax Legislation and one of the Company's utility subsidiaries made a voluntary contribution of $60 million to its pension plan. As a result, in October 2018, the Compensation Committee revised the cash flow performance goals, which are set forth in the chart below ($ in millions).

Cash Flow	Payout Level
$1,700	25%
$1,750	50%
$1,800	100%
$1,850	135%
$1,950	200%

If the Company's performance falls between these levels, the payout level with respect to cash flow is determined by interpolating on a straight-line basis the appropriate payout level.

The Compensation Committee based the cash flow performance level goals on WEC Energy Group's funds from operations ("FFO"). FFO is calculated by taking "cash provided by operating activities" and eliminating certain accruals and other items related to capital spending. GAAP requires these items to be recorded as part of cash from operations, but management views them as related to the Company's capital expenditure program. The Compensation Committee believes that basing the cash flow performance goals on FFO provides a more accurate measurement of the cash generated by the Company's operations that is available for capital investment, which is the Company's primary driver for earnings growth. FFO is not a measure of financial performance under GAAP, and the Company's calculation may differ from similarly titled measures used by other companies or securities rating agencies.

In January 2018, the Compensation Committee approved the performance goals under the STPP for the Wisconsin utilities' net income (based upon WEC Energy Group's earnings per share performance goals) as set forth in the chart below ($ in millions).

Net Income	Weighted Return on Equity	Payout Level
$588	9.92%	25%
$593	10.00%	50%
$598	10.08%	100%
$603	10.16%	135%
$613	10.32%	200%

2018 Financial Performance under the STPP. In January 2019, the Compensation Committee reviewed our actual performance for 2018 against the financial and operational performance goals established under the STPP, subject to final audit.

WEC Energy Group's 2018 financial performance satisfied the maximum payout level established for earnings per share, cash flow, and net income for the Wisconsin utilities. WEC Energy Group's earnings per share were $3.34 for 2018. WEC Energy Group's cash flow, based on FFO, was $2,372 million, and the Wisconsin utilities' net income was $617 million for 2018. Our cash flow result is not a measure of financial performance under GAAP.

By satisfying the maximum payout level with respect to these financial measures, the NEOs earned 200% of the target award from the financial goal component of the STPP.

2018 WEC Energy Group Operational Goals and Performance under the STPP. Similar to prior years, in December 2017 and January 2018, the Compensation Committee also approved operational performance measures and targets under the STPP. Annual incentive awards could be increased or decreased by up to 10% of the actual award based upon WEC Energy Group's performance in the operational areas of customer satisfaction (5% weight), safety (2.5% weight), and supplier and workforce diversity (2.5% weight). The Compensation Committee recognizes the importance of strong operational results to the success of the Company and has identified these three operational areas in particular as being critical to that success.

The Compensation Committee measures customer satisfaction levels based upon the results of surveys that an independent third party conducts of customers who had direct contact with our utilities during the year, which measure (i) customers' satisfaction with the respective utility overall, and (ii) customers' satisfaction with respect to the particular transactions with the applicable utility. Safety is measured based upon performance against the number of lost time injuries and OSHA recordable incidents, as well as the number of Near Miss/Unsafe Condition ("NMUC") Reports filed. NMUC reporting is designed to proactively identify and take action on potential safety risks before an incident occurs (unsafe conditions); and to learn from near-miss incidents that have occurred, but did not result in an injury or damage.

The operational performance measures are based upon recommendations from management and take into consideration both current year performance and our longer-term objective of achieving top quartile performance of all of our principal utilities. The Compensation Committee reviews management's recommendations and may make adjustments to the performance measures if it feels changes are necessary. The following table provides the operational goals approved by the Compensation Committee for 2018, as well as WEC Energy Group's performance against these goals:

Operational Measure	Below Goal	Goal	Above Goal	Final Result
Customer Satisfaction Percentage of "Highly Satisfied":	-5.00%	0.00%	+5.00%	
Company	<75.7%	75.7% - 78.8%	>78.8%	79.2%
Transaction	<79.2%	79.2% - 82.2%	>82.2%	82.4%
Safety:	-2.50%	0.00%	+2.50%	
Lost Time Injury - Incidents	>67	39 - 67	<39	55
OSHA Recordable - Incidents	>206	135 - 206	<135	193
Near Miss / Unsafe Condition Reports	<20,100	20,100 - 23,992	>23,992	25,146
Diversity:	-2.50%	0.00%	+2.50%	
Supplier ($ in Millions)	<196.1	196.1 - 231.7	>231.7	263.1
Workforce - Assessment	Not Met	Met	Exceeded	Met

Based on the operational results listed in the table above, WEC Energy Group's performance with respect to operational goals generated a 7.08% increase to the compensation awarded under the STPP for 2018.

2018 Wisconsin Utilities Operational Goals and Performance under the STPP. For those officers whose positions in 2018 primarily related to utility operations in Wisconsin, STPP awards could be increased or decreased by up to 10% based upon performance in the operational areas of customer satisfaction (5% weight), safety (2.5% weight), and supplier diversity (1.25% weight) for WEC Energy Group's Wisconsin utility operations, as well as WEC Energy Group's performance in the operational area of workforce diversity (1.25% weight).

The Compensation Committee measures customer satisfaction levels based upon the results of surveys that an independent third party conducts of customers who had direct contact with our Wisconsin utilities during the year, which measure (1) customers' satisfaction with the specific Wisconsin utility overall, and (2) customers' satisfaction with respect to their particular transactions with their specific utility. Safety is measured based upon performance against the number of lost time injuries and OSHA recordable incidents, as well as the number of NMUC Reports filed.

The following table provides the operational goals approved by the Compensation Committee for 2018 for WEC Energy Group's Wisconsin utility operations, as well as the Company's performance against these goals:

Operational Measure	Below Goal	Goal	Above Goal	Final Result
Customer Satisfaction Percentage of "Highly Satisfied":	-5.00%	0.00%	+5.00%	
Company	<78.8%	78.8% - 81.7%	>81.7%	81.8%
Transaction	<82.0%	82.0% - 85.1%	>85.1%	84.7%
Safety:	-2.50%	0.00%	+2.50%	
Lost Time Injury - Incidents	>25	13 - 25	<13	31
OSHA Recordable - Incidents	>105	65 - 105	<65	109
Near Miss / Unsafe Condition Reports	<14,538	14,538 - 17,792	>17,792	15,012
Diversity:	-2.50%	0.00%	+2.50%	
Supplier ($ in Millions)	<105.0	105.0 - 120.0	>120.0	138.2
Workforce - Assessment	Not Met	Met	Exceeded	Met

Based upon the operational results listed in the table above, the Wisconsin utilities' performance with respect to operational goals generated a 2.08% increase to the compensation awarded under the STPP for 2018.

The Compensation Committee retains the right to exercise discretion in adjusting awards under the STPP when it deems appropriate, but did not factor individual contributions into determining the amount of the awards for the NEOs for 2018. Because the Company's performance against the financial and operational goals resulted in significant STPP awards in 2018, the Compensation Committee determined that no further adjustments based upon individual contributions or otherwise were appropriate.

Based upon the Company's performance against the financial and operational goals established by the Compensation Committee, Mr. Klappa received annual incentive cash compensation under the STPP of $3,541,124 for 2018. This represented 248% of his annual base salary. Messrs. Lauber, Fletcher, Kuester, and Keyes, and Ms. Kelsey, each received annual cash incentive compensation for 2018 under the STPP equal to 166%, 157%, 198%, 155%, and 145% of their respective annual base salaries, representing 207.08% of the target award for each officer, other than Mr. Fletcher, whose incentive compensation payout was 204.05% of his target award. Mr. Fletcher's STPP payout is based upon a combination of (i) the number of days he served as President of WEC Energy Group with a target award of 90% of base pay multiplied by WEC Energy Group's payout level of 207.08% of his target award and (ii) the number of days he served as President of WEC Energy Group's Wisconsin utility operations with a target award of 70% of base salary multiplied by WEC Energy Group's Wisconsin utility operations' payout level of 202.08% of his target award. For additional information about Messrs. Klappa's, Kuester's, and Leverett's receipt of incentive compensation under the STPP, see "Determination of Messrs. Klappa's and Kuester's 2018 Compensation" and "Mr. Leverett's 2018 Compensation" on page P-40.

LONG-TERM INCENTIVE COMPENSATION

The Compensation Committee administers our 1993 Omnibus Stock Incentive Plan, amended and restated effective January 1, 2016, which is a stockholder-approved, long-term incentive plan designed to link the interests of our executives and other key employees to creating long-term stockholder value. It allows for various types of awards tied to the performance of our common stock, including stock options, stock appreciation rights, and restricted stock. The Compensation Committee also administers the WEC Energy Group Performance Unit Plan, under which the Compensation Committee may award performance units. The Compensation Committee primarily uses (1) performance units, including dividend-equivalents, (2) stock options, and (3) restricted stock to deliver long-term incentive opportunities.

Performance Units. Each year, the Compensation Committee makes annual grants of performance units under the Performance Unit Plan. The performance units are designed to provide a form of long-term incentive compensation that aligns the interests of management with those of a typical utility stockholder who is focused not only on stock price appreciation but also on dividends. Payouts are based upon the Company's level of "total stockholder return" (stock price appreciation plus reinvested dividends) in comparison to a peer group of companies over a three-year performance period, and may be adjusted based upon the Company's performance against one or more Additional Performance Measures. The performance units are settled in cash.

Selection of Additional Performance Measure(s). "Additional Performance Measure" is defined as the performance criterion or criteria (if any) that the Compensation Committee selects, in its sole discretion, based upon the attainment of specific levels of performance by WEC Energy Group. Performance units vest in an amount between 0% and 175% of the target award based upon WEC Energy Group's comparative total stockholder return over a three-year performance period. However, the vesting percentage may be adjusted based upon WEC Energy's performance against the Additional Performance Measure(s). The Additional Performance Measure(s), if any, must be selected by the Compensation Committee at the beginning of the three-year performance period. For each year during the performance period, the Compensation Committee will select the target(s) for the Additional Performance Measure(s) and the potential adjustment to the vesting percentage for that year based upon achievement of the Additional Performance Measure(s) relative to the selected target(s). The actual adjustment, if any, to the vesting percentage based upon the Additional Performance Measure(s) will be determined annually. In no event will any adjustment cause the vesting percentage over the three-year performance period to be less than zero.

Short-Term Dividend Equivalents. We increase the number of unvested performance units as of any date that we declare a cash dividend on our common stock by the amount of short-term dividend equivalents a participant is entitled to receive. Short-term dividend equivalents are calculated by multiplying (a) the number of unvested performance units held by a plan participant as of the related dividend record date by (b) the amount of cash dividend payable by the Company on a share of common stock; and (c) dividing the result by the closing price for a share of the Company's common stock on the dividend payment date. In effect, short-term dividend equivalents are credited and accumulated as reinvested dividends on each performance unit so that the performance units and accumulated dividends will be paid out at the end of the three-year performance period, rather than paying out the dividend equivalents annually on unearned performance units.

Short-term dividend equivalents are treated as additional unvested performance units and are subject to the same vesting, forfeiture, payment, termination, and other terms and conditions as the original performance units to which they relate. In addition, outstanding short-term dividend equivalents are treated as unvested performance units for purposes of calculating future short-term dividend equivalents.

Stock Options. Each year, the Compensation Committee also makes annual stock option grants as part of our long-term incentive program. These stock options have an exercise price equal to the fair market value of our common stock on the date of grant and expire on the 10th anniversary of the grant date. Since management benefits from a stock option award only to the extent our stock price appreciates above the exercise price of the stock option, stock options align the interests of management with those of our stockholders in attaining long-term stock price appreciation.

Restricted Stock. The Compensation Committee also awards restricted stock as part of the long-term incentive plan, consistent with market practice. Similar to performance units, restricted stock aligns the interests of management with a typical utility stockholder who is focused on stock price appreciation and dividends.

Aggregate 2018 Long-Term Incentive Awards. Generally, when establishing the target value of long-term incentive awards and the appropriate mix of performance units, stock options, and restricted stock for each NEO, the Compensation Committee reviews the market compensation data and analysis provided by FW Cook. Based upon FW Cook's analysis, for 2018 the Compensation Committee determined that the long-term incentive awards would be weighted 65% performance units, 20% stock options, and 15% restricted stock for Messrs. Lauber, Fletcher, Leverett, and Keyes, and Ms. Kelsey. Target values also were presented to and approved by the Compensation Committee in December 2017.

With respect to Messrs. Klappa and Kuester, after consultation with FW Cook, the Compensation Committee determined that their long-term incentive awards would be weighted 80% restricted stock and 20% stock options. At the time, the Committee recognized that Messrs. Klappa's and Kuester's tenure with the Company would be significantly shorter than the other executive officers. Since the vesting percentage of performance units is based upon WEC Energy Group's total stockholder return over a three-year period, the Compensation Committee did not believe that performance units would accurately reflect the contributions of Messrs. Klappa and Kuester to the success of the Company over a shorter period of time.

Based upon the market data provided by FW Cook, we target the long-term incentive award to be at or near the market median value of long-term incentive compensation for each executive officer's position. All of the NEOs' long-term incentive awards were within this target range for 2018. For additional information on Messrs. Klappa's, Kuester's and Leverett's awards, see "Determination of Messrs. Klappa's and Kuester's 2018 Compensation" and "Mr. Leverett's 2018 Compensation" on page P-40.

2018 Stock Option Grants. In December 2017, the Compensation Committee approved the grant of stock options to each of our NEOs (other than Mr. Kuester) and established an overall pool of options that were granted to approximately 200 other employees. The option grants to the NEOs (other than Mr. Kuester) were made effective January 2, 2018, the first trading day of 2018. The options were granted with an exercise price equal to the average of the high and low prices reported on the NYSE for shares of WEC Energy Group common stock on the grant date. The options were granted in accordance with our standard practice of making annual stock option grants effective on the first trading day of each year, and the timing of the grants was not tied to the timing of any release of material information. The Compensation Committee granted Mr. Kuester's stock options effective March 1, 2018, the date he commenced service as Senior Executive Vice President of WEC Energy Group.

These stock options have a term of 10 years and vest 100% on the third anniversary of the date of grant. The vesting of the stock options may be accelerated in connection with a change in control or an executive officer's termination of employment under certain circumstances. See "Potential Payments upon Termination or Change in Control" beginning on page P-63 for additional information. Subject to the limitations of the 1993 Omnibus Stock Incentive Plan, the Compensation Committee has the power to amend the terms of any option (with the participant's consent). However, the Committee may not reduce the exercise price of existing options or cancel outstanding options and grant replacement options having a lower exercise price without stockholder approval.

For purposes of determining the appropriate number of options to grant to a particular NEO, the value of an option was determined based upon the Black-Scholes option pricing model. We use the Black-Scholes option pricing model for purposes of the compensation valuation. The following table provides the number of options granted to each NEO in 2018:

Executive Officer	Options Granted
Mr. Klappa	115,960
Mr. Lauber	26,465
Mr. Fletcher	16,055
Mr. Kuester	50,055
Ms. Kelsey	18,380
Mr. Leverett	120,925
Mr. Keyes	24,825

For financial reporting purposes, the stock options granted on January 2, 2018 had a grant date fair value of $8.68 per option for Messrs. Lauber, Leverett, and Keyes, and Ms. Kelsey, and a grant date fair value of $6.84 for Messrs. Klappa and Fletcher, who are considered to be "retirement eligible." The stock options granted on March 1, 2018 to Mr. Kuester, who is also "retirement eligible," had a grant date fair value of $5.95. The options granted to Messrs. Klappa, Fletcher and Kuester are presumed to have a shorter expected life, which results in a lower option value.

2018 Restricted Stock Awards. In December 2017, the Compensation Committee also approved the grant of restricted stock to each of our NEOs (other than Mr. Kuester) and established an overall pool of restricted stock that was granted to approximately 200 other employees. The grants to the NEOs were also made effective January 2, 2018 (other than Mr. Kuester). Mr. Kuester's grant of restricted stock was made effective March 1, 2018. Other than the shares granted to Messrs. Klappa and Kuester, the restricted stock vests in three equal annual installments beginning on January 2, 2019. The shares of restricted stock granted to Messrs. Klappa and Kuester vest in full on the one year anniversary of the grant date, reflecting the shorter tenure the Committee expected for Messrs. Klappa and Kuester.

The vesting of the restricted stock may be accelerated in connection with a termination of employment due to a change in control, death or disability, or by action of the Compensation Committee. Messrs. Klappa's and Kuester's restricted stock also fully vested if they resigned for "good reason," defined as a material diminution in their authority, duties or responsibilities, including, but not limited to, the Company's appointment of a successor Chief Executive Officer. The Compensation Committee wanted to appropriately incentivize Messrs. Klappa and Kuester to return to the Company while Mr. Leverett recovered from his stroke. See "Potential Payments upon Termination or Change in Control" beginning on page P-63 for additional information. Tax withholding obligations related to vesting may be satisfied, at the option of the executive officer, by withholding shares otherwise deliverable upon vesting or by cash. The NEOs have the right to vote the restricted stock and to receive cash dividends when the Company pays a dividend to our stockholders.

For purposes of determining the appropriate number of shares of restricted stock to grant to a particular NEO, the Compensation Committee used a value of $68.39 per share. This value was based upon the volume weighted price of WEC Energy Group's common stock for the ten trading days beginning on December 4, 2017, and ending on December 15, 2017. The Compensation Committee uses the volume-weighted price in order to minimize the impact of day-to-day volatility in the stock market.

The measurement period is customarily close to the grant date in order to shorten the timeframe between the calculation of the awards and the actual grant date. The following table provides the number of shares of restricted stock granted to each NEO in 2018:

Executive Officer	Restricted Stock Granted
Mr. Klappa	57,008
Mr. Lauber	2,439
Mr. Fletcher	1,479
Mr. Kuester	24,609
Ms. Kelsey	1,695
Mr. Leverett	11,145
Mr. Keyes	2,289

2018 Performance Units. In 2018, the Compensation Committee granted performance units to each of our NEOs (other than Messrs. Klappa and Kuester) and approved a pool of performance units that were granted to approximately 200 other employees. With respect to the 2018 performance units, the amount of the benefit that ultimately vests will be dependent upon the Company's total stockholder return over a three-year period ending December 31, 2020, as compared to the total stockholder return of the custom peer group described below. Total stockholder return is the calculation of total return (stock price appreciation plus reinvestment of dividends) based upon an initial investment of $100 and subsequent $100 investments at the end of each quarter during the three-year performance period. However, the vesting percentage may be adjusted based upon WEC Energy Group's performance against the Additional Performance Measure. For the 2018 performance unit awards, the Compensation Committee selected performance against the weighted average authorized return on equity of all WEC Energy Group's utility subsidiaries as the Additional Performance Measure.

Upon vesting, the performance units will be settled in cash in an amount determined by multiplying the number of performance units that have vested by the closing price of the Company's common stock on the last trading day of the performance period.

The 2018 performance unit peer group against which WEC Energy Group's performance will be measured includes:

- Alliant Energy Corporation
- Ameren Corporation
- American Electric Power Company
- CMS Energy Corporation
- Consolidated Edison, Inc.
- DTE Energy Co.
- Duke Energy Corp.
- Edison International
- Eversource Energy
- Evergy, Inc.
- FirstEnergy Corp.
- NiSource Inc.
- OGE Energy Corp.
- PG&E Corporation
- Pinnacle West Capital Corp.
- SCANA Corporation
- The Southern Company
- Xcel Energy Inc.

The peer group is chosen by the Compensation Committee, based upon management's recommendation and with the concurrence of FW Cook. This peer group was chosen because we believe these companies are similar to WEC Energy Group in terms of business model and long-term strategies, with a primary focus on regulated utility operations rather than a non-regulated business model. There is significant overlap between the performance unit peer group and the comparison group developed by FW Cook for purposes of benchmarking compensation levels. However, there are several companies that are different among the two groups because FW Cook places significant weight on the financial metrics of the companies included in its comparison group, whereas we focus more on operational measures for the performance unit peer group.

The required percentile ranking for total stockholder return and the applicable vesting percentage are set forth in the chart below.

Performance Percentile Rank	Vesting Percent
< 25th Percentile	0%
25th Percentile	25%
Target (50th Percentile)	100%
75th Percentile	125%
90th Percentile	175%

If the Company's rank is between the benchmarks identified above, the vesting percentage will be determined by interpolating on a straight line basis the appropriate vesting percentage. Unvested performance units generally are immediately forfeited upon a NEO's cessation of employment with WEC Energy Group prior to completion of the three-year performance period. However, the performance units will vest immediately at the target 100% rate upon the termination of the NEO's employment (1) by reason of disability or death or (2) after a change in control of WEC Energy Group. In addition, a prorated number of performance units (based upon the target 100% rate) will vest upon the termination of employment of the NEO by reason of retirement prior to the end of the three-year performance period.

In response to feedback we received from stockholders, the Compensation Committee amended the Performance Unit Plan, effective January 1, 2017, to provide for an Additional Performance Measure. For the 2018 performance unit awards, the Additional Performance Measure is the weighted average authorized return on equity ("ROE") of all WEC Energy Group's utility subsidiaries. In order for WEC Energy Group to meet its earnings per share targets, it is important that our utilities earn at or close to their allowed rates of return. The Company's performance against this measure may increase or decrease the vesting percentage of the performance units up to 10% over the three-year performance period. For 2018, the ROE targets and potential adjustments were set as follows:

If Actual Annual ROE is	The Annual Adjustment is	ROE Ranges
≤ 20 bp below the Authorized ROE	+ 3.33%	≥ 9.76%
21 - 30 bp below the Authorized ROE	0%	9.66% - 9.75%
> 30 bp below the Authorized ROE	(3.33)%	< 9.66%

These are the same ROE targets and potential adjustments that we used in connection with the Additional Performance Measure for the 2017 performance unit awards, which was the first year we included an Additional Performance Measure. WEC Energy Group's utility subsidiaries achieved a weighted average authorized ROE of 10.38% for 2018. This resulted in a 3.33% increase in the vesting percentage of the performance units awarded in January 2018 and January 2017. For purposes of determining the appropriate number of performance units to grant to a particular NEO, the Compensation Committee used a value of $68.39 per unit, the same value used for the restricted stock granted in January 2018.

The following table provides the number of performance units granted to each NEO effective January 2, 2018, at the 100% target level:

Executive Officer	Performance Units Granted
Mr. Klappa	—
Mr. Lauber	10,570
Mr. Fletcher	6,415
Mr. Kuester	—
Ms. Kelsey	7,340
Mr. Leverett	48,305
Mr. Keyes	9,915

2018 Payouts under Previously Granted Long-Term Incentive Awards. In 2016, the Compensation Committee granted performance unit awards to participants in the Performance Unit Plan. The terms of the performance units granted in 2016 were substantially similar to those of the performance units granted in 2018 described above, except that the 2016 performance units did not have an Additional Performance Measure. The required percentile ranks for total stockholder return and related vesting schedule were identical to that of the 2018 performance units.

Payouts under the 2016 performance units were based upon our total stockholder return for the three-year performance period ended December 31, 2018 against the same group of peer companies used for the 2018 performance unit awards.

Our total stockholder return was at the 78th percentile of the peer group for the three-year performance period ended December 31, 2018, resulting in the performance units vesting at a level of 134.3%. The actual payouts were determined by multiplying the number of vested performance units by the closing price of our common stock ($69.26) on December 31, 2018, the last trading day of the performance period. The actual payout to each NEO (other than Messrs. Klappa and Kuester, and Ms. Kelsey, who did not have any 2016 performance units outstanding) is reflected in the "Option Exercises and Stock Vested for Fiscal Year 2018" table.

COMPENSATION RECOUPMENT POLICY

Accountability is a fundamental value of WEC Energy Group. To reinforce this value through the Company's executive compensation program, the Compensation Committee has adopted a clawback policy that provides for the recoupment of incentive-based compensation in the event WEC Energy Group is required to prepare an accounting restatement due to material noncompliance with any financial reporting requirement under the securities laws (other than restatements permitted as a result of changes in accounting principles or interpretation). Pursuant to the policy, the Compensation Committee will recover from any current or former executive officer who has received incentive-based compensation during the three-year period preceding the date on which WEC Energy Group is required to prepare the accounting restatement, any portion of the incentive-based compensation paid in excess of what would have been paid to the executive officer under the restated financial results. The Company may also recover incentive-based compensation if an executive officer's employment is terminated for cause, or the executive officer violates a noncompetition or other restrictive covenant.

STOCK OWNERSHIP GUIDELINES

The Compensation Committee believes that an important adjunct to the long-term incentive program is significant stock ownership by officers who participate in the program, including the NEOs. Accordingly, the Compensation Committee has implemented stock ownership guidelines requiring officers who participate in the long-term incentive program to hold an amount of Company common stock and other equity-related Company securities that varies depending upon such officer's level.

In addition to shares owned outright, holdings of each of the following are included in determining compliance with our stock ownership guidelines: restricted stock; WEC Energy Group phantom stock units held in the Executive Deferred Compensation Plan; WEC Energy Group stock held in WEC Energy Group's 401(k) plans; performance units at target; and shares held in a brokerage account, jointly with an immediate family member or in a trust.

The guidelines require each executive officer, including the NEOs, to acquire (generally within five years of appointment as an executive officer) and hold common stock and other equity-related securities of the Company having a minimum fair market value ranging from 250% to 600% of base salary. The Compensation Committee believes these stock ownership guidelines discourage unreasonable risk taking by Company officers.

The Compensation Committee annually reviews whether executive officers are in compliance with these guidelines. The last review was completed in October 2018. The Compensation Committee determined that all NEOs are in compliance, or making sufficient progress towards compliance, with these guidelines.

PROHIBITION ON HEDGING AND PLEDGING

WEC Energy Group's Corporate Securities Trading Policy prohibits the use of any strategies or products, including derivatives and short-selling techniques, to hedge against potential changes in the value of WEC Energy Group's common stock. The policy, which is applicable to all directors and employees of the Company, including the NEOs, also prohibits the holding of WEC Energy Group securities in a margin account, as well as the pledging of WEC Energy Group securities as collateral for a loan.

LIMITED TRADING WINDOWS

Officers, including the NEOs, other key employees, and the Company's directors may only transact in WEC Energy Group securities during approved trading windows after satisfying mandatory pre-clearance requirements.

RETIREMENT PROGRAMS

We also maintain retirement plans in which our NEOs participate: a defined benefit pension plan of the cash balance type, a supplemental pension plan, individual letter agreements with some of the NEOs, and a 401(k) plan. We believe our retirement plans are a valuable benefit in the attraction and retention of our employees, including the NEOs. We believe that providing a foundation for long-term financial security for our employees, beyond their employment with the Company, is a valuable component of our overall compensation program which will inspire increased loyalty and improved performance. For more information about our retirement plans, see "Pension Benefits at Fiscal Year-End 2018" and "Retirement Plans."

Messrs. Klappa and Kuester had previously retired from the Company. For information regarding certain payments made to Messrs. Klappa and Kuester in connection with such retirements, see “Pension Benefits at Fiscal Year-End 2018.”

OTHER BENEFITS, INCLUDING PERQUISITES

We provide our executive officers, including the NEOs, with employee benefits and a limited number of perquisites. Except as specifically noted elsewhere in this proxy statement, the employee benefits programs in which executive officers participate (which provide benefits such as medical coverage, retirement benefits, annual contributions to a qualified savings plan, and moving and relocation costs) are generally the same programs offered to substantially all of the Company’s management employees.

The perquisites made available to executive officers include financial planning, membership in a service that provides health care and safety management when traveling outside the United States, reimbursement for expenses related to annual physical exam costs not covered by insurance, and limited spousal travel for business purposes. The Company also pays periodic dues and fees for club memberships for certain of the NEOs and other designated officers.

We customarily review market data regarding executive perquisite practices on an annual basis. Following our acquisition of Integrys Energy Group, the Compensation Committee undertook a thorough review of WEC Energy Group’s perquisite practices with FW Cook. At that time, FW Cook recommended to the Compensation Committee that the Company retain its package of perquisites. For 2018, the Compensation Committee again reviewed our package of perquisites with FW Cook and decided not to make any changes. WEC Energy Group has a legacy group of executives who are still eligible for gross-ups. We reimburse those executives for taxes paid on income attributable to the financial planning benefits provided to the executives only if the executive uses the Company’s identified preferred provider, AYCO. We believe the use of the preferred financial adviser provides administrative benefits and eases communication between Company personnel and the financial adviser.

We pay periodic dues and fees for certain club memberships as we have found that the use of these facilities helps foster better customer and community relationships. Officers, including the NEOs, are expected to use clubs for which the Company pays dues primarily for business purposes. We do not pay any additional expenses incurred for personal use of these facilities, and officers are required to reimburse the Company to the extent that it pays for any such personal use. The total annual club dues are included in the "Summary Compensation Table." We do not permit personal use of the airplane available to the Company. We do allow spousal travel if an executive’s spouse is accompanying the executive on business travel and the airplane is not fully utilized by Company personnel. There is no incremental cost to the Company for this travel, other than the reimbursement for taxes paid on imputed income attributable to the executives for this perquisite, as the airplane cost is the same regardless of whether or not an executive’s spouse travels. Any tax reimbursement is subject to the Company’s Tax Gross-Up Policy discussed below.

In addition, each of our executive officers is eligible to participate in an officer life insurance benefit. If an executive officer chooses to participate, upon such officer’s death while employed by the Company, a benefit is paid to his or her designated beneficiary in an amount equal to the value of three times the officer’s base salary at the time of death.

TAX GROSS-UP POLICY

The Compensation Committee adopted a formal policy that prohibits entry into any contract, agreement, or arrangement with any officer of the Company that obligates the Company to pay directly or reimburse the officer for any portion of the officer’s individual tax liability for benefits provided by the Company. Excluded from this policy are (1) agreements or arrangements entered into prior to December 2014 when the policy was adopted, (2) agreements or arrangements entered into prior to, and assumed by the Company in connection with, any merger or acquisition, or (3) plans or policies applicable to Company employees generally.

This policy formalized the Compensation Committee’s policy that had been in place since July 2011 to eliminate tax gross-ups on perquisites provided by the Company to its officers (except to officers who were already receiving gross-ups as of July 2011). Of the NEOs, Messrs. Lauber and Leverett were receiving gross-ups from the Company prior to July 2011.

In light of Mr. Klappa's retirement in May 2016, and subsequent re-appointment as CEO in 2017, and Mr. Kuester's retirement in January 2013 and subsequent appointment as Senior Executive Vice President in 2018, both Mr. Klappa and Mr. Kuester are deemed new employees for benefits purposes and are not eligible to receive gross-ups.

SEVERANCE BENEFITS AND CHANGE IN CONTROL

Several years ago, the Compensation Committee determined that it would no longer offer severance and change in control benefits in employment agreements. Therefore, Messrs. Klappa, Lauber, Kuester, and Keyes, and Ms. Kelsey, have not entered into an employment agreement that provides for these benefits. However, they are eligible to participate in the Company's Severance Pay Plan. Prior to that time, each of Messrs. Fletcher and Leverett entered into an employment agreement with the Company, which includes severance and change in control provisions. For a discussion of the severance and change in control benefits available under these agreements, and to our executive officers generally, see "Potential Payments upon Termination or Change in Control."

In addition, our supplemental pension plan provides that in the event of a change in control, participants will be entitled to a lump sum payment of amounts due under the plan if employment is terminated within 18 months of the change in control.

IMPACT OF PRIOR COMPENSATION

The Compensation Committee does not believe it is appropriate to consider the amounts realized or realizable from prior incentive compensation awards when establishing future levels of short-term and long-term incentive compensation.

SECTION 162(m) OF THE INTERNAL REVENUE CODE

Certain components of the Company's compensation program were designed to ensure the deductibility of compensation based on tax regulations in effect at the time the compensation was awarded, including Section 162(m). Section 162(m) of the Internal Revenue Code limits the deductibility of certain executives' compensation that exceeds $1,000,000 per year. For tax years prior to 2018, compensation over $1,000,000 per year could be deducted by the Company if such compensation was performance-based under Section 162(m) and issued through a plan that had been approved by stockholders. Starting with compensation awarded in 2018, the Tax Cuts and Jobs Act of 2017 eliminated the performance-based compensation exception under 162(m) for compensation over $1,000,000.

COMPENSATION COMMITTEE REPORT

The Compensation Committee has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management and, based on such review and discussions, the Compensation Committee recommended to the Board that the Compensation Discussion and Analysis be included in this proxy statement.

The Compensation Committee

John F. Bergstrom, Committee Chair
Thomas J. Fischer
Ulice Payne, Jr.

EXECUTIVE COMPENSATION TABLES

The following table summarizes total compensation awarded to, earned by, or paid to WEC Energy Group's Chief Executive Officer ("CEO"), Chief Financial Officer ("CFO"), and each of the other individuals identified in the table below (the "NEOs").

SUMMARY COMPENSATION TABLE

Name and Principal Position	Year	Salary ($)	Bonus ($)	(5) Stock Awards ($)	(6) Option Awards ($)	(7) Non-Equity Incentive Plan Compensation ($)	(8) Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	(9)(10) All Other Compensation ($)	Total ($)	Total Without Change in Pension Value ($)
Gale E. Klappa[1] Executive Chairman	2018	1,425,000	—	3,763,383	793,166	3,541,124	158,568	181,752	9,862,993	9,862,993
	2017	2,225,000	—	250,012	—	—	2,529,057	27,102	5,031,171	2,593,579
	2016	589,043	—	7,427,755	816,752	1,179,632	925,719	210,435	11,149,336	10,250,269
Scott J. Lauber Senior Executive Vice President, CFO and Treasurer	2018	574,711	—	858,790	229,716	952,418	22,857	76,186	2,714,678	2,714,678
	2017	467,321	—	534,890	137,001	764,441	93,343	66,124	2,063,120	1,977,525
	2016	351,784	—	158,886	38,371	513,010	65,818	38,116	1,165,985	1,103,685
J. Kevin Fletcher[1] President and Chief Executive Officer	2018	504,733	—	521,122	109,816	792,078	739,652	52,100	2,719,501	2,023,895
	2017	436,800	—	535,648	137,199	633,095	1,198,310	44,062	2,985,114	1,800,225
	2016	411,345	—	336,818	81,425	606,866	671,274	39,869	2,147,597	1,482,133
Frederick D. Kuester[2] Senior Executive Vice President	2018	638,481	—	1,476,294	297,827	1,267,350	33,485	266,998	3,980,435	3,980,435
Margaret C. Kelsey[2] Executive Vice President, General Counsel and Corporate Secretary	2018	515,000	—	596,445	159,538	746,535	41	88,223	2,105,782	2,105,782
Allen L. Leverett[3] Former President	2018	980,235	—	3,924,592	1,049,629	2,400,040	2,595,024	390,357	11,339,877	8,783,390
	2017	1,161,000	—	4,034,706	1,033,362	3,018,251	4,224,896	170,022	13,642,237	9,437,265
	2016	941,667	—	2,939,251	769,144	2,162,593	4,549,812	140,512	11,502,979	6,963,294
J. Patrick Keyes[4] Former Executive Vice President, Strategy	2018	579,676	—	805,647	215,481	900,309	137,664	75,557	2,714,334	2,609,178
	2017	562,792	—	920,228	235,718	885,736	122,780	73,214	2,800,468	2,682,669
	2016	546,400	—	889,965	215,067	904,320	111,973	73,034	2,740,759	2,630,909

Note: In order to show the effect that the year-over-year change in pension value had on total compensation, as determined under applicable SEC rules, we have included an additional column to show total compensation minus the change in pension value. The amounts reported in the Total Without Change in Pension Value column may differ substantially from the amounts reported in the Total column required under SEC rules and are not a substitute for total compensation. Total Without Change in Pension Value represents total compensation, as determined under applicable SEC rules, minus the change in pension value reported in the Change in Pension Value and Nonqualified Deferred Compensation Earnings column. The change in pension value is subject to many external variables, such as interest rates, that are not related to Company performance. Therefore, we do not believe a year-over-year change in pension value is helpful in evaluating compensation for comparative purposes.

(1) Mr. Klappa retired as CEO on May 1, 2016, but continued to serve as the Non-Executive Chairman of the Company's Board. After Mr. Leverett suffered a stroke in October 2017, the Company's Board appointed Mr. Klappa Chairman and CEO while Mr. Leverett recovered from his stroke. Mr. Klappa served in these roles until February 1, 2019, at which time he began serving as Executive Chairman. Mr. Fletcher, who was appointed to serve as President of WEC Energy Group on October 9, 2018, was appointed President and Chief Executive Officer of the Company effective February 1, 2019.

(2) Mr. Kuester, who was named Senior Executive Vice President effective March 1, 2018, and Ms. Kelsey, who was named Executive Vice President, General Counsel and Corporate Secretary effective January 1, 2018, became named executive officers in 2018. Therefore, no information has been provided for 2016 or 2017 for either officer.

(3) Mr. Leverett, who had been recovering from a stroke he suffered in October 2017, resigned as President effective October 10, 2018. Pursuant to the Company's standard medical leave policy, Mr. Leverett received 100% of his annual base salary until March 26, 2018, at which time he started receiving 80% of his base pay. Upon his resignation as President, Mr. Leverett began receiving payments under certain benefit plans of the Company, which are reflected in the All Other Compensation column. Mr. Leverett's annual incentive award under the STPP, included in the Non-Equity Incentive Plan Compensation column, was prorated to reflect the number of days Mr. Leverett served as President in 2018.

(4) Mr. Keyes resigned as Executive Vice President, Strategy and from his other officer positions with WEC Energy Group and its subsidiaries effective September 14, 2018, but remained an employee of the Company until January 4, 2019 to help transition his responsibilities.

(5) The amounts reported reflect the aggregate grant date fair value, as computed in accordance with FASB ASC Topic 718 excluding estimated forfeitures, of performance units and/or restricted stock awarded to each NEO in the respective year for which such amounts are reported. The amounts reported for the performance units are based upon the probable outcome as of the grant date of associated performance and market conditions, and are consistent with our estimate, as of the grant date, of aggregate compensation cost to be recognized over the three-year performance period. The actual value received by the executives from these awards may range from $0 to greater than the reported amounts, depending upon the Company's performance and the executive's number of additional years of service with the Company.

The value of the performance unit awards as of the grant date, assuming achievement of the highest level of performance and excluding any performance units resulting from short-term dividend equivalents and the Additional Performance Measure, for each of Messrs. Lauber, Fletcher, Leverett, and Keyes, and Ms. Kelsey, is $1,221,145, $741,084, $5,580,512, $1,145,426, and $847,963, respectively, for the 2018 awards. The value of the performance unit awards as of the grant date, assuming achievement of the highest level of performance and excluding any performance units resulting from short-term dividend equivalents and the Additional Performance Measure, for each of Messrs. Lauber, Fletcher, Leverett, and Keyes, is $760,647, $761,697, $5,736,862, and $1,308,597, respectively, for the 2017 awards. See "Option Exercises and Stock Vested For Fiscal Year 2017" for the amount of the actual payout with respect to the 2016 award of performance units. Mr. Klappa's 2016 grant of performance units vested pursuant to the terms of the Company's Performance Unit Plan upon his retirement on May 1, 2016. Not included are the performance unit awards resulting from short-term dividend equivalents and/or the Additional Performance Measure that may increase or, in the case of the Additional Performance Measure, decrease these amounts.

(6) The amounts reported reflect the aggregate grant date fair value, as computed in accordance with FASB ASC Topic 718 excluding estimated forfeitures, of options awarded to each NEO in the respective year for which such amounts are reported. The actual value received by the executives from these awards may range from $0 to greater than the reported amounts, depending upon Company performance. In accordance with FASB ASC Topic 718, we made certain assumptions in our calculation of the grant date fair value of the stock options. See "Stock Options" in Note 1(k) -- Stock-Based Compensation, in the Notes to Consolidated Financial Statements in our 2018 Annual Report on Form 10-K for a description of these assumptions. For 2018, the assumptions made in connection with the valuation of the stock options are the same as described in Note 1(k), except that the expected life of the options is 7.7 years for Messrs. Lauber, Leverett, and Keyes, and Ms. Kelsey, 4.3 years for Messrs. Klappa and Fletcher, and 3.5 years for Mr. Kuester. Mr. Kuester's options were granted effective March 1, 2018 as compared to the grant date of January 2, 2018 for the other NEOs. The change in the expected life of the options as set forth in Note 1(k) resulted from the fact that Messrs. Klappa, Fletcher, and Kuester are "retirement eligible" as of the grant date, and Messrs. Lauber, Leverett, and Keyes, and Ms. Kelsey, were not, whereas the assumption described in Note 1(k) is a weighted average of all option holders.

(7) Consists of the annual incentive compensation earned under WEC Energy Group's STPP.

(8) The amounts reported for 2018, 2017, and 2016 reflect the aggregate change in the actuarial present value of each applicable NEO's accumulated benefit under all defined benefit plans from December 31, 2017 to December 31, 2018, December 31, 2016 to December 31, 2017, and December 31, 2015 to December 31, 2016, respectively. The amounts reported for all three years also include above-market earnings on compensation that is deferred by the NEOs into the Prime Rate Fund under WEC Energy Group's Executive Deferred Compensation Plan. Above-market earnings represent the difference between the interest rate used to calculate earnings under the Plan and 120% of the applicable federal long-term rate prescribed by the Internal Revenue Code. The amounts earned for 2018 are shown below.

Name	Change in Pension Value ($)	Non-Qualified Deferred Compensation Earnings ($)	Total ($)
Gale E. Klappa	—	158,568	158,568
Scott J. Lauber	—	22,857	22,857
J. Kevin Fletcher	695,606	44,046	739,652
Frederick D. Kuester	—	33,485	33,485
Margaret C. Kelsey	—	41	41
Allen L. Leverett	2,556,487	38,537	2,595,024
J. Patrick Keyes	105,156	32,508	137,664

For 2018, 2017, and 2016, the applicable discount rate used to value pension plan liabilities moved from 3.65% to 4.30%, 4.15% to 3.65%, and 4.45% to 4.15%, respectively. As the discount rate decreases, the Company's pension funding obligation increases, and vice versa. The changes in the actuarial present values of the NEOs' pension benefits do not constitute cash payments to the NEOs.

The pension values reported represent only WEC Energy Group's obligation of the aggregate change in the actuarial present value of each NEO's accumulated benefit under all defined benefit plans. Messrs. Klappa, Fletcher, Kuester, and Leverett are entitled to receive pension benefits from prior employers. To the extent such prior employers are unable to pay their pension obligations, WEC Energy Group may be obligated to pay the total amount.

(9) During 2018, each NEO received financial planning services and the cost of an annual physical exam; Messrs. Klappa, Lauber, Fletcher, and Leverett were provided with membership in a service that provides healthcare and safety management when traveling outside the United States; Mr. Leverett received reimbursement for club dues. In 2018, the Company paid $78,181 for the lease of an apartment and related parking costs for Mr. Kuester as he transitioned from retirement back to Milwaukee, Wisconsin and into his new role as Senior Executive Vice President. Although Mr. Klappa utilized the benefit of spousal travel for business purposes in 2018, there was no associated cost to the Company as Mr. Klappa was not eligible to receive reimbursement for taxes paid on imputed income attributable to him for such travel.

(10) For Mr. Klappa, the amount reported in All Other Compensation for 2018 includes $23,453 attributable to WEC Energy Group's Directors' Charitable Awards Program in connection with Mr. Klappa's service on the Company's Board. See "Director Compensation" for a description of the Directors' Charitable Awards Program.

All Other Compensation for Messrs. Klappa, Lauber, Fletcher, Leverett, and Keyes, and Ms. Kelsey, for 2018 also consists of:

- Employer matching of contributions into the WEC Energy Group 401(k) plan in the amount of $11,000 for Messrs. Klappa, Lauber, Fletcher, and Keyes; $10,625 for Messrs. Kuester and Leverett; and $10,434 for Ms. Kelsey;
- Employer contributions into the WEC Energy Group 401(k) plan in the amount of $16,500 for Messrs. Klappa and Kuester, and Ms. Kelsey, and into the WEC Energy Group Non-Qualified Retirement Savings Plan in the amount of $69,000 for Mr. Klappa, $20,043 for Mr. Kuester, and $26,674 for Ms. Kelsey. These payments are in lieu of participation in the Company's pension plan;
- "Make-whole" payments under the Executive Deferred Compensation Plan that provides a match at the same level as the WEC Energy Group 401(k) plan (4% for up to 7% of wages) for all deferred salary and bonus not otherwise eligible for a match in the amounts of $46,000 for Mr. Klappa, $42,239 for Mr. Lauber, $33,700 for Mr. Fletcher, $16,914 for Ms. Kelsey, $143,089 for Mr. Leverett, and $46,557 for Mr. Keyes;
- Payments in the amount of $128,817 to Mr. Kuester under a previous consulting agreement with WEC Energy Group for services he provided in January and February 2018, prior to being named Senior Executive Vice President;
- Payments under a supplemental long-term benefit plan in the amount of $200,108 for Mr. Leverett; and
- Tax reimbursements or "gross-ups" for all applicable perquisites in the amounts of $7,202 and $14,454 for Messrs. Lauber and Leverett, respectively.

Other Information

In recognition of his appointment as President and Chief Executive Officer of WEC Energy Group in February 2019, Mr. Fletcher's 2019 annual base salary was increased to $1,004,000 and his target award under the STPP was increased to 125% of base salary. Additionally, in connection with Mr. Klappa's appointment as Executive Chairman in February 2019, his 2019 annual base salary and STPP target were set at $1,000,000 and 100% of base salary, respectively.

GRANTS OF PLAN-BASED AWARDS FOR FISCAL YEAR 2018

The following table shows additional data regarding incentive plan awards to the NEOs in 2018.

Name	Grant Date	Action Date [1]	Estimated Future Payouts Under Non-Equity Incentive Plan Awards [2]			Estimated Future Payouts Under Equity Incentive Plan Awards [3]			All Other Stock Awards: Number of Shares of Stock or Units [4]	All Other Option Awards [5]			Grant Date Fair Value of Stock and Option Awards
			Threshold ($)	Target ($)	Maximum ($)	Threshold (#)	Target (#)	Maximum (#)	(#)	Number of Securities Underlying Options (#)	Exercise or Base Price [6] ($/Sh)	Closing Market Price ($/Sh)	($)
Gale E. Klappa	1/18/18	—	427,500	1,710,000	3,591,000	—	—	—	—	—	—	—	—
	1/2/18	12/7/17	—	—	—	—	—	—	57,008	—	—	—	3,763,383
	1/2/18	12/7/17	—	—	—	—	—	—	—	115,960	66.015	65.77	793,166
Scott J. Lauber	1/18/18	—	114,980	459,920	965,832	—	—	—	—	—	—	—	—
	1/2/18	12/7/17	—	—	—	2,643	10,570	18,498	—	—	—	—	697,779
	1/2/18	12/7/17	—	—	—	—	—	—	2,439	—	—	—	161,011
	1/2/18	12/7/17	—	—	—	—	—	—	—	26,465	66.015	65.77	229,716
J. Kevin Fletcher	1/18/18	—	97,045	388,180	815,178	—	—	—	—	—	—	—	—
	1/2/18	12/7/17	—	—	—	1,604	6,415	11,226	—	—	—	—	423,486
	1/2/18	12/7/17	—	—	—	—	—	—	1,479	—	—	—	97,636
	1/2/18	12/7/17	—	—	—	—	—	—	—	16,055	66.015	65.77	109,816
Frederick D. Kuester	3/1/18	—	153,000	612,000	1,285,200	—	—	—	—	—	—	—	—
	3/1/18	2/23/18	—	—	—	—	—	—	24,609	—	—	—	1,476,294
	3/1/18	2/23/18	—	—	—	—	—	—	—	50,055	59.99	59.63	297,827
Margaret C. Kelsey	1/18/18	—	90,125	360,500	757,050	—	—	—	—	—	—	—	—
	1/2/18	12/7/17	—	—	—	1,835	7,340	12,845	—	—	—	—	484,550
	1/2/18	12/7/17	—	—	—	—	—	—	1,695	—	—	—	111,895
	1/2/18	12/7/17	—	—	—	—	—	—	—	18,380	66.015	65.77	159,538
Allen L. Leverett	1/18/18	—	289,743	1,158,973	2,433,843	—	—	—	—	—	—	—	—
	1/2/18	12/7/17	—	—	—	12,076	48,305	84,534	—	—	—	—	3,188,855
	1/2/18	12/7/17	—	—	—	—	—	—	11,145	—	—	—	735,737
	1/2/18	12/7/17	—	—	—	—	—	—	—	120,925	66.015	65.77	1,049,629
J. Patrick Keyes	1/18/18	—	108,689	434,757	912,990	—	—	—	—	—	—	—	—
	1/2/18	12/7/17	—	—	—	2,479	9,915	17,351	—	—	—	—	654,539
	1/2/18	12/7/17	—	—	—	—	—	—	2,289	—	—	—	151,108
	1/2/18	12/7/17	—	—	—	—	—	—	—	24,825	66.015	65.77	215,481

(1) Other than with respect to Mr. Kuester, on December 7, 2017, the Compensation Committee awarded the 2018 option, restricted stock, and performance unit grants effective the first trading day of 2018 (January 2, 2018). On February 23, 2018 the Compensation Committee awarded Mr. Kuester option and restricted stock grants effective March 1, 2018.

(2) Non-equity incentive plan awards consist of annual incentive awards under WEC Energy Group's STPP. For a more detailed description of the STPP, see the Compensation Discussion and Analysis.

(3) Consists of performance units awarded under the WEC Energy Group Performance Unit Plan. WEC Energy Group's Performance Unit Plan provides for short-term dividend equivalents. The number of performance units awarded will be increased as of any date that WEC Energy Group declares a cash dividend on its common stock by the amount of short-term dividend equivalents awarded. In effect, short-term dividend equivalents will be credited and accumulated as reinvested dividends on each performance unit so that the performance units and accumulated dividends will be paid out at the end of the performance units' three-year performance period, contingent upon the Company's performance. Therefore, the number of performance units reported at each of the threshold, target, and maximum levels in this table will increase by the number of short-term dividend equivalents earned. In addition, these amounts do not reflect any potential impact of the Company's performance against the Additional Performance Measure. For a more detailed description of the performance units, short-term dividend equivalents and Additional Performance Measure, see the Compensation Discussion and Analysis.

(4) Consists of restricted stock awarded under the 1993 Omnibus Stock Incentive Plan. For a more detailed description of the terms of the restricted stock, see the Compensation Discussion and Analysis.

(5) Consists of non-qualified stock options to purchase shares of WEC Energy Group common stock pursuant to the 1993 Omnibus Stock Incentive Plan. For a more detailed description of the terms of the options, see the Compensation Discussion and Analysis.

(6) The exercise price of the option awards is equal to the fair market value of WEC Energy Group's common stock on the date of grant. Fair market value is the average of the high and low prices of WEC Energy Group common stock, which is listed on the New York Stock Exchange, reported by Bloomberg, LLP on the grant date.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END 2018

The following table reflects the number and value of exercisable and unexercisable options as well as the number and value of other equity awards held by the NEOs at fiscal year-end 2018.

	Option Awards					Stock Awards			
Name	Number of Securities Underlying Unexercised Options: Exercisable (#)	Number of Securities Underlying Unexercised Options: Unexercisable [1] (#)	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock that Have Not Vested [2] (#)	Market Value of Shares or Units of Stock that Have Not Vested ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights that Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights that Have Not Vested [3] ($)
Gale E. Klappa	180,310	—	—	37.46	1/2/23	—	—	—	—
	302,535	—	—	41.025	1/2/24	—	—	—	—
	176,010	—	—	52.895	1/2/25	—	—	—	—
	190,830	—	—	50.925	1/4/26	—	—	—	—
	—	115,960	—	66.015	1/2/28	—	—	—	—
	—	—	—	—	—	59,866	4,146,319	—	—
Scott J. Lauber	3,650	—	—	34.875	1/3/22	—	—	—	—
	6,360	—	—	37.46	1/2/23	—	—	—	—
	9,560	—	—	41.025	1/2/24	—	—	—	—
	5,330	—	—	52.895	1/2/25	—	—	—	—
	—	6,720	—	50.925	1/4/26	—	—	—	—
	—	17,320	—	58.305	1/3/27	—	—	—	—
	—	26,465	—	66.015	1/2/28	—	—	—	—
	—	—	—	—	—	3,780	261,803	—	—
	—	—	—	—	—	—	—	14,202	983,631
	—	—	—	—	—	—	—	19,497	1,350,362
J. Kevin Fletcher	12,845	—	—	52.895	1/2/25	—	—	—	—
	—	14,260	—	50.925	1/4/26	—	—	—	—
	—	17,345	—	58.305	1/3/27	—	—	—	—
	—	16,055	—	66.015	1/2/28	—	—	—	—
	—	—	—	—	—	3,040	210,550	—	—
	—	—	—	—	—	—	—	14,222	985,016
	—	—	—	—	—	—	—	11,832	819,484
Frederick D. Kuester	—	50,055	—	59.99	3/1/28	—	—	—	—
	—	—	—	—	—	24,609	1,704,419	—	—
Margaret C. Kelsey	—	18,380	—	66.015	1/2/28	—	—	—	—
	—	—	—	—	—	1,695	117,396	—	—
	—	—	—	—	—	—	—	13,539	937,711
Allen L. Leverett	112,250	—	—	34.875	1/3/22	—	—	—	—
	197,360	—	—	37.46	1/2/23	—	—	—	—
	134,055	—	—	41.025	1/2/24	—	—	—	—
	77,955	—	—	52.895	1/2/25	—	—	—	—
	—	82,455	—	50.925	1/4/26	—	—	—	—
	—	42,679	—	58.325	5/2/26	—	—	—	—
	—	130,640	—	58.305	1/3/27	—	—	—	—
	—	120,925	—	66.015	1/2/28	—	—	—	—
	—	—	—	—	—	23,248	1,610,156	—	—
	—	—	—	—	—	—	—	107,114	7,418,716
	—	—	—	—	—	—	—	89,103	6,171,274
J. Patrick Keyes	10,460	—	—	34.875	1/3/22	—	—	—	—
	95,265	—	—	37.46	1/2/23	—	—	—	—
	57,335	—	—	41.025	1/2/24	—	—	—	—
	32,685	—	—	52.895	1/2/25	—	—	—	—
	—	37,665	—	50.925	1/4/26	—	—	—	—
	—	29,800	—	58.305	1/3/27	—	—	—	—
	—	24,825	—	66.015	1/2/28	—	—	—	—
	—	—	—	—	—	5,353	370,749	—	—
	—	—	—	—	—	—	—	24,433	1,692,230
	—	—	—	—	—	—	—	18,290	1,266,765

(1) All options reported in this column were granted ten years prior to their respective expiration date and vest 100% on the third anniversary of the grant date. Upon his separation from the Company effective January 4, 2019, Mr. Keyes forfeited the 29,800 and 24,825 options that expire on January 3, 2027 and January 2, 2028, respectively.

(2) Effective January 4, 2016, Messrs. Lauber, Fletcher, Leverett, and Keyes were granted restricted stock awards of 585; 1,239; 7,173; and 3,276 shares, respectively, which began vesting in three equal annual installments on January 4, 2017. Effective May 2, 2016, Mr. Leverett was granted a restricted stock award of 3,186 shares, which began vesting in three equal annual installments on May 2, 2017. Effective May 2, 2016, Mr. Klappa was granted a restricted stock award of 2,858 shares for his service as Non-Executive Chairman of the Company's Board of Directors, which will vest 100% on May 2, 2019. Effective January 3, 2017, Messrs. Lauber, Fletcher, Leverett, and Keyes were granted restricted stock awards of 1,719; 1,722; 12,975; and 2,958 shares, respectively, which began vesting in three equal annual installments on January 3, 2018. Effective January 2, 2018, Messrs. Lauber, Fletcher, Leverett, and Keyes, and Ms. Kelsey, were granted restricted stock awards of 2,439; 1,479; 11,145; 2,289; and 1,695 shares, respectively, which began vesting in three equal annual installments on January 2, 2019. Effective January 2, 2018, Mr. Klappa was granted a restricted stock award of 57,008 shares, which vested 100% on January 2, 2019. Effective March 1, 2018, Mr. Kuester was granted a restricted stock award of 24,609 shares which vested 100% on March 1, 2019. The vesting of the restricted stock granted to Messrs. Lauber, Fletcher, and Keyes, and Ms. Kelsey, may be accelerated in connection with a termination of employment due to a change in control, death or disability, or by action of the Compensation Committee. Upon his separation from the Company effective January 4, 2019, Mr. Keyes forfeited all unvested shares of restricted stock.

(3) The number of performance units reported were awarded in 2017 (first line) and 2018 (second line) and vest at the end of the three-year performance period ending December 31, 2019 and December 31, 2020, respectively. The number of performance units reported and their corresponding value are based upon a payout at the maximum amount for both 2017 and 2018. The number and value of the 2017 performance units includes performance units resulting from the grant of short-term dividend equivalents and Achievement of the Additional Performance Measure in 2017 and 2018. The number and value of the 2018 performance units includes performance units resulting from the grant of short-term dividend equivalents and achievement of the Additional Performance Measure in 2018.

OPTION EXERCISES AND STOCK VESTED FOR FISCAL YEAR 2018

This table shows the number and value of (1) stock options that were exercised by the NEOs, (2) restricted stock awards that vested, and (3) performance units that vested in 2018.

	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise (#)	Value Realized on Exercise [1] ($)	Number of Shares Acquired on Vesting [2] (#)	Value Realized on Vesting [3][4] ($)
Gale E. Klappa	246,618	8,560,938	4,429	281,668
	—	—	—	—
Scott J. Lauber	—	—	923	60,640
	—	—	3,763	260,624
J. Kevin Fletcher	72,455	2,378,464	1,360	89,371
	—	—	7,979	552,604
Frederick D. Kuester	168,790	5,725,198	—	—
	—	—	—	—
Margaret C. Kelsey	—	—	—	—
	—	—	—	—
Allen L. Leverett	—	—	8,984	590,383
	—	—	66,457	4,602,790
J. Patrick Keyes	—	—	3,029	199,052
	—	—	21,079	1,459,903

(1) Value realized upon the exercise of options is determined by multiplying the number of shares received upon exercise by the difference between the market price of WEC Energy Group common stock at the time of exercise and the exercise price.

(2) Reflects the number of shares of restricted stock that vested in 2018 (first line) and, the number of performance units that vested as of December 31, 2018, the end of the applicable three-year performance period (second line). The performance units were settled in cash.

(3) Restricted stock value realized is determined by multiplying the number of shares of restricted stock that vested by the fair market value of WEC Energy Group common stock on the date of vesting. We compute fair market value as the average of the high and low prices of WEC Energy Group common stock reported by Bloomberg, LLP on the vesting date.

(4) Performance units value realized is determined by multiplying the number of performance units that vested by the closing market price of WEC Energy Group common stock on December 31, 2018, the last trading day of the year.

PENSION BENEFITS AT FISCAL YEAR-END 2018

The following table sets forth information for each NEO regarding their pension benefits at fiscal year-end 2018 under WEC Energy Group's three different retirement plans discussed below.

Name	Plan Name	Number of Years Credited Service [1] (#)	Present Value of Accumulated Benefit [5][6] ($)	Payments During Last Fiscal Year[7] ($)
Gale E. Klappa[2]	WEC Energy Group Plan	13	274,933	—
	SERP	—	3,269,974	263,731
	Individual Letter Agreement	38.67	22,933,487	1,849,639
Scott J. Lauber	WEC Energy Group Plan	28.5	505,856	—
	SERP	28.5	165,017	—
	Individual Letter Agreement	—	—	—
J. Kevin Fletcher	WEC Energy Group Plan	7.17	139,950	—
	SERP	7.17	289,379	—
	Individual Letter Agreement	41.75	5,347,216	—
Frederick D. Kuester[3]	WEC Energy Group Plan	—	—	—
	SERP	9.17	864,942	61,739
	Individual Letter Agreement	40.33	9,271,352	661,782
Margaret C. Kelsey[4]	WEC Energy Group Plan	—	—	—
	SERP	—	—	—
	Individual Letter Agreement	—	—	—
Allen L. Leverett	WEC Energy Group Plan	15.5	340,716	—
	SERP	15.5	2,340,189	—
	Individual Letter Agreement	30	14,539,604	—
J. Patrick Keyes	WEC Energy Group Plan	7.67	148,788	—
	SERP	7.67	447,936	—
	Individual Letter Agreement	7.67	151,334	—

(1) Years of service are computed as of December 31, 2018, the pension plan measurement date used for financial statement reporting purposes. Messrs. Fletcher and Leverett have been credited with 34.58 and 14.5 years of service, respectively, pursuant to the terms of their Individual Letter Agreements ("ILAs"). Prior to his retirement in May 2016, Mr. Klappa was credited with 25.67 years of service pursuant to the terms of his ILA. Prior to his retirement in January 2013, Mr. Kuester was credited with 31.16 years of service pursuant to the terms of his ILA. The increase in the aggregate amount of each of Messrs. Klappa's, Fletcher's, Kuester's, and Leverett's accumulated benefit under all of WEC Energy Group's retirement plans resulting from the additional years of credited service is $20,981,171, $4,460,712, $8,192,804, and $10,536,282, respectively.

(2) Upon his retirement in May 2016, Mr. Klappa's ILA terminated. At that time, the number of years of credited service and the accumulated benefit effectively transferred to the WEC Energy Group Plan and the SERP. Payments related to the ILA were actually paid under the WEC SERP. Mr. Klappa is not accruing additional benefits under these plans in connection with his current service.

(3) Upon his retirement in January 2013, Mr. Kuester's ILA terminated. At that time, the number of years of credited service and the accumulated benefit effectively transferred to the WEC Energy Group Plan and the SERP. Payments related to the ILA were actually paid under the WEC SERP. Mr. Kuester is not accruing additional benefits under these plans in connection with his current service.

(4) Ms. Kelsey is not eligible to receive pension benefits under the WEC Energy Group Plan.

(5) The key assumptions used in calculating the actuarial present values reflected in this column are:

- Earliest projected unreduced retirement age based upon projected service:
  - For Mr. Klappa, age 65.67 (actual age at retirement).
  - For Mr. Lauber, age 60.
  - For Mr. Fletcher, age 65.
  - For Mr. Kuester, age 62.42 (actual age at retirement).
  - For Mr. Leverett, age 60.
  - For Mr. Keyes, age 55.58.
- Discount rate of 4.30%.
- Cash balance interest crediting rate of 5.00%.
- Form of payment:
  - Mr. Klappa's actual form of payment elected at retirement: WEC Energy Group Plan, SERP, and ILA - Single Life annuity
  - Mr. Lauber: WEC Energy Group Plan 50% lump sum / 50% life annuity; SERP - Life annuity
  - Messrs. Fletcher and Keyes: WEC Energy Group Plan 50% lump sum / 50% life annuity; SERP and ILA - Life annuity.
  - Mr. Kuester''s actual form of payment elected at retirement: WEC Energy Group Plan - Lump Sum; SERP and ILA - 50% Joint & Survivor annuity
  - Mr. Leverett: WEC Energy Group Plan 50% lump sum / 50% life annuity; SERP and ILA - 5 annual installments.
- Mortality Table, for Messrs. Klappa's, Lauber's, Fletcher's, Kuester's life annuity, and Leverett's actuarial 5 annual installments - RP2014/ Male/White Collar with modified MP2017 projection.

(6) WEC Energy Group's pension benefit obligations to Messrs. Klappa, Fletcher, Kuester, and Leverett will be partially offset by pension benefits they are entitled to receive from their former employers. The amounts reported for Messrs. Klappa, Fletcher, Kuester, and Leverett, represent only WEC Energy Group's obligation of the aggregate actuarial present value of each of their accumulated benefit under all of the plans. The total aggregate actuarial present value of each of Messrs. Klappa's, Fletcher's, Kuester's, and Leverett's accumulated benefit under all of the plans is $31,010,886, $8,054,982, $13,374,898, and $17,861,925, respectively, $4,532,492, $2,278,437, $3,238,604, and $641,416 of which we estimate the prior employer is obligated to pay. If Messrs. Klappa, Fletcher, Kuester, and Leverett's former employer becomes unable to pay its portion of his respective accumulated pension benefit, WEC Energy Group may be obligated to pay the total amount.

(7) Messrs. Klappa and Kuester continued to receive retirement benefits under the SERP; however, payments under the WEC Energy Group Plan were suspended for Mr. Klappa at the time he resumed his role as an executive officer with the Company. Mr. Kuester's entire WEC Energy Group Plan balance was previously paid in the form of a lump sum; therefore no further benefit exists for him in this plan.

RETIREMENT PLANS

WEC Energy Group maintains four different plans providing for retirement payments and benefits for the NEOs: a defined benefit pension plan of the cash balance type ("WEC Energy Group Plan"); a supplemental executive retirement plan ("SERP"); ILAs; and the WEC Energy Group Retirement Savings Plan, which is a 401(k) plan. The compensation currently considered for purposes of the retirement plans (other than the WEC Energy Group Plan and SERP) for Messrs. Fletcher and Leverett is $1,022,337 and $3,177,680, respectively. These amounts represent the average compensation (consisting of base salary and annual incentive compensation) for the 36 highest consecutive months. For Messrs. Lauber and Keyes, the compensation considered for purposes of the retirement plans (other than the WEC Energy Group Plan) is $1,334,961 and $1,439,693, respectively. These amounts represent their 2018 base salary, plus their 2017 STPP award paid in 2018. As of December 31, 2018, Messrs. Lauber, Fletcher, Leverett, and Keyes currently have or are considered to have 28.5, 41.75, 30, and 7.67 credited years of service, respectively, under the various plans described below. Messrs. Lauber and Keyes were not granted additional years of credited service.

See below for a discussion of the contributions made to the WEC Energy Group Retirement Savings Plan on behalf of Messrs. Klappa and Kuester, and Ms. Kelsey, who do not participate in the WEC Energy Group Plan.

The WEC Energy Group Plan

Most regular full-time and part-time employees, including several of the NEOs, participate in the WEC Energy Group Plan. The WEC Energy Group Plan bases a participant's defined benefit pension on the value of a hypothetical account balance. For individuals participating in the WEC Energy Group Plan as of December 31, 1995, a starting account balance was created equal to the present value of the benefit accrued as of December 31, 1994, under the plan benefit formula prior to the change to a cash balance approach. That formula provided a retirement income based on years of credited service and average compensation (consisting of base salary and annual incentive compensation) for the 36 highest consecutive months, with an adjustment to reflect the Social Security integrated benefit. In addition, individuals participating in the WEC Energy Group Plan as of December 31, 1995, received a special one-time transition credit amount equal to a specified percentage varying with age multiplied by credited service and 1994 base pay.

The present value of the accrued benefit as of December 31, 1994, plus the transition credit, was also credited with interest at a stated rate. For 1996 through 2007, a participant received annual credits to the account equal to 5% of base pay (including WEC Energy Group 401(k) plan pre-tax deferrals and other items), plus an interest credit on all prior accruals equal to 4% plus 75% of the annual time-weighted trust investment return for the year in excess of 4%. From 2008 through 2013, the interest credit percentage was set at either the long-term corporate bond third segment rate, published by the Internal Revenue Service, or 4%, whichever was greater.

Effective January 1, 2014, participants receive an annual credit to the account equal to 6% of base pay (including WEC Energy Group 401(k) plan pre-tax deferrals and other items), plus an interest credit on all prior accruals equal to a 5% fixed rate. For participants in the WEC Energy Group Plan on December 31, 2007 and December 31, 2013, their WEC Energy Group Plan benefit will never be less than the benefit accrued as of December 31, 2007 and December 31, 2013, respectively. The WEC Energy Group Plan benefit will be calculated under all three formulas to provide participants with the greater benefit; however, in calculating a participant's benefit accrued as of December 31, 2007 and December 31, 2013, interest credits as defined under each of the prior WEC Energy Group Plan formulas will be taken into account but not any additional pay credits.

Participants who were "grandfathered" as of December 31, 1995, as discussed below, will still receive the greater of the grandfathered benefit or the cash balance benefit.

The life annuity payable under the WEC Energy Group Plan is determined by converting the hypothetical account balance credits into annuity form.

Individuals who were participants in the WEC Energy Group Plan on December 31, 1995 were "grandfathered" so that they will not receive any lower retirement benefit than would have been provided under the formula in effect through December 31, 1995, had it continued. This amount continued to increase until December 31, 2010, at which time it was frozen. Upon retirement,

participants will receive the greater of this frozen amount or the accumulated cash balance.

For Mr. Lauber, estimated benefits under the grandfathered formula are higher than under the cash balance plan formula. Messrs. Fletcher, Leverett, and Keyes do not participate in the grandfathered formula. Although all of the NEOs (other than Mr. Kuester and Ms. Kelsey) participate in the cash balance plan formula, pursuant to the agreement discussed below, Mr. Leverett's total retirement benefits would be determined by the prior plan benefit formula if he were to retire at or after age 60. Mr. Leverett's agreement also provides that the prior plan benefit formula will continue to be applied until retirement, with no amounts frozen as of December 31, 2010. Mr. Leverett would receive the cash balance in his account if he was to terminate employment prior to attaining the age of 60. Although Mr. Leverett resigned as President of WEC Energy Group effective October 10, 2018, he remains an inactive employee, which is consistent with the Company's policy regarding similarly-situated management employees. Therefore, Mr. Leverett remains entitled to these retirement benefits.

Under the WEC Energy Group Plan, participants receive unreduced pension benefits upon reaching one of the following three thresholds: (1) age 65; (2) age 62 with 30 years of service; or (3) age 60 with 35 years of service.

Pursuant to the Internal Revenue Code, only $275,000 of pension eligible earnings (base pay and annual incentive compensation) may be considered for purposes of the WEC Energy Group Plan.

Supplemental Executive Retirement Plans and Individual Letter Agreements

Designated officers of WEC Energy Group, including all of the NEOs (other than Ms. Kelsey) participate in the SERP, which is part of the Supplemental Pension Plan (the "SPP") adopted to comply with Section 409A of the Internal Revenue Code. The SERP provides monthly supplemental pension benefits to participants, which will be paid out of unsecured corporate assets, or the grantor trust described below, in an amount equal to the difference between the actual pension benefit payable under the WEC Energy Group Plan and what such pension benefit would be if calculated without regard to any limitation imposed by the Internal Revenue Code on pension benefits or covered compensation, including amounts deferred to the WEC Energy Group Executive Deferred Compensation Plan. Except for a "change in control" of WEC Energy Group, as defined in the SPP, and pursuant to the terms of the ILAs discussed below, no payments are made until after the participant's retirement at or after age 60 or death. If a participant in the SERP dies prior to age 60, his or her beneficiary is entitled to receive retirement benefits under the SERP. Although Messrs. Klappa and Kuester remain participants in the SPP, they no longer accrue any benefits under the plan as a result of their earlier retirements. In addition, although Mr. Keyes remains a participant in the SPP, he no longer accrues any benefits under the plan as a result of his separation from the Company.

WEC Energy Group entered into an individual letter agreement with Mr. Klappa when he first commenced employment in 2003 to provide him with supplemental retirement benefits upon retirement at or after age 60. The supplemental retirement payments are intended to make the total retirement benefits payable to Mr. Klappa comparable to that which would have been received under the WEC Energy Group Plan as in effect on December 31, 1995, had the defined benefit formula then in effect continued until his retirement, calculated without regard to Internal Revenue Code limits, and as if Mr. Klappa had started participation in the WEC Energy Group Plan. Pursuant to the terms of the agreement, which terminated upon Mr. Klappa's retirement in May 2016, Mr. Klappa's benefits under the WEC Energy Group Plan and the SERP are being paid under the prior plan benefit formula as in effect on December 1, 1995, and as if Mr. Klappa had started with WEC Energy Group at age 27. As a result, Mr. Klappa had 38.67 years of credited service under the WEC Energy Group Plan and the SERP upon his retirement in May 2016.

WEC Energy Group entered into an agreement with Mr. Fletcher to provide him with supplemental retirement benefits upon his retirement, provided he completed one year of service with the Company. The supplemental retirement payments are intended to make the total retirement benefits payable to Mr. Fletcher comparable to that which would have been received under his prior employer's defined benefit pension plan, calculated without regard to Internal Revenue Code limits, and as if Mr. Fletcher's employment continued with the prior employer and the defined benefit formula then in effect under the prior employer's plan continued to his retirement. The retirement benefits payable as a result of this agreement will be offset by the value of any qualified and non-qualified defined benefit pension plan of the prior employer.

WEC entered into an individual letter agreement with Mr. Kuester when he first commenced employment in 2003 that was similar to Mr. Klappa's agreement to provide him with supplemental retirement benefits upon retirement at or after age 60. Pursuant to the terms of the agreement, which terminated upon Mr. Kuester's retirement in January 2013, Mr. Kuester's benefits under the WEC Energy Group Plan and the SERP are being paid under the prior plan benefit formula as in effect on December 1, 1995, and as if Mr. Kuester had started with WEC Energy Group at age 22. As a result, Mr. Kuester had 40.33 years of credited service under the WEC Energy Group Plan and the SERP upon his retirement in January 2013.

WEC Energy Group entered into an agreement with Mr. Leverett that was similar to Mr. Klappa's agreement to provide him with supplemental retirement benefits upon retirement at or after age 60. The supplemental retirement payments are intended to make the total retirement benefits payable to Mr. Leverett comparable to that which would have been received under the WEC Energy Group Plan as in effect on December 31, 1995, had the defined benefit formula then in effect continued until his retirement, calculated without regard to Internal Revenue Code limits, and as if Mr. Leverett had started participation in the WEC

Energy Group Plan on January 1, 1989. The retirement benefits payable to Mr. Leverett will be offset by the value of any qualified or non-qualified defined benefit pension plans of prior employers.

Mr. Leverett's agreement also provides for a pre-retirement spousal benefit to be paid to his spouse in the event of his death while employed by the Company. The benefit payable is equal to the amount which would have been received by Mr. Leverett's spouse under the WEC Energy Group Plan as in effect on December 31, 1995, had the benefit formula then in effect continued until Mr. Leverett's death, calculated without regard to Internal Revenue Code limits, and as if Mr. Leverett had started at the age indicated above. The spousal benefit payable would be offset by one half of the value of any qualified or non-qualified deferred benefit pension plans of Mr. Leverett's prior employer.

WEC Energy Group entered into an agreement with Mr. Keyes when he was hired as Vice President and Treasurer in 2011 that provided for a supplemental pension benefit account, which was credited with $100,000. This account was credited with interest annually at the same rate as the WEC Energy Group Plan. The account balance would have vested at the earliest to occur of Mr. Keyes attaining age 60 or completion of 10 years of service; however, Mr. Keyes forfeited this benefit upon his separation from the Company.

The purpose of these agreements was to ensure that Messrs. Klappa, Fletcher, Leverett, and Keyes did not lose pension earnings by joining the executive management team at WEC Energy Group they otherwise would have received from their former employers. Without providing a means to retain these pension benefits, it would have been difficult for WEC Energy Group to attract these officers.

The SPP provides for a mandatory lump sum payment upon a change in control if the executive's employment is terminated within 18 months after the change in control. The Wisconsin Energy Corporation 2014 Rabbi Trust, a grantor trust, funds certain non-qualified benefits, including the SPP and the ILAs, as well as the Executive Deferred Compensation Plan and the Directors' Deferred Compensation Plan. See "Potential Payments upon Termination or Change in Control" later in this proxy statement for additional information.

WEC Energy Group Retirement Savings Plan

Effective January 1, 2015, all newly hired management employees, including executive officers, will receive an annual contribution equal to 6% of pension eligible wages from the Company into WEC Energy Group's 401(k) plan rather than participate in the WEC Energy Group Plan. Pension eligible wages consist of annual base salary and STPP payouts. In connection with this plan, the Compensation Committee adopted the WEC Energy Group Non-Qualified Retirement Savings Plan which provides "make-whole" benefits to address Internal Revenue Code limits on the amount of money that can be contributed to a 401(k) plan.

Since Messrs. Klappa and Kuester are considered new employees, they will no longer accrue additional benefits under the WEC Energy Group Plan; however, Messrs. Klappa and Kuester, along with Ms. Kelsey, are entitled to receive Company contributions to the 401(k) plan and Non-Qualified Retirement Savings Plan.

NONQUALIFIED DEFERRED COMPENSATION FOR FISCAL YEAR 2018

The following table reflects activity by the NEOs during 2018 in WEC Energy Group's Executive Deferred Compensation Plan discussed below.

Name	Executive Contributions in Last Fiscal Year [1] ($)	Registrant Contributions in Last Fiscal Year [1] ($)	Aggregate Earnings In Last Fiscal Year ($)	Aggregate Withdrawals / Distributions ($)	Aggregate Balance at Last Fiscal Year-End [2] ($)
Gale E. Klappa	84,404	46,000	353,452	947,996	6,722,197
Scott J. Lauber	189,344	42,239	58,628	—	1,693,064
J. Kevin Fletcher	531,410	33,700	125,979	—	2,803,514
Frederick D. Kuester	—	—	66,379	285,333	1,141,332
Margaret C. Kelsey	36,010	16,914	16,082	—	222,326
Allen L. Leverett	441,304	143,089	52,008	—	6,291,763
J. Patrick Keyes	921,638	46,557	(263,131)	—	5,897,325

(1) All of the amounts are reported as compensation in the "Summary Compensation Table" of this proxy statement.

(2) $227,270, $693,245, $3,556,960, and $2,678,095 of the reported amounts were reported as compensation in the Summary Compensation Tables in prior proxy statements for Messrs. Lauber, Fletcher, Leverett, and Keyes, respectively. Messrs. Klappa and Kuester reported $6,931,246 and $2,350,309, respectively, in the Summary Compensation Tables in prior proxy statements. The amounts reported in this column for Messrs. Klappa and Kuester are lower than these previously reported amounts because Messrs. Klappa and Kuester have been receiving distributions

under the WEC Energy Group Executive Deferred Compensation Plan. Ms. Kelsey became a named executive officer in 2018; therefore, no amounts were previously reported in prior proxy statements for her. The amount for Ms. Kelsey includes a $150,000 contribution from WEC Energy Group in 2017 that vests upon Ms. Kelsey's third anniversary with the Company.

Executive Deferred Compensation Plan

WEC Energy Group maintains two executive deferred compensation plans in which the NEOs participate: the Legacy WEC Energy Group Executive Deferred Compensation Plan (the "Legacy EDCP"), and the WEC Energy Group Executive Deferred Compensation Plan (the "EDCP") adopted effective January 1, 2005 to comply with Section 409A of the Internal Revenue Code. The Legacy EDCP provides that (1) amounts earned, deferred, vested, credited, and/or accrued as of December 31, 2004 are preserved and frozen so that these amounts are exempt from Section 409A and (2) no new employees may participate in the Legacy EDCP as of January 1, 2005. Since January 1, 2005, all deferrals have been made to the EDCP. The provisions of the EDCP as in effect on December 31, 2018 are described below, as are the payout provisions of the Legacy EDCP.

The EDCP. Under the plan, a participant may defer up to 50% of his or her base salary, annual incentive compensation and vested awards of performance units. Stock option gains and vested restricted stock may not be deferred into the EDCP. Generally, deferral elections are made annually by each participant for the upcoming plan year. The Company maintains detailed records tracking each participant's "account balance." In addition to deferrals made by the participants, the Company may also credit each participant's account balance by matching a certain portion of each participant's deferral. Such deferral matching is determined by a formula taking into account the matching rate applicable under the Company's 401(k) plan, the percentage of compensation subject to such matching rate, the participant's gross compensation eligible for matching, and the amount of eligible compensation actually deferred. Also, in our discretion, the Company may credit any other amounts, as appropriate, to each participant's account.

Mr. Kuester was not eligible to defer any compensation into the EDCP for 2018, nor was he eligible for any Company contributions to the EDCP.

Participants may elect to participate in the Company's stock measurement fund and/or the Prime Rate Fund. The Company tracks each participant's account balance as though the balance was actually invested in these funds. Fund elections are not actual investments, but are elections chosen only for purposes of calculating market gain or loss on deferred amounts for the duration of the deferral period. Each participant may select the amount of deferred compensation to be allocated among the two measurement funds. Contributions and deductions may be made to each participant's account based on the performance of the measurement fund(s) elected.

The annual rate of return for the calendar year ended December 31, 2018 for the WEC Energy Group Common Stock Fund and the Prime Rate Fund was 4.3% and 4.88%, respectively.

Each participant's account balance is debited or credited periodically based on the performance of the measurement fund(s) elected by the participant. Subject to certain restrictions, participants may make changes to their measurement fund elections by notice to the committee administering the plan.

At the time of his or her deferral election, each participant may designate a prospective payout election for any or the entire amount deferred, plus any amounts debited or credited to the deferred amount as of the designated payout. Amounts deferred into the EDCP may not be withdrawn at the discretion of the participant and a change to the designated payout delays the initial payment at least five years beyond the originally designated payout date. In addition, the Company may not limit payout amounts in order to deduct such amounts under Section 162(m) of the Internal Revenue Code.

The balance of a participant's account is payable on his or her retirement in either a lump sum payout or in annual installments, at the election of the participant. Upon the death of a participant after retirement, payouts are made to the deceased participant's beneficiary in the same manner as though such payout would have been made to the participant had the participant survived. In the event of a participant's termination of employment prior to retirement, the participant may elect to receive a payout beginning the year after termination in the amount of his or her account balance as of the termination date either in a lump sum or in annual installments over a period of five years. Disability is not itself a payment event until the participant terminates employment with WEC Energy Group or its subsidiaries. A participant's account balance will be paid out in a lump sum if the participant separates from service with WEC Energy Group or its subsidiaries within 18 months after a change in control of WEC Energy Group, as defined in the plan. The deferred amounts will be paid out of the general corporate assets or the assets of the Wisconsin Energy Corporation 2014 Rabbi Trust.

The Legacy EDCP. At the time of his or her deferral election, each participant designated a prospective payout election for any or the entire amount deferred, plus any amounts debited or credited to the deferred amount as of the designated payout. A participant may elect, at any time, to withdraw part (a minimum of $25,000) or all of his or her account balance, subject to a withdrawal penalty of 10%. Payout amounts may be limited to the extent to which they are deductible by the Company under Section 162(m) of the Internal Revenue Code.

The balance of a participant's account is payable on his or her retirement in either a lump sum payout or in annual installments, at the election of the participant. Upon the death of a participant after retirement, payouts are made to the deceased participant's beneficiary in the same manner as though such payout would have been made to the participant had the participant survived. In the event of a participant's termination of employment prior to retirement, the participant may elect to receive a payout beginning the year after termination in the amount of his or her account balance as of the termination date either in a lump sum or in annual installments over a period of five years. Any participant who suffers from a continued disability will be entitled to the benefits of plan participation unless and until the committee administering the plan determines that the participant has been terminated for purposes of continued participation in the plan. Upon any such determination, the disabled participant is paid out as though the participant had retired. Except in certain limited circumstances, participants' account balances will be paid out in a lump sum (1) upon the occurrence of a change in control, as defined in the plan, or (2) upon any downgrade of the Company's senior debt obligations to less than "investment grade." The deferred amounts will be paid out of the general corporate assets or the assets of the Wisconsin Energy Corporation 2014 Rabbi Trust.

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE IN CONTROL

The tables below reflect the amount of compensation payable to each of our NEOs (other than Mr. Keyes) in the event of termination of each executive's employment. These amounts are in addition to each NEO's aggregate balance in the EDCP at fiscal year-end 2018, as reported in the "Aggregate Balance at Last Fiscal Year-End" column under "Nonqualified Deferred Compensation for Fiscal Year 2018." The amount of compensation payable to each NEO (other than Mr. Keyes) upon voluntary termination, normal retirement, for-cause termination, involuntary termination (by the Company for any reason other than cause, death or disability or by the executive for "good reason"), termination following a "change in control," disability, and death are set forth below. The amounts shown assume that such termination was effective as of December 31, 2018 and include amounts earned through that date, and are estimates of the amounts which would be paid out to the NEOs upon termination. The amounts shown under "Normal Retirement" assume the NEOs were retirement eligible with no reduction of retirement benefits. The amounts shown under "Termination Upon a Change in Control" assume the NEOs terminated employment as of December 31, 2018, which was within 18 months of a change in control of WEC Energy Group. The amounts reported in the row titled "Retirement Plans" in each table below are not in addition to the amounts reflected under "Pension Benefits at Fiscal Year-End 2018." The actual amounts to be paid out can only be determined at the time of an officer's termination of employment.

Payments Made Upon Voluntary Termination or Termination for Cause, Death or Disability

In the event a NEO voluntarily terminates employment or is terminated for cause, death, or disability, the officer will receive:

- accrued but unpaid base salary and, for termination by death or disability, prorated annual incentive compensation;
- 401(k) plan and EDCP account balances;
- the WEC Energy Group Plan cash balance;
- in the case of death or disability, full vesting in all outstanding stock options, restricted stock, and performance units (otherwise, the ability to exercise already vested options within three months of termination) as well as vesting in the SERP and ILAs; and
- if voluntary termination occurs after age 60, such termination is treated as a normal retirement.

NEOs are also entitled to the value of unused vacation days, if any, and for termination by death, benefits payable under the officer life insurance benefit if the NEO participates in such benefit.

On September 6, 2018, Mr. Keyes submitted his resignation from all officer positions with the Company and its subsidiaries, including as Executive Vice President of the Company, effective September 14, 2018. In order to transition his responsibilities to other executives of the Company, he remained an employee until January 4, 2019. In connection with such termination, Mr. Keyes received accrued and unpaid base salary, 401(k) plan and EDCP balances, his WEC Energy Group Plan cash balance, and the value of unused vacation days. As a result, we have not included a table reflecting potential termination payments to Mr. Keyes under other circumstances.

Payments Made Upon Normal Retirement

In the event of the retirement of a NEO, the officer will receive:

- accrued but unpaid base salary and prorated annual incentive compensation;
- full vesting in all outstanding stock options and a prorated amount of performance units;
- full vesting in all retirement plans, including the WEC Energy Group Plan, SERP, and ILAs; and
- 401(k) plan and EDCP account balances.
- NEOs are also entitled to the value of unused vacation days, if any.

Payments Made Under Employment Agreements Upon a Change in Control, Involuntary Termination, or Termination for Good Reason

WEC Energy Group entered into a written employment agreement with Mr. Fletcher effective October 31, 2011. The Compensation Committee did not amend or otherwise modify Mr. Fletcher's employment agreement in any way in connection with his appointment as President and CEO. Pursuant to the terms of this agreement, Mr. Fletcher is entitled to severance benefits if his employment is terminated (1) by the Company for any reason other than cause, death, or disability, or (2) by Mr. Fletcher for good reason. Upon termination, Mr. Fletcher's agreement provides for (1) a lump sum payment equal to 2.99 times his annual base salary for the fiscal year in which termination occurs, and (2) health, life and other welfare benefits (excluding disability benefits) for a period of three years following termination.

Generally, pursuant to Mr. Fletcher's ILA, good reason means:

(1) a material reduction in the executive's base compensation;

(2) a material change in the geographic location at which the executive must perform services; or

(3) a material breach of the agreement by the Company.

WEC Energy Group also entered into a written employment agreement with Mr. Leverett, dated as of December 28, 2008, which provides for certain severance benefits if his employment is terminated, among other ways:

- in anticipation of or following a change in control by the Company for any reason, other than cause, death, or disability;
- by Mr. Leverett for good reason in anticipation of or following a change in control; or
- by Mr. Leverett within six months after completing one year of service following a change in control.

Upon termination of his employment in connection with a change in control, Mr. Leverett's agreement provides for:

- a lump sum severance payment equal to three times the sum of Mr. Leverett's highest annual base salary in effect for the three years preceding his termination and highest bonus amount;
- three years continuation of health and certain other welfare benefit coverage and eligibility for retiree health coverage thereafter;
- a payment equal to the value of three additional years of participation in the applicable qualified and non-qualified retirement plans based upon the higher of (1) the annual base salary in effect at the time of termination, and (2) any salary in effect during the 180 day period preceding termination, plus the highest bonus amount;
- a payment equal to the value of three additional years of Company match in the 401(k) plan and EDCP;
- full vesting in all outstanding stock options, restricted stock, and other equity awards;
- 401(k) and EDCP account balances;
- certain financial planning services and other benefits; and
- a "gross up" payment should any payments under the agreement trigger federal excise taxes under the "parachute payment" provisions of the tax law.

The highest bonus amount would be calculated as the larger of (1) the current target bonus for the fiscal year in which employment termination occurs, or (2) the highest bonus paid in any of the last three fiscal years of the Company prior to termination or the change in control. The agreement contains a one-year non-compete provision applicable on termination of employment.

Generally, pursuant to Mr. Leverett's agreement, a change in control is deemed to occur:

(1) if any person or group acquires WEC Energy Group common stock that constitutes more than 50% of the total fair market value or total voting power of WEC Energy Group;

(2) if any person or group acquires (or has acquired during the 12-month period ending on the date of the most recent acquisition by such person or group) WEC Energy Group common stock that constitutes 30% or more of the total voting power of WEC Energy Group;

(3) if a majority of the members of WEC Energy Group's Board is replaced during any 12-month period by directors whose appointment or election is not endorsed by a majority of WEC Energy Group's Board before the date of appointment or election; or

(4) if any person or group acquires (or has acquired during the 12-month period ending on the date of the most recent acquisition by such person or group) assets from WEC Energy Group that have a total gross fair market value equal to or

more than 40% of the total gross value of all the assets of WEC Energy Group immediately before such acquisition or acquisitions, unless the assets are transferred to:

- an entity that is controlled by the stockholders of the transferring corporation;
- a stockholder of WEC Energy Group in exchange for or with respect to its stock;
- an entity of which WEC Energy Group owns, directly or indirectly, 50% or more of its total value or voting power; or
- a person or group (or an entity of which such person or group owns, directly or indirectly, 50% or more of our total value or voting power) that owns, directly or indirectly, 50% or more of the total value or voting power of WEC Energy Group.

Under the terms of his agreement, effective March 2020, Mr. Leverett will no longer be entitled to these change in control benefits.

The employment agreements Messrs. Klappa and Kuester entered into upon commencement of their employment with WEC Energy Group in 2003 terminated upon their retirements in May 2016 and January 2013, respectively.

Pursuant to the terms of the SPP and ILAs, retirement benefits are paid to the NEOs upon termination of employment within 18 months of a change in control. Participants appointed by the Company, including the NEOs, are also eligible to receive a supplemental disability benefit pursuant to the terms of the WEC Energy Group Supplemental Long Term Disability Plan, in an amount equal to the difference between the actual amount of the benefit payable under the long term disability plan applicable to all employees and what such disability benefit would have been if calculated without regard to any limitation imposed by the broad-based plan on annual compensation recognized thereunder. Mr. Leverett is currently receiving benefits under this plan.

Payments under the Severance Pay Plan

Messrs. Klappa, Lauber, and Kuester, and Ms. Kelsey, have not entered into any agreement that currently provides for severance benefits upon a change in control or otherwise. These officers are eligible to participate in the Company's Severance Pay Plan, in which all management employees are eligible to participate. In the event a participant is involuntarily terminated, other than for cause, death, disability, retirement, or resignation, the participant is entitled to receive severance pay in an amount equal to the sum of: (1) 4% of the participant's annual base salary and target bonus, plus (2) 4% of the participant's annual base salary and target bonus multiplied by his or her completed years of service with the Company. The maximum amount of severance pay that can be received under the plan is twelve months of a participant's annual base salary and target bonus.

Potential Payments to Named Executive Officers Upon Termination or Change in Control of the Company

The following tables show the potential payments upon termination or a change in control of the Company for:

Executive Benefits and Payments Upon Separation	Voluntary Termination ($)	Normal Retirement ($)	For Cause Termination ($)	Involuntary Termination ($)	Termination Upon Change in Control ($)	Disability ($)	Death ($)
Gale E. Klappa							
Cash Severance	—	—	—	1,881,000	1,881,000	—	—
Additional Pension Credited Service	—	—	—	—	—	—	—
Additional 401(k) and EDCP Match	—	—	—	—	—	—	—
Long-Term Incentive Compensation:							
Performance Units	—	—	—	—	—	—	—
Restricted Stock	—	—	—	—	3,948,374	3,948,374	3,948,374
Options	—	376,290	—	—	376,290	376,290	376,290
Benefits & Perquisites:							
Retirement Plans	26,478,394	26,478,394	26,478,394	26,478,394	26,478,394	26,478,394	
Health and Welfare Benefits	—	—	—	9,497	9,497	—	—
Excise Tax Gross-Up	—	—	—	—	—	—	—
Financial Planning	—	—	—	—	—	—	—
Outplacement	—	—	—	—	—	—	—
Death Benefit	—	—	—	—	—	—	—
Total	26,478,394	26,854,684	26,478,394	28,368,891	32,693,555	30,803,058	4,324,664
Scott J. Lauber							
Cash Severance	—	—	—	1,059,920	1,059,920	—	—
Additional Pension Credited Service	—	—	—	—	—	—	—
Additional 401(k) and EDCP Match	—	—	—	—	—	—	—
Long-Term Incentive Compensation:							
Performance Units	—	620,085	—	—	1,308,806	1,308,806	1,308,806
Restricted Stock	—	—	—	—	261,803	261,803	261,803
Options	—	398,831	—	—	398,831	398,831	398,831
Benefits & Perquisites:							
Retirement Plans	670,873	670,873	670,873	670,873	670,873	670,873	628,135
Health and Welfare Benefits	—	—	—	9,497	9,497	—	—
Excise Tax Gross-Up	—	—	—	—	—	—	—
Financial Planning	—	—	—	—	—	—	—
Outplacement	—	—	—	—	—	—	—
Death Benefit	—	—	—	—	—	—	—
Total	670,873	1,689,789	670,873	1,740,290	3,709,730	2,640,313	2,597,575
J. Kevin Fletcher							
Cash Severance	—	—	—	2,093,000	2,093,000	—	—
Additional Pension Credited Service	—	—	—	—	—	—	—
Additional 401(k) and EDCP Match	—	—	—	—	—	—	—
Long-Term Incentive Compensation:							
Performance Units	—	521,459	—	—	1,011,889	1,011,889	1,011,889
Restricted Stock	—	—	—	—	210,550	210,550	210,550
Options	—	503,570	—	—	503,570	503,570	503,570
Benefits & Perquisites:							
Retirement Plans	5,776,545	5,776,545	5,776,545	5,776,545	5,776,545	5,776,545	3,465,042
Health and Welfare Benefits	—	—	—	56,984	56,984	—	—
Excise Tax Gross-Up	—	—	—	—	—	—	—
Financial Planning	—	—	—	—	—	—	—
Outplacement	—	—	—	—	—	—	—
Death Benefit	—	—	—	—	—	—	2,100,000
Total	5,776,545	6,801,574	5,776,545	7,926,529	9,652,538	7,502,554	7,291,051

Executive Benefits and Payments Upon Separation	Voluntary Termination ($)	Normal Retirement ($)	For Cause Termination ($)	Involuntary Termination ($)	Termination Upon Change in Control ($)	Disability ($)	Death ($)
Frederick D. Kuester							
Cash Severance	—	—	—	538,965	538,965	—	—
Additional Pension Credited Service	—	—	—	—	—	—	—
Additional 401(k) and EDCP Match	—	—	—	—	—	—	—
Long-Term Incentive Compensation:							
Performance Units	—	—	—	—	—	—	—
Restricted Stock	—	—	—	—	1,704,419	1,704,419	1,704,419
Options	—	162,428	—	—	162,428	162,428	162,428
Benefits & Perquisites:							
Retirement Plans	10,136,294	10,136,294	10,136,294	10,136,294	10,136,294	10,136,294	5,120,424
Health and Welfare Benefits	—	—	—	9,497	9,497	—	—
Excise Tax Gross-Up	—	—	—	—	—	—	—
Financial Planning	—	—	—	—	—	—	—
Outplacement	—	—	—	—	—	—	—
Death Benefit	—	—	—	—	—	—	—
Total	10,136,294	10,298,722	10,136,294	10,684,756	12,551,603	12,003,141	6,987,271
Margaret C. Kelsey							
Cash Severance	—	—	—	70,040	70,040	—	—
Additional Pension Credited Service	—	—	—	—	—	—	—
Additional 401(k) and EDCP Match	—	—	—	—	—	—	—
Long-Term Incentive Compensation:							
Performance Units	—	175,297	—	—	525,822	525,822	525,822
Restricted Stock	—	—	—	—	117,396	117,396	117,396
Options	—	59,643	—	—	59,643	59,643	59,643
Benefits & Perquisites:							
Retirement Plans	—	—	—	—	—	—	—
Health and Welfare Benefits	—	—	—	9,497	9,497	—	—
Excise Tax Gross-Up	—	—	—	—	—	—	—
Financial Planning	—	—	—	—	—	—	—
Outplacement	—	—	—	—	—	—	—
Death Benefit	—	—	—	—	—	—	1,545,000
Total	—	234,940	—	79,537	782,398	702,861	2,247,861
Allen L. Leverett							
Cash Severance	—	—	—	—	12,458,256	—	—
Additional Pension Credited Service	—	—	—	—	6,344,721	—	—
Additional 401(k) and EDCP Match	—	—	—	—	498,330	—	—
Long-Term Incentive Compensation:							
Performance Units	—	3,926,903	—	—	7,620,678	7,620,678	7,620,678
Restricted Stock	—	—	—	—	1,610,156	1,610,156	1,610,156
Options	—	3,802,070	—	—	3,802,070	3,802,070	3,802,070
Benefits & Perquisites:							
Retirement Plans	—	17,220,509	—	—	11,604,163	17,220,509	6,623,909
Health and Welfare Benefits	—	—	—	—	70,485	—	—
Excise Tax Gross-Up	—	—	—	—	16,997,105	—	—
Financial Planning	—	—	—	—	54,000	—	—
Outplacement	—	—	—	—	30,000	—	—
Death Benefit	—	—	—	—	—	—	—
Total	—	24,949,482	—	—	61,089,964	30,253,413	19,656,813

PAY RATIO DISCLOSURE

The primary objective of our executive compensation program is to provide a competitive, performance-based plan that enables the Company to attract and retain key individuals and to reward them for achieving both the Company's short-term and long-term goals without creating an incentive for our NEOs to take excessive risks. In line with this objective, the Company's general pay practice for all management employees is to target the median pay for each individual's position at comparably sized companies.

For 2018, the annual total compensation of Mr. Klappa, our principal executive officer serving in that position on December 31, 2018, of $9,862,993, as shown in the Summary Compensation Table above ("CEO Compensation"), was approximately 91 times the annual total compensation of the median employee of $107,894.

We identified the median employee as of October 7, 2017, using total wages and earnings paid during the rolling 12-month period ended October 7, 2017, as reflected in our internal payroll records (including, without limitation, base salary, wages plus overtime, and annual cash incentive payments, as applicable), for all individuals, excluding Mr. Leverett (then CEO of the Company), who were employed by us or any of our consolidated subsidiaries on October 7, 2017 (whether employed on a full-time, part-time, seasonal or temporary basis and including union and non-union employees). After identifying the median employee, we calculated annual total compensation for such employee using the same methodology we use for our CEO Compensation, which includes annual salary, bonus, change in pension value and 401(k) matching by the Company. As defined under the pay ratio disclosure rules, the median employee remained the same since there has been no change in the Company's employee population or employee compensation that would significantly affect the pay ratio.

To provide further context to our pay practices, due to the complexity of the work associated with operating public utilities, our workforce tends to be more highly skilled than workforces at companies in other industries. Additionally, our employees often work for the Company for long periods of time; our average employee tenure is 15 years.

RISK ANALYSIS OF COMPENSATION POLICIES AND PRACTICES

As part of its process to determine the 2018 compensation of WEC Energy Group's NEOs, the Compensation Committee analyzed whether WEC Energy Group's compensation program taken as a whole creates risks that are reasonably likely to have a material adverse effect on the Company. The Compensation Committee concluded it does not. This analysis applies generally to the compensation program for WEC Energy Group's employees since all management employees (both officers and non-officers) above a certain level are provided with substantially the same mix of compensation as the NEOs. The compensation package provided to employees below this level is not applicable to this analysis as such compensation package does not provide sufficient incentive to take risks that could materially affect the Company.

There is no objective way to measure risk resulting from a corporation's compensation program; therefore, this analysis is subjective in nature. We believe that the only elements of WEC Energy Group's compensation program that could incentivize risk-taking by our employees, and therefore have a reasonable likelihood of materially adversely affecting the Company, are the annual cash incentive compensation and the long-term incentive compensation, the payout of which is dependent upon the achievement of certain performance levels by the Company. Based upon the value of each of these elements to the overall compensation mix and the relative value each has to the other, we believe the Company's compensation program is appropriately balanced. We believe that the mix of short- and long-term awards minimizes risks that may be taken, as any risks taken for short-term gains could ultimately jeopardize the Company's ability to meet the long-term performance objectives. Given the current balance of compensation elements, we do not believe WEC Energy Group's compensation program incentivizes unreasonable risk-taking by management.

The Compensation Committee's stock ownership guidelines require officers who participate in the long-term incentive compensation program to hold an amount of Company common stock and other equity-related Company securities that varies depending upon such officers' level. The guidelines require the Company's executive officers to hold common stock and other equity-related securities of the Company having a minimum fair market value ranging from 250% to 600% of base salary. The Compensation Committee believes these stock ownership guidelines further discourage unreasonable risk taking by Company officers.

As part of this analysis, we also considered the nature of WEC Energy Group's business as a public utility holding company and the fact that substantially all of the Company's earnings and other financial results are generated by, or relate to, regulated public utilities. The highly regulated nature of WEC Energy Group's business, including limits on the amount of profit the Company's public utility subsidiaries (and therefore, WEC Energy Group) may earn, significantly reduces any incentive to engage in conduct that would be reasonably likely to have a material adverse effect on the Company.

PROPOSAL 3: RATIFICATION OF DELOITTE & TOUCHE LLP AS INDEPENDENT AUDITORS FOR 2019

The Audit and Oversight Committee of the Board of Directors has sole authority to select, evaluate, and, where appropriate, terminate and replace the independent auditors. The Audit and Oversight Committee has appointed Deloitte & Touche LLP as the Company's independent auditors for the fiscal year ending December 31, 2019. The Audit and Oversight Committee believes that stockholder ratification of this matter is important considering the critical role the independent auditors play in maintaining the integrity of the Company's financial statements. If stockholders do not ratify the selection of Deloitte & Touche LLP, the Audit and Oversight Committee will reconsider the selection.

Deloitte & Touche LLP has served as the independent auditors for the Company for the last 17 fiscal years beginning with the fiscal year ended December 31, 2002. The members of the Audit and Oversight Committee and the other members of the Board believe that the continued retention of Deloitte & Touche LLP to serve as the Company's independent external auditor is in the best interests of the Company and our stockholders.

Ratification of Deloitte & Touche LLP as the Company's independent auditors requires the affirmative vote of a majority of the votes cast in person or by proxy at the Meeting. Presuming a quorum is present, shares not voted, whether by abstention or otherwise, have no effect on the outcome of this matter.

Representatives of Deloitte & Touche LLP are expected to be present at the Meeting. They will have an opportunity to make a statement if they so desire and are expected to respond to appropriate questions that may be directed to them. Information concerning Deloitte & Touche LLP can be found in the following pages.

The Board of Directors recommends that you vote "FOR" the ratification of Deloitte & Touche LLP as independent auditors for 2019.

INDEPENDENT AUDITORS' FEES AND SERVICES

Pre-Approval Policy. The Audit and Oversight Committee has a formal policy delineating its responsibilities for reviewing and approving, in advance, all audit, audit-related, tax, and other services of the independent auditors. As such, the Audit and Oversight Committee is responsible for the audit fee negotiations associated with the Company's retention of independent auditors.

The Audit and Oversight Committee is committed to ensuring the independence of the auditors, both in appearance as well as in fact. In order to assure continuing auditor independence, the Audit and Oversight Committee periodically considers whether there should be a regular rotation of the independent external audit firm. In addition, the Audit and Oversight Committee is directly involved in the selection of Deloitte & Touche LLP's lead engagement partner.

Under the pre-approval policy, before engagement of the independent auditors for the next year's audit, the independent auditors will submit (1) a description of all services anticipated to be rendered, as well as an estimate of the fees for each of the services, for the Audit and Oversight Committee to approve, and (2) written confirmation that the performance of any non-audit services is permissible and will not impact the firm's independence. Annual pre-approval will be deemed effective for a period of twelve months from the date of pre-approval, unless the Audit and Oversight Committee specifically provides for a different period. A fee level will be established for all permissible, pre-approved non-audit services. Any additional audit service, audit-related service, tax service, and other service must also be pre-approved.

The Audit and Oversight Committee delegated pre-approval authority to the Committee's Chair. The Audit and Oversight Committee Chair is required to report any pre-approval decisions at the next scheduled Audit and Oversight Committee meeting. Under the pre-approval policy, the Audit and Oversight Committee may not delegate to management its responsibilities to pre-approve services performed by the independent auditors.

Under the pre-approval policy, prohibited non-audit services are services prohibited by the Securities and Exchange Commission or by the Public Company Accounting Oversight Board (United States) to be performed by the Company's independent auditors. These services include: bookkeeping or other services related to the accounting records or financial statements of the Company; financial information systems design and implementation; appraisal or valuation services, fairness opinions or contribution-in-kind reports; actuarial services; internal audit outsourcing services; management functions or human resources; broker-dealer, investment advisor or investment banking services; legal services and expert services unrelated to the audit; services provided for a contingent fee or commission; and services related to planning, marketing or opining in favor of the tax treatment of a confidential transaction or an aggressive tax position transaction that was initially recommended, directly or indirectly, by the independent auditors. In addition, the Audit and Oversight Committee has determined that the independent auditors may not provide any services, including personal financial counseling and tax services, to any officer or other employee of the Company who serves in a financial reporting oversight role or to the chair of the Audit and Oversight Committee or to an immediate family member of these individuals, including spouses, spousal equivalents, and dependents.

Fee Table. The following table shows the fees, all of which were approved by the Audit and Oversight Committee, for professional audit services provided by Deloitte & Touche LLP for the audit of the annual financial statements of the Company and its subsidiaries for fiscal years 2018 and 2017, and fees for other services rendered during those periods. No fees were paid to Deloitte & Touche LLP pursuant to the "de minimus" exception to the pre-approval policy permitted under the Securities Exchange Act of 1934, as amended.

	2018	2017
Audit Fees [1]	$ 5,531,450	$ 5,064,125
Audit-Related Fees [2]	—	—
Tax Fees [3]	67,226	20,000
All Other Fees [4]	8,495	7,095
Total	$ 5,607,171	$ 5,091,220

(1) Audit Fees consist of fees for professional services rendered in connection with: (1) the audits of the annual financial statements of the Company and its subsidiaries, (2) the audits of the effectiveness of internal control over financial reporting, and (3) other non-recurring audit work. This category also includes reviews of financial statements included in Form 10-Q filings of the Company and its subsidiaries and services provided in connection with statutory and regulatory filings or engagements.

(2) Audit-Related Fees consist of fees for professional services that are reasonably related to the performance of the audit or review of the Company's financial statements and are not reported under "Audit Fees." No such services were received from Deloitte & Touche LLP in 2018 or 2017.

(3) Tax Fees consist of fees for professional services rendered with respect to federal and state tax compliance and tax advice. This can include preparation of tax returns, claims for refunds, payment planning, and tax law interpretation.

(4) All Other Fees consist of costs for certain employees to attend accounting/tax seminars hosted by Deloitte & Touche LLP plus the subscription cost for the use of a Deloitte & Touche LLP accounting research tool.

AUDIT AND OVERSIGHT COMMITTEE REPORT

The Audit and Oversight Committee, which is comprised solely of independent directors, oversees the integrity of the financial reporting process on behalf of the Board of WEC Energy Group, Inc. In addition, the Audit and Oversight Committee oversees compliance with legal and regulatory requirements. The Audit and Oversight Committee operates under a written charter approved by the Board, which can be found in the "Governance" section of the Company's Website at wecenergygroup.com.

The Audit and Oversight Committee is also directly responsible for the appointment, compensation, retention, and oversight of the Company's independent auditors, as well as the oversight of the Company's internal audit function.

In order to assure continuing auditor independence, the Audit and Oversight Committee periodically considers whether there should be a regular rotation of the independent external audit firm. For 2019, the Audit and Oversight Committee has appointed Deloitte & Touche LLP to remain as the Company's independent auditors, subject to stockholder ratification. The members of the Audit and Oversight Committee and other members of the Board believe that the continued retention of Deloitte & Touche LLP to serve as the Company's independent external auditor is in the best interests of the Company and its stockholders.

The Audit and Oversight Committee is directly involved in the selection of Deloitte & Touche LLP's lead engagement partner in conjunction with a mandated rotation policy and is also responsible for audit fee negotiations with Deloitte & Touche LLP.

Management is responsible for the Company's financial reporting process, the preparation of consolidated financial statements in accordance with generally accepted accounting principles, and the system of internal controls and procedures designed to provide reasonable assurance regarding compliance with accounting standards and applicable laws and regulations. The Company's independent auditors are responsible for performing an independent audit of the Company's consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States) (the "PCAOB") and issuing a report thereon.

The Audit and Oversight Committee held six meetings during 2018. Meetings are designed to facilitate and encourage open communication among the members of the Audit and Oversight Committee, management, the internal auditors, and the Company's independent auditors, Deloitte & Touche LLP. During these meetings, we reviewed and discussed with management, among other items, the Company's unaudited quarterly and audited annual financial statements and the system of internal controls designed to provide reasonable assurance regarding compliance with accounting standards and applicable laws.

We have reviewed and discussed with management and the Company's independent auditors the Company's audited consolidated financial statements and related footnotes for the fiscal year ended December 31, 2018, and the independent auditor's report on those financial statements. Management represented to us that the Company's financial statements were prepared in accordance with generally accepted accounting principles. Deloitte & Touche LLP presented the matters required to be discussed with the Audit and Oversight Committee by PCAOB Auditing Standard No. 1301, *Communications with Audit Committees*. This review included a discussion with management and the independent auditors about the quality of the Company's accounting principles, the reasonableness of significant estimates and judgments, and the disclosures in the Company's financial statements, as well as the disclosures relating to critical accounting policies.

In addition, we received the written disclosures and correspondence relative to the auditors' independence from Deloitte & Touche LLP, as required by applicable requirements of the PCAOB regarding Deloitte & Touche LLP's communications with the Audit and Oversight Committee concerning independence. The Audit and Oversight Committee discussed with Deloitte & Touche LLP its independence and also considered the compatibility of non-audit services provided by Deloitte & Touche LLP with maintaining its independence.

Based on these reviews and discussions, the Audit and Oversight Committee recommended to the Board that the audited financial statements be included in WEC Energy Group's Annual Report on Form 10-K for the fiscal year ended December 31, 2018 and filed with the Securities and Exchange Commission.

Respectfully submitted to WEC Energy Group stockholders by the Audit and Oversight Committee of the Board.

The Audit and Oversight Committee

Thomas J. Fischer, Committee Chair
John F. Bergstrom
Barbara L. Bowles
Patricia W. Chadwick
Danny L. Cunningham
Henry W. Knueppel

WEC ENERGY GROUP COMMON STOCK OWNERSHIP

Beneficial Ownership. The following table lists the beneficial ownership of WEC Energy Group common stock of each director, director nominee, NEO, and of all of the directors and executive officers as a group as of January 31, 2019. In general, "beneficial ownership" includes those shares as to which the indicated persons have voting power or investment power and stock options that are exercisable currently or within 60 days of January 31, 2019. Included are shares owned by each individual's spouse, minor children, or any other relative sharing the same residence, as well as shares held in a fiduciary capacity or held in WEC Energy Group's Stock Plus Investment Plan and WEC Energy Group's 401(k) plans. None of these persons beneficially owns more than 1% of the outstanding common stock.

	Shares Beneficially Owned [1]		
Name	Shares Owned [2] [3] [4]	Option Shares Exercisable Within 60 Days	Total
John F. Bergstrom	13,499	—	13,499
Barbara L. Bowles	22,301	—	22,301
William J. Brodsky	43,031	—	43,031
Albert J. Budney, Jr.	6,154	—	6,154
Patricia W. Chadwick	23,403	—	23,403
Curt S. Culver	1,981	—	1,981
Danny L. Cunningham	4,156	—	4,156
William M. Farrow III	4,095	—	4,095
Thomas J. Fischer	41,176	—	41,176
J. Kevin Fletcher	12,395	27,105	39,500
Margaret C. Kelsey	3,926	—	3,926
J. Patrick Keyes	18,998	—	18,998
Gale E. Klappa	204,870	849,685	1,054,555
Henry W. Knueppel	18,391	—	18,391
Frederick D. Kuester	62,599	—	62,599
Scott J. Lauber	19,759	31,620	51,379
Allen L. Leverett	82,502	604,075	686,577
Ulice Payne, Jr.	29,764	—	29,764
Mary Ellen Stanek	4,582	—	4,582
All directors and executive officers as a group (25 persons)	664,865 [5]	1,700,345	2,365,210 [6]

(1) Information on beneficially owned shares is based on data furnished by the specified persons and is determined in accordance with Rule 13d-3 under the Securities Exchange Act of 1934, as amended, as required for purposes of this proxy statement. It is not necessarily to be construed as an admission of beneficial ownership for other purposes.

(2) Certain directors, NEOs, and other executive officers also hold share units in the WEC Energy Group phantom common stock account under WEC Energy Group's deferred compensation plans as indicated: Mr. Bergstrom (72,527), Ms. Bowles (1,503), Mr. Budney (7,118), Mr. Culver (101,447), Mr. Cunningham (1,461), Mr. Fischer (7,593), Ms. Kelsey (3,083), Mr. Keyes (1,148), Mr. Lauber (1,223), Mr. Leverett (80), Mr. Payne (2,114), Ms. Stanek (25,665), and all directors and executive officers as a group (258,523). Share units are intended to reflect the performance of WEC Energy Group common stock and are payable in cash. While these units do not represent a right to acquire WEC Energy Group common stock, have no voting rights, and are not included in the number of shares reflected in the "Shares Owned" column in the table above, the Company listed them in this footnote because they represent an additional economic interest of the directors, NEOs, and other executive officers that is tied to the performance of WEC Energy Group common stock.

(3) Each individual has sole voting and investment power as to all shares listed for such individual, except the following individuals have shared voting and/or investment power (included in the table above) as indicated: Mr. Bergstrom (6,000), Mr. Brodsky (41,050), Mr. Budney (902), Mr. Fischer (37,195), Mr. Klappa (5,000), Mr. Knueppel (16,410), Mr. Leverett (66,511), Ms. Stanek (2,601), and all directors and executive officers as a group (175,669).

(4) The directors and executive officers hold shares of restricted stock (included in the table above) over which the holders have sole voting but no investment power: Mr. Bergstrom (1,981), Ms. Bowles (1,981), Mr. Brodsky (1,981), Mr. Budney (1,981), Ms. Chadwick (1,981), Mr. Culver (1,981), Mr. Cunningham (1,981), Mr. Farrow (1,981), Mr. Fischer (1,981), Mr. Fletcher (5,469), Ms. Kelsey (2,887), Mr. Klappa (18,565), Mr. Knueppel (1,981), Mr. Kuester (48,586), Mr. Lauber (4,864), Mr. Leverett (12,817), Mr. Payne (1,981), Ms. Stanek (1,981), and all directors and executive officers as a group (126,739).

(5) None of the shares beneficially owned by the directors, NEOs, or all directors and executive officers as a group are pledged as security.

(6) Represents approximately 0.75% of total WEC Energy Group common stock outstanding on January 31, 2019.

Owners of More than 5%. The following table shows stockholders who reported beneficial ownership of more than 5% of WEC Energy Group common stock, based on the information they have reported. This information is based upon Schedule 13G filed with the SEC and reflects stock holdings as of December 31, 2018. These holdings have not been otherwise adjusted for stock activity that may have occurred since December 31, 2018, if any.

Name and Address [1]	Voting Authority		Dispositive Authority		Total Shares Beneficially Owned	Percent of WEC Common Stock
	Sole	Shared	Sole	Shared		
The Vanguard Group, Inc. 100 Vanguard Blvd. Malvern, PA 19355	423,111	217,737	35,123,405	579,385	35,702,790	11.31%
BlackRock, Inc. 55 East 52nd Street New York, NY 10055	26,244,500	—	29,050,912	—	29,050,912	9.20%
State Street Corporation One Lincoln Street Boston, MA 02111	—	14,433,070	—	16,105,068	16,112,281	5.10%

(1) Filed on behalf of itself and certain of its subsidiaries.

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Securities Exchange Act of 1934, as amended, requires the Company's executive officers, directors, and persons owning more than 10% of WEC Energy Group's common stock to file reports of ownership and changes in ownership of equity and derivative securities of WEC Energy Group with the SEC and the New York Stock Exchange. Specific due dates for those reports have been established by the SEC, and the Company is required to disclose in this proxy statement any failure to file by those dates during the 2018 fiscal year. To the Company's knowledge, based on information provided by the reporting persons, all applicable reporting requirements for fiscal year 2018 were complied with in a timely manner, except that (i) due to administrative error, one acquisition of phantom stock units by each of William Guc, Tom Metcalfe and James Schubilske was reported late; and (ii) due to broker error, one Form 5 was filed for Frederick Kuester to report additional shares of common stock not previously reported on his Form 3 filed January 29, 2018 and to disclose one purchase of shares of common stock that was not previously reported on a Form 4, as required.

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Compensation Committee Interlocks and Insider Participation. None of the persons who served as members of the Compensation Committee during 2018 was an officer or employee of the Company during 2018 or at any time in the past nor had reportable transactions with the Company.

During 2018, none of our executive officers served as a member of the compensation committee or as a director of another entity, one of whose executive officers served on the Compensation Committee or as a director of the Company.

INFORMATION RELATED TO THE ANNUAL MEETING

BUSINESS OF THE ANNUAL MEETING

Proposal 1: Election of Thirteen Directors for Terms Expiring in 2020. The Board recommends a vote **FOR** each of the nominees. The thirteen individuals will be elected as directors if the number of votes cast in person or by proxy at the Meeting favoring such nominee's election exceeds the number of votes cast opposing that nominee's election. Presuming a quorum is present, shares not voted, whether by broker non-vote, abstention, or otherwise, have no effect on the outcome of this matter.

Proposal 2: Advisory Vote to Approve Compensation of the Named Executive Officers, Commonly Referred to as a "Say-on-Pay" Vote. The Board recommends a vote **FOR** this proposal. Approval, on a non-binding, advisory basis, of the compensation of the NEOs requires the affirmative vote of a majority of the votes cast in person or by proxy at the Meeting. Presuming a quorum is present, shares not voted, whether by broker non-vote, abstention, or otherwise, have no effect on the outcome of this matter. Because your vote is advisory, it will not be binding on the Board or the Company. However, the Compensation Committee will review the voting results and take them into consideration.

Proposal 3: Ratification of Deloitte & Touche LLP as Independent Auditors for 2019. The Board recommends a vote **FOR** this proposal. Ratification of the independent auditors requires the affirmative vote of a majority of the votes cast in person or by proxy at the Meeting. Presuming a quorum is present, shares not voted, whether by abstention or otherwise, have no effect on the outcome of this matter.

The Company is not aware of any other matters that will be voted on. If a matter does properly come before the Meeting, the persons named as the proxies in the form of proxy will vote the proxy at their discretion.

VOTING INFORMATION

Who can vote?

Common stockholders as of the close of business on the Record Date, February 21, 2019, can vote. Each outstanding share of WEC Energy Group common stock is entitled to one vote upon each matter presented. A list of stockholders entitled to vote will be available for inspection by stockholders at WEC Energy Group's principal business office, 231 W. Michigan St., Milwaukee, Wisconsin 53203, prior to the Meeting. The list will also be available at the Meeting.

How do I vote?

There are several ways to vote:

- By Internet. The Company encourages you to vote this way.
- By toll-free, touch-tone telephone.
- By completing and mailing your proxy card.
- By written ballot at the Meeting.

If you wish to vote through the Internet or by telephone, please follow the instructions on your Notice Regarding the Availability of Proxy Materials, proxy card, or the information forwarded to you by your bank or broker, as applicable. The Internet and telephone voting facilities will close at 10:59 p.m., Central time, on Wednesday, May 1, 2019.

If you are a participant in WEC Energy Group's Stock Plus Investment Plan ("Stock Plus") or own shares through investments in the WEC Energy Group Common Stock ESOP Fund in any of WEC Energy Group's 401(k) plans, your proxy will serve as voting instructions for your shares held in those plans. The administrator for Stock Plus and the trustee for WEC Energy Group's 401(k) plans will vote your shares as you direct. If a proxy is not returned for shares held in Stock Plus, the administrator will not vote those shares. If a proxy is not returned for shares held in WEC Energy Group's 401(k) plans, the trustee will vote those shares in the same proportion that all shares in the WEC Energy Group Common Stock ESOP Fund in each respective 401(k) plan, for which voting instructions have been received, are voted.

If you are a beneficial owner and your bank or broker holds your shares in its name, they are permitted to vote your shares in the ratification of the independent auditors even if the broker does not receive voting instructions from you. However, for matters considered non-routine, which includes proposals 1 and 2, your broker or other record holder of your shares will not be permitted to vote your shares unless you provide voting instructions. If your shares are held in the name of a broker, bank or other holder of record, you are invited to attend the Meeting, but may not vote at the Meeting unless you bring a legal proxy from your broker, bank, or other holder of record.

What does it mean if I get more than one proxy?

It means your shares are held in more than one stock account. **Please vote all proxies** to ensure all of your shares are counted.

What constitutes a quorum?

As of the February 21, 2019 Record Date, there were 315,450,338 shares of WEC Energy Group common stock outstanding. In order to conduct the Meeting, a majority of the outstanding shares entitled to vote must be represented in person or by proxy. This is known as a "quorum." Abstentions and shares which are the subject of broker non-votes will count toward establishing a quorum.

Can I change my vote?

You may change your vote or revoke your proxy at any time prior to the closing of the polls by any of the following methods:

- Entering a new vote by Internet or phone;
- Returning a later-dated proxy card;
- Voting in person at the Meeting; or
- Notifying WEC Energy Group's Corporate Secretary by written revocation letter.

The Corporate Secretary is Margaret C. Kelsey. Any revocation should be filed with her at WEC Energy Group's principal business office, 231 W. Michigan St., PO Box 1331, Milwaukee, Wisconsin 53201.

Attendance at the Meeting will not, in itself, constitute revocation of a proxy. All shares entitled to vote and represented by properly completed proxies timely received and not revoked will be voted as you direct. If no direction is given in a properly completed proxy, the proxy will be voted as the Board recommends.

Who conducts the proxy solicitation?

The Board is soliciting these proxies. WEC Energy Group will bear the cost of the solicitation of proxies. The Company contemplates that proxies will be solicited principally through the use of the mail, but employees of WEC Energy Group or our subsidiaries may solicit proxies by telephone, personally, or by other communications, without compensation apart from their normal salaries. WEC Energy Group has retained Morrow Sodali LLC to assist in the solicitation of proxies for a fee of $23,000 plus reimbursement of expenses. WEC Energy Group will also reimburse brokers, banks, and other nominees for forwarding proxy materials to beneficial stockholders.

Who will count the votes?

Computershare, which will also serve as Inspector of Election, will tabulate the vote. Computershare is the Company's transfer agent.

Where can I find the voting results from the Meeting?

The Meeting voting results will be published in a Form 8-K, available no later than May 8, 2019, on the Company's website, wecenergygroup.com, under the "Investors" section.

ELECTRONIC ACCESS TO ANNUAL MEETING INFORMATION

Why did I receive a separate Notice Regarding the Availability of Proxy Materials (Notice) instead of printed proxy materials?

Pursuant to rules adopted by the SEC, we are providing access to our proxy materials over the Internet. Accordingly, we began mailing a separate Notice to stockholders on or about March 21, 2019, instead of a full set of our printed proxy materials. The Notice is not a proxy card and cannot be used to vote your shares. However, the Notice includes instructions on how to access our proxy materials online and vote your shares.

You may request a printed set of proxy materials by (1) logging on to www.envisionreports.com/wec and following the applicable instructions, (2) calling 866-641-4276, or (3) sending an email requesting a paper copy of current meeting materials to investorvote@computershare.com with "Proxy Materials WEC Energy Group" in the subject line and your full name and address plus the number located in the shaded bar on the Notice.

If your shares are held by a broker, trustee, bank, or other nominee, please refer to the instructions provided by such record holder on how to access our proxy materials and vote.

What practices may stockholders follow that are friendly to the environment and help reduce printing and postage costs?

Stockholders may wish to participate in the following:

- **View the following documents online at www.envisionreports.com/wec:**
  - Notice of Annual Meeting
  - Proxy Statement
  - 2018 Annual Report
  - Form of Proxy

- **Vote your proxy online or by telephone. Page P-8**

- **Choose to receive future proxy materials and annual reports electronically instead of receiving paper copies.**

  If you are a registered stockholder and received a paper copy of our proxy materials or a paper notice this year, you may elect to receive access to future copies of these documents and other stockholder communications (e.g., investment plan statements, tax documents, and more) electronically by (1) following the instructions when voting by Internet or by telephone, or (2) registering for our eDelivery paperless communication program.

  If your shares are held by a broker, trustee, bank or other nominee, please refer to the instructions provided by such record holder on how to elect to receive access to our future proxy materials and annual reports online.

  By delivering our proxy materials electronically, we can provide you with the information you need quickly, efficiently, and in a more cost-effective manner.

- **Choose our eDelivery paperless communication program for all your stockholder needs.**

  Electronic distribution gives stockholders faster delivery of account documents and saves the Company and our stockholders the cost of printing and mailing these materials. eDelivery also provides you with fast and secure 24/7 online access to proxy materials, investment plan statements, tax documents, and more. You may access your registered stockholder account and sign up for eDelivery at www.computershare.com/investor.

- **Sign up for Householding.**

  “Householding” is a delivery method that allows for only one paper copy of the Annual Report and Proxy Statement to be delivered to stockholders who reside at the same address.

  If you are a registered stockholder and received multiple paper copies of the Annual Report and Proxy Statement, you may wish to contact the Company’s transfer agent, Computershare, at 800-558-9663, to request householding, or you may provide written instructions to WEC Energy Group, c/o Computershare, PO 505000, Louisville, KY 40233-5000. If you wish to receive separate copies of the Annual Report and Proxy Statement now or in the future, or to discontinue householding entirely, you may contact the Company’s transfer agent using the contact information provided above. Upon request, the Company will promptly send a separate copy of the document. Whether or not a stockholder is householding, each stockholder will continue to receive a proxy card. If your shares are held through a bank, broker, or other holder of record, you may request householding by contacting the holder of record.

ANNUAL MEETING ATTENDANCE

How do I pre-register to attend the Annual Meeting?

The Meeting is open to all stockholders of WEC Energy Group. **You must pre-register to reserve an admission ticket** and then present your government-issued photo identification at the door in order to attend.

If you would like to attend, please contact Stockholder Services by email at wec.stockholder-services.contact@wecenergygroup.com or by telephone at 800-881-5882 to reserve an admission ticket. If you hold your shares in “street name” through an intermediary, such as a bank, brokerage firm, or other nominee, and you would like to attend the Meeting, please send us a written request for an admission ticket either by regular mail, fax, or email, along with proof of share ownership, such as a bank, or brokerage firm account statement, a copy of the voting instruction card provided by your broker, or a letter from the broker, trustee, bank or nominee holding your shares to: Stockholder Services, 231 W. Michigan Street, PO Box 1331, Milwaukee, Wisconsin 53201; fax: 414-221-3888; or email: wec.stockholder-services.contact@wecenergygroup.com.

Requests to reserve admission tickets will be processed in the order in which they are received and must be received no later than five business days before the Meeting, or Thursday, April 25, 2019. If we cannot confirm you are a registered stockholder or beneficial owner, we will contact you for further information.

Admission tickets will be available for pick-up at the Meeting. All Meeting attendees will be asked to present a government-issued photo identification card before receiving a ticket. We will then verify your name against our stockholder list. If you own shares in the name of your broker, bank, or other nominee ("street name"), you should bring your proof of share ownership with you to the Meeting. If we cannot verify that you are a stockholder, you may not be admitted to the Meeting.

The Meeting will begin promptly at 10:00 a.m., Central time. Check-in will begin at 9:00 a.m. Please allow ample time for check-in procedures.

What attendance guidelines apply to the Annual Meeting?

If you plan to attend the Meeting, please review the following attendance guidelines:

- **You must pre-register and reserve an admission ticket in order to attend.**
- You will be asked to check in upon entry into the R. John Buuck Field House and present government-issued photo identification, such as a driver's license, state identification card, or passport. We will verify your name against our stockholder list and will then provide you with an admission ticket.
- The Company reserves the right to inspect all items, including handbags and briefcases, prior to admittance.
- The business of the Meeting will follow as set forth in the agenda, which you will receive upon check-in.
- Stockholder questions and comments related to the business of the Company will be addressed only during the question and answer portion of the agenda. If you wish to speak, please go to the nearest microphone and wait to be recognized by the Chairman. State your name before asking your question. Questions from the floor are limited to three minutes to provide an opportunity for as many stockholders as possible.
- The use of cameras, recording devices, and other electronic devices will not be permitted during the Meeting except by those employed by the Company to provide a record of the proceedings. Please silence all cell phones and other electronic devices.
- No firearms or weapons will be allowed in the Meeting facilities.
- No signs, banners, placards, handouts, and similar materials will be allowed on Meeting premises.

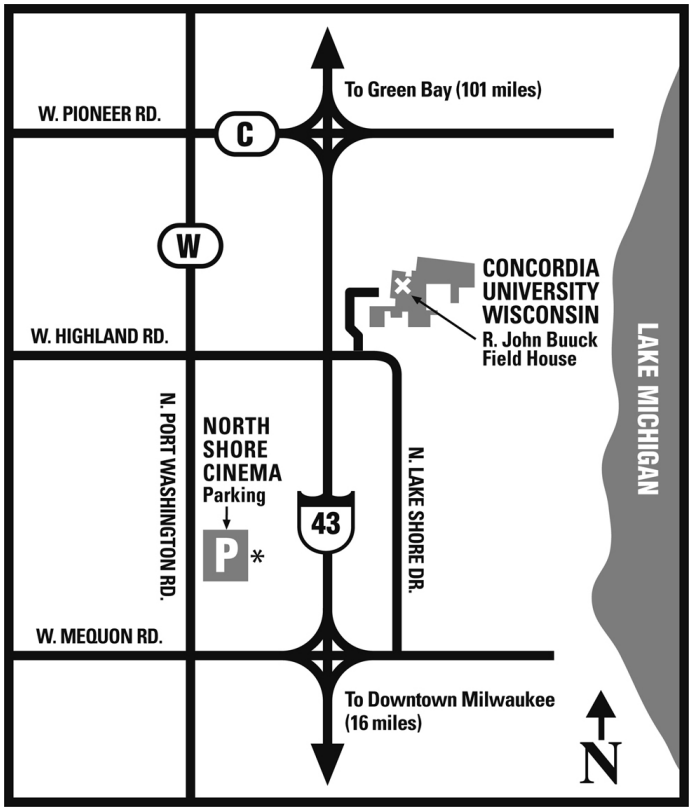
Attendees who fail to comply with these guidelines risk expulsion from the Meeting. In the event of a disruption, the Chairman may immediately adjourn the Meeting and declare the polls open for such period of time as he may determine to receive votes by proxy or ballot on items of business properly brought before the Meeting.

Who do I contact if I have questions about the Annual Meeting?

If you need more information about the Meeting, call us at 800-881-5882, or write to Stockholder Services, 231 W. Michigan Street, PO Box 1331, Milwaukee, Wisconsin 53201.

* There is no parking at the Annual Meeting site. Please park at the North Shore Cinema only (11700 N. Port Washington Road, Mequon, WI 53092). Shuttle buses will run from the parking site to the Annual Meeting site.

MAP TO ANNUAL MEETING



STOCKHOLDER NOMINEES AND PROPOSALS

Stockholders wishing to propose director candidates for consideration and recommendation by the Corporate Governance Committee for election at the 2020 Annual Meeting of Stockholders must submit the candidates' names and qualifications to the Corporate Governance Committee no later than November 1, 2019 via the Corporate Secretary, Margaret C. Kelsey. Stockholders may also propose director candidates for consideration and recommendation by the Board by following the guidelines outlined in the Company's bylaws and summarized below.

Stockholders who intend to have a proposal considered for inclusion in the Company's proxy materials for presentation at the 2020 Annual Meeting of Stockholders must submit the proposal to the Company no later than November 22, 2019.

Under our proxy access bylaw, if a stockholder (or a group of up to 20 stockholders) who has owned at least 3% of our shares of common stock for at least three years and has complied with the other requirements set forth in the Company's bylaws wants us to include director nominees (up to the greater of two nominees or 20% of the Board) in our proxy statement for the 2020 Annual Meeting of Stockholders, the nominations must be received by our Corporate Secretary and must arrive at the Company in a timely manner, between 120 and 150 days prior to the anniversary of the date our proxy statement was first sent to stockholders in connection with our last annual meeting, which would be no earlier than October 23, 2019 and no later than November 22, 2019.

Stockholders who intend to present a proposal or director nominee at the 2020 Annual Meeting of Stockholders without inclusion of such proposal or nominee in the Company's proxy materials, are required to provide notice of such proposal or nomination, containing the information required by the Company's bylaws, to the Company at least 70 days and not more than 100 days prior to the scheduled date of the 2020 Annual Meeting of Stockholders. The 2020 Annual Meeting of Stockholders is tentatively scheduled for May 7, 2020.

Correspondence regarding the above should be directed to the Corporate Secretary, Margaret C. Kelsey, at the Company's principal business office, 231 W. Michigan Street, PO Box 1331, Milwaukee, Wisconsin 53201.

AVAILABILITY OF FORM 10-K

A copy (without exhibits) of WEC Energy Group's Annual Report on Form 10-K for the fiscal year ended December 31, 2018, as filed with the SEC, is available without charge to any stockholder of record or beneficial owner of WEC Energy Group common stock by writing to the Corporate Secretary, Margaret C. Kelsey, at the Company's principal business office, 231 W. Michigan Street, PO Box 1331, Milwaukee, Wisconsin 53201. The WEC Energy Group consolidated financial statements and certain other information found in the Form 10-K are provided in our 2018 Annual Financial Statements and Review of Operations. The Form 10-K, along with this proxy statement and all of WEC Energy Group's other filings with the SEC, is also available in the "Investors" section of the Company's Website at wecenergygroup.com.

APPENDIX A – EARNINGS AND EARNINGS PER SHARE GAAP RECONCILIATION

Net Income - Common Stockholders (in millions)	2017
WEC Energy Group GAAP	$ 1,203.7
Tax benefit related to Tax Cuts and Jobs Act of 2017	(206.7)
WEC Energy Group adjusted net income	$ 997.0

Diluted Earnings Per Share	2017	2016	2015	2014
WEC Energy Group GAAP EPS	$ 3.79	$ 2.96	$ 2.34	$ 2.59
Tax benefit related to Tax Cuts and Jobs Act of 2017	(0.65)	—	—	—
Acquisition costs	—	0.01	0.30	0.06
WEC Energy Group adjusted EPS	$ 3.14	$ 2.97	$ 2.64	$ 2.65

We have provided adjusted earnings (non-GAAP earnings) as a complement to, and not as an alternative to, reported earnings presented in accordance with GAAP. For 2017, adjusted earnings exclude a one-time reduction in income tax expense related to a revaluation of our deferred taxes as a result of the Tax Legislation. For 2014 through 2016, adjusted earnings exclude costs related to the acquisition of Integrys. Neither of these items is indicative of the Company's operating performance. Therefore, we believe that the presentation of adjusted earnings is relevant and useful to investors to understand WEC Energy Group's operating performance. Management uses such measures internally to evaluate the Company's performance and manage its operations.

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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

231 W. Michigan St.
P.O. Box 1331
Milwaukee, WI 53201

414-221-2345
wecenergygroup.com

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FPO

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