WEC ENERGY GROUP, INC.
Form 10-Q
November 03, 2017

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the Quarterly Period Ended September 30, 2017

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

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 and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted 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 and post such files).

Yes [X] No [ ]

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

Large accelerated filer [X] Accelerated filer [ ]
Non-accelerated filer [ ] (Do not check if a smaller reporting company)
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]

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date:

Common Stock, $.01 Par Value,
315,575,562 shares outstanding at
September 30, 2017

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For the Quarter Ended September 30, 2017
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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.
ITF	Integrys Transportation Fuels, LLC
MERC	Minnesota Energy Resources Corporation
MGU	Michigan Gas Utilities Corporation
NSG	North Shore Gas Company
PGL	The Peoples Gas Light and Coke Company
UMERC	Upper Michigan Energy Resources Corporation
WBS	WEC Business Services LLC
WE	Wisconsin Electric Power Company
We Power	W.E. Power, LLC
WG	Wisconsin Gas LLC
Wisvest	Wisvest LLC
WPS	Wisconsin Public Service Corporation

Federal and State Regulatory Agencies

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

Accounting Terms

AFUDC	Allowance for Funds Used During Construction
ASU	Accounting Standards Update
FASB	Financial Accounting Standards Board
GAAP	United States Generally Accepted Accounting Principles
LIFO	Last-In, First-Out
OPEB	Other Postretirement Employee Benefits

Environmental Terms

CAA	Clean Air Act
CO_2	Carbon Dioxide
CSAPR	Cross-State Air Pollution Rule
GHG	Greenhouse Gas
NAAQS	National Ambient Air Quality Standards
NOV	Notice of Violation
NOx	Nitrogen Oxide

SO_2	Sulfur Dioxide

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Measurements	
Dth	Dekatherm
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
CNG	Compressed Natural Gas
D.C. Circuit Court of Appeals	United States Court of Appeals for the District of Columbia Circuit
ERGS	Elm Road Generating Station
Exchange Act	Securities Exchange Act of 1934, as amended
FTRs	Financial Transmission Rights
MCPP	Milwaukee County Power Plant
MISO	Midcontinent Independent System Operator, Inc.
MISO Energy Markets	MISO Energy and Operating Reserves Markets
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
PIPP	Presque Isle Power Plant
QIP	Qualifying Infrastructure Plant
ROE	Return on Equity
SMP	Gas System Modernization Program
SMRP	System Modernization and Reliability Project
Supreme Court	United States Supreme Court
VAPP	Valley Power Plant

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

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

Forward-looking statements include, among other things, statements concerning management's expectations and projections regarding earnings, completion of capital projects, sales and customer growth, rate actions and related filings with regulatory authorities, environmental and other regulations and associated compliance costs, legal proceedings, dividend payout ratios, effective tax rate, 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 risk factors as set forth in this report and our Annual Report on Form 10-K for the year ended December 31, 2016, 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 regulatory changes, including changes in rate-setting policies or procedures, tax law changes, 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, and energy efficiency mandates;

- 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 permit conditions by regulatory agencies, and the recovery of associated remediation and compliance costs;

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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;

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- 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 incidents, the threat of terrorist incidents, and cyber security intrusion, including the failure to maintain the security of personally identifiable information, the associated costs to protect our assets and personal information, and the costs to notify affected persons to mitigate their information security concerns;

- The financial performance of ATC and its corresponding contribution to our earnings, as well as the ability of ATC and Duke-American Transmission Company 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 that result in competitive disadvantages and create the potential for impairment of existing assets;

- The timing, costs, and anticipated benefits associated with the remaining integration efforts relating to the Integrys acquisition;

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

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

We expressly disclaim any obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events, or otherwise.

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

WEC ENERGY GROUP, INC.

CONDENSED CONSOLIDATED INCOME STATEMENTS
(Unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
(in millions, except per share amounts)	2017	2016	2017	2016
Operating revenues	$1,657.5	$1,712.5	$5,593.5	$5,509.3
Operating expenses				
Cost of sales	542.7	554.7	2,025.6	1,901.9
Other operation and maintenance	471.7	517.5	1,453.4	1,571.0
Depreciation and amortization	201.2	191.6	593.5	569.5
Property and revenue taxes	48.3	49.7	147.9	146.5
Total operating expenses	1,263.9	1,313.5	4,220.4	4,188.9
Operating income	393.6	399.0	1,373.1	1,320.4
Equity in earnings of transmission affiliate	39.2	38.3	122.9	107.7
Other income, net	16.4	7.5	45.2	72.6
Interest expense	103.8	99.1	310.4	300.1
Other expense	(48.2)	(53.3)	(142.3)	(119.8)
Income before income taxes	345.4	345.7	1,230.8	1,200.6
Income tax expense	129.7	128.4	458.8	455.1
Net income	215.7	217.3	772.0	745.5
Preferred stock dividends of subsidiary	0.3	0.3	0.9	0.9
Net income attributed to common shareholders	$215.4	$217.0	$771.1	$744.6
Earnings per share				
Basic	$0.68	$0.69	$2.44	$2.36
Diluted	$0.68	$0.68	$2.43	$2.35
Weighted average common shares outstanding				
Basic	315.6	315.6	315.6	315.6
Diluted	317.5	316.9	317.5	317.0
Dividends per share of common stock	$0.520	$0.495	$1.560	$1.485

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

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WEC ENERGY GROUP, INC.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (Unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
(in millions)	2017	2016	2017	2016
Net income	$215.7	$217.3	$772.0	$745.5
Other comprehensive (loss) income, net of tax				
Derivatives accounted for as cash flow hedges				
Reclassification of gains to net income, net of tax	(0.4)	(0.3)	(1.0)	(0.9)
Defined benefit plans				
Amortization of pension and OPEB costs (credits) included in net periodic benefit cost, net of tax	0.3	(0.4)	0.5	—
Other comprehensive loss, net of tax	(0.1)	(0.7)	(0.5)	(0.9)
Comprehensive income	215.6	216.6	771.5	744.6
Preferred stock dividends of subsidiary	0.3	0.3	0.9	0.9
Comprehensive income attributed to common shareholders	$215.3	$216.3	$770.6	$743.7

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

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WEC ENERGY GROUP, INC.

CONDENSED CONSOLIDATED BALANCE SHEETS (Unaudited) (in millions, except share and per share amounts)	September 30, 2017	December 31, 2016
Assets		
Current assets		
Cash and cash equivalents	$ 18.1	$ 37.5
Accounts receivable and unbilled revenues, net of reserves of $112.7 and $108.0, respectively	948.0	1,241.7
Materials, supplies, and inventories	672.2	587.6
Prepayments	142.0	204.4
Other	43.0	97.5
Current assets	1,823.3	2,168.7
Long-term assets		
Property, plant, and equipment, net of accumulated depreciation of $8,525.5 and $8,214.6, respectively	20,882.9	19,915.5
Regulatory assets	3,107.7	3,087.9
Equity investment in transmission affiliate	1,560.8	1,443.9
Goodwill	3,053.5	3,046.2
Other	584.8	461.0
Long-term assets	29,189.7	27,954.5
Total assets	$ 31,013.0	$ 30,123.2
Liabilities and Equity		
Current liabilities		
Short-term debt	$ 993.5	$ 860.2
Current portion of long-term debt	709.3	157.2
Accounts payable	743.9	861.5
Accrued payroll and benefits	136.8	163.8
Other	442.6	388.9
Current liabilities	3,026.1	2,431.6
Long-term liabilities		
Long-term debt	8,785.8	9,158.2
Deferred income taxes	5,616.0	5,146.6
Deferred revenue, net	549.2	566.2
Regulatory liabilities	1,534.9	1,563.8
Environmental remediation liabilities	617.7	633.6
Pension and OPEB obligations	463.2	498.6
Other	1,194.4	1,164.4
Long-term liabilities	18,761.2	18,731.4
Commitments and contingencies (Note 17)		
Common shareholders' equity		
Common stock – $0.01 par value; 325,000,000 shares authorized; 315,575,562 and 315,614,941 shares outstanding, respectively	3.2	3.2

Additional paid in capital	4,281.4	4,309.8
Retained earnings	4,908.3	4,613.9
Accumulated other comprehensive income	2.4	2.9
Common shareholders' equity	9,195.3	8,929.8
Preferred stock of subsidiary	30.4	30.4
Total liabilities and equity	$ 31,013.0	$ 30,123.2

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

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WEC ENERGY GROUP, INC.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)	Nine Months Ended September 30	
(in millions)	2017	2016
Operating Activities		
Net income	$772.0	$745.5
Reconciliation to cash provided by operating activities		
Depreciation and amortization	593.5	581.5
Deferred income taxes and investment tax credits, net	444.4	439.5
Contributions and payments related to pension and OPEB plans	(115.4)	(23.5)
Equity income in transmission affiliate, net of distributions	(18.5)	(35.8)
Change in –		
Accounts receivable and unbilled revenues	310.5	185.2
Materials, supplies, and inventories	(84.1)	33.8
Other current assets	57.9	88.5
Accounts payable	(111.2)	(94.7)
Other current liabilities	23.4	(92.9)
Other, net	(125.8)	(105.2)
Net cash provided by operating activities	1,746.7	1,721.9
Investing Activities		
Capital expenditures	(1,309.2)	(1,000.1)
Acquisition of Bluewater	(226.0)	—
Capital contributions to transmission affiliate	(63.3)	(27.1)
Proceeds from the sale of assets and businesses	22.7	161.2
Withdrawal of restricted cash from rabbi trust for qualifying payments	18.7	23.8
Other, net	5.1	0.6
Net cash used in investing activities	(1,552.0)	(841.6)
Financing Activities		
Exercise of stock options	25.6	40.4
Purchase of common stock	(60.6)	(105.6)
Dividends paid on common stock	(492.4)	(468.6)
Issuance of long-term debt	210.0	200.0
Retirement of long-term debt	(26.9)	(253.5)
Change in short-term debt	133.3	(305.6)
Other, net	(3.1)	(12.2)
Net cash used in financing activities	(214.1)	(905.1)
Net change in cash and cash equivalents	(19.4)	(24.8)
Cash and cash equivalents at beginning of period	37.5	49.8
Cash and cash equivalents at end of period	$18.1	$25.0

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

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WEC ENERGY GROUP, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)
September 30, 2017

NOTE 1—GENERAL INFORMATION

WEC Energy Group serves approximately 1.6 million electric customers and 2.8 million natural gas customers, and owns approximately 60% of ATC.

As used in these notes, the term "financial statements" refers to the condensed consolidated financial statements. This includes the income statements, statements of comprehensive income, balance sheets, and statements of cash flows, unless otherwise noted. In this report, when we refer to "the Company," "us," "we," "our," or "ours," we are referring to WEC Energy Group and all of its subsidiaries.

We have prepared the unaudited interim financial statements presented in this Form 10-Q pursuant to the rules and regulations of the SEC and GAAP. Accordingly, these financial statements do not include all of the information and footnotes required by GAAP for annual financial statements. These financial statements should be read in conjunction with the consolidated financial statements and footnotes in our Annual Report on Form 10-K for the year ended December 31, 2016. Financial results for an interim period may not give a true indication of results for the year. In particular, the results of operations for the three and nine months ended September 30, 2017, are not necessarily indicative of expected results for 2017 due to seasonal variations and other factors.

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

NOTE 2—ACQUISITIONS

Acquisition of a Wind Energy Generation Facility in Wisconsin

In October 2017, WPS, along with two other utilities, entered into an agreement to purchase the Forward Wind Energy Center, which consists of 86 wind turbines located in Wisconsin with a total capacity of 129 MWs. The aggregate purchase price is approximately $174 million of which WPS’s proportionate share is 44.6%, or approximately $78 million. WPS currently purchases 44.6% of the facility’s energy output under a power purchase agreement. The transaction is subject to PSCW and FERC approvals and is expected to close in the spring of 2018.

Acquisition of Natural Gas Storage Facilities in Michigan

On June 30, 2017, we completed the acquisition of Bluewater for $226.0 million. Bluewater owns natural gas storage facilities in Michigan that will 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.

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. See Note 15, Segment Information, for more information.

(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

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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 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. 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

In April 2016, as part of the MCPP sale transaction, we sold the chilled water generation and distribution assets of Wisvest, which were 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

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 and presented as held for sale through the sale date. 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—PROPERTY, PLANT, AND EQUIPMENT

Presque Isle Power Plant

In October 2017, the MPSC approved UMERC's application to construct and operate approximately 180 MWs of natural gas-fired generation in the Upper Peninsula of Michigan. Upon receiving this approval, early retirement of the PIPP generating units became probable. The new units are expected to begin commercial operation in 2019 and should allow for the retirement of PIPP no later than 2020. The net book value of these units was $203.0 million at September 30, 2017. These units are currently included in rate base, and WE continues to depreciate them on a straight-line basis using the composite depreciation rates approved by the PSCW. The net book value of these assets was transferred from plant in service to plant to be retired. See Note 19, Regulatory Environment, for more information regarding UMERC's application.

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Edgewater

As a result of the continued implementation of the Consent Decree related to the jointly owned Columbia and Edgewater plants, early retirement of the Edgewater 4 generating unit was probable at September 30, 2017. The net book value of our ownership share of this generating unit was $13.3 million at September 30, 2017. This amount was classified as plant to be retired within property, plant, and equipment on our balance sheet. This unit is currently included in rate base, and WPS continues to depreciate it on a straight-line basis using the composite depreciation rates approved by the PSCW. See Note 17, Commitments and Contingencies, for more information regarding the Consent Decree.

NOTE 5—COMMON EQUITY

Stock-Based Compensation

During the first quarter of 2017, the Compensation Committee of our Board of Directors awarded the following stock-based compensation awards to our directors, officers, and certain other key employees:

Award Type	Number of Awards
Stock options [1]	552,215
Restricted shares [2]	82,622
Performance units	237,650

[1] Stock options awarded had a weighted-average exercise price of $58.31 and a weighted-average grant date fair value of $7.45 per option.

[2] Restricted shares awarded had a weighted-average grant date fair value of $58.10 per share.

In March 2016, the FASB issued ASU 2016-09, Improvements to Employee Share-Based Payment Accounting, which modifies 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 retained earnings for excess tax benefits that had not been recognized in prior years as they did not reduce taxes payable. The following table shows the changes to our retained earnings for the nine months ended September 30, 2017:

(in millions)	Retained Earnings
Balance at December 31, 2016	$4,613.9
Net income attributed to common shareholders	771.1
Common stock dividends	(492.4)
Cumulative effect of adoption of ASU 2016-09	15.7
Balance at September 30, 2017	$4,908.3

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

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 subsidiary, We Power. 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. See Note 11, Common Equity, in our 2016 Annual Report on Form 10-K for additional information on these and other restrictions.

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

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Common Stock Dividends

On October 19, 2017, our Board of Directors declared a quarterly cash dividend of $0.52 per share, payable on December 1, 2017, to stockholders of record on November 14, 2017.

NOTE 6—SHORT-TERM DEBT AND LINES OF CREDIT

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

(in millions, except percentages)	September 30, 2017	December 31, 2016
Commercial paper		
Amount outstanding	$ 993.5	$ 860.2
Weighted-average interest rate on amounts outstanding	1.38 %	0.96 %

Our average amount of commercial paper borrowings based on daily outstanding balances during the nine months ended September 30, 2017, was $705.0 million with a weighted-average interest rate during the period of 1.21%.

The information in the table below relates to our revolving credit facilities used to support our commercial paper borrowing programs, including available capacity under these facilities:

(in millions)	Maturity	September 30, 2017
WEC Energy Group [1]	December 2020	$ 1,050.0
WE [2]	December 2020	500.0
WPS [3]	December 2020	250.0
WG [2]	December 2020	350.0
PGL [2]	December 2020	350.0
Total short-term credit capacity		$ 2,500.0
Less:		
Letters of credit issued inside credit facilities		$ 32.9
Commercial paper outstanding		993.5
Available capacity under existing agreements		$ 1,473.6

(1) In October 2017, WEC Energy Group increased its credit facility to $1,200.0 million, and extended the maturity to October 2022.

(2) In October 2017, WE, WG, and PGL extended the maturities of their credit facilities to October 2022.

(3) In October 2017, WPS increased its credit facility to $400.0 million. WPS intends to request approval from the PSCW to extend the maturity of its facility to October 2022.

NOTE 7—LONG-TERM DEBT

Effective May 2017, the $500.0 million of 2007 Junior Notes bear interest at the three-month LIBOR plus 211.25 basis points, and reset quarterly.

In June 2017, MERC issued $120.0 million of senior notes. The senior notes were issued in three tranches: $40.0 million of 3.11% Senior Notes due July 15, 2027; $40.0 million of 3.41% Senior Notes due July 15, 2032; and $40.0 million of 4.01% Senior Notes due July 15, 2047. Net proceeds were used to repay MERC's $78.0 million aggregate long-term debt obligation to its parent, Integrys. Remaining proceeds were used for general corporate purposes,

including repayment of short-term debt borrowed from Integrys.

In June 2017, MGU issued $90.0 million of senior notes. The senior notes were issued in three tranches: $30.0 million of 3.11% Senior Notes due July 15, 2027; $30.0 million of 3.41% Senior Notes due July 15, 2032; and $30.0 million of 4.01% Senior Notes due July 15, 2047. Net proceeds were used to repay MGU's $71.0 million aggregate long-term debt obligation to its parent, Integrys. Remaining proceeds were used for general corporate purposes, including repayment of short-term debt borrowed from Integrys.

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NOTE 8—MATERIALS, SUPPLIES, AND INVENTORIES

Our inventory consisted of:

(in millions)	September 30, 2017	December 31, 2016
Natural gas in storage	$ 301.5	$ 223.1
Materials and supplies	225.1	206.5
Fossil fuel	145.6	158.0
Total	$ 672.2	$ 587.6

PGL and NSG price natural gas storage injections at the calendar year average of the cost of natural gas supply purchased. Withdrawals from storage are priced using the LIFO cost method. For interim periods, the difference between current projected replacement cost and the LIFO cost for quantities of natural gas temporarily withdrawn from storage is recorded as a temporary LIFO liquidation debit or credit. At September 30, 2017, all LIFO layers were replenished, and the LIFO liquidation balance was zero.

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

NOTE 9—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 financial 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.

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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:

	September 30, 2017			
(in millions)	Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	$2.8	$3.7	$—	$6.5
Petroleum products contracts	1.0	—	—	1.0
FTRs	—	—	7.3	7.3
Coal contracts	—	0.9	—	0.9
Total derivative assets	$3.8	$4.6	$7.3	$15.7
Investments held in rabbi trust	$113.5	$—	$—	$113.5
Derivative liabilities				
Natural gas contracts	$1.5	$2.5	$—	$4.0
Coal contracts	—	2.1	—	2.1
Total derivative liabilities	$1.5	$4.6	$—	$6.1

	December 31, 2016			
(in millions)	Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	$10.1	$24.2	$—	$34.3
Petroleum products contracts	0.2	—	—	0.2
FTRs	—	—	5.1	5.1
Coal contracts	—	2.0	—	2.0
Total derivative assets	$10.3	$26.2	$5.1	$41.6
Investments held in rabbi trust	$103.9	$—	$—	$103.9
Derivative liabilities				
Natural gas contracts	$0.2	$0.2	$—	$0.4
Petroleum products contracts	0.1	—	—	0.1
Coal contracts	—	1.9	—	1.9
Total derivative liabilities	$0.3	$2.1	$—	$2.4

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.

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

	Three Months Ended September 30		Nine Months Ended September 30	
(in millions)	2017	2016	2017	2016
Balance at the beginning of the period	$11.8	$13.4	$5.1	$3.6
Realized and unrealized losses	—	—	—	(0.2)
Purchases	—	—	13.8	15.2

Sales	—	—	—	(0.2)
Settlements	(4.5)	(4.2)	(11.6)	(9.2)
Balance at the end of the period	$7.3	$9.2	$7.3	$9.2

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.

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Fair Value of Financial Instruments

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

(in millions)	September 30, 2017		December 31, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Preferred stock	$ 30.4	$ 29.6	$ 30.4	$ 28.8
Long-term debt, including current portion *	9,467.5	10,135.2	9,285.8	9,818.2

* The carrying amount of long-term debt excludes capital lease obligations of $27.6 million and $29.6 million at September 30, 2017 and December 31, 2016, respectively.

Due to the short-term nature of cash and cash equivalents, net accounts receivable and unbilled revenues, accounts payable, and short-term debt, the carrying amount of each such item approximates fair value. The fair value of our preferred stock is estimated based on the quoted market value for the same issue, or by using a dividend discount model. The fair value of our long-term debt is estimated based upon the quoted market value for the same issue, similar issues, or upon the quoted market prices of United States Treasury issues having a similar term to maturity, adjusted for the issuing company's bond rating and the present value of future cash flows. The fair values of our long-term debt and preferred stock are categorized within Level 2 of the fair value hierarchy.

NOTE 10—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 and shareholders. Our approach is non-speculative and designed to mitigate risk. Regulated hedging programs are approved by our state regulators.

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

The following table shows our derivative assets and derivative liabilities:

(in millions)	September 30, 2017		December 31, 2016	
	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Other current				
Natural gas contracts	$ 5.4	$ 4.0	$ 31.4	$ 0.4
Petroleum products contracts	1.0	—	0.2	0.1
FTRs	7.3	—	5.1	—
Coal contracts	0.6	1.4	1.5	1.4
Total other current *	$ 14.3	$ 5.4	$ 38.2	$ 1.9

Other long-term

Natural gas contracts	$ 1.1	$ —	$ 2.9	$ —
Coal contracts	0.3	0.7	0.5	0.5
Total other long-term *	$ 1.4	$ 0.7	$ 3.4	$ 0.5
Total	$ 15.7	$ 6.1	$ 41.6	$ 2.4

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

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Realized gains (losses) on derivative instruments are primarily recorded in cost of sales on the income statements. Our estimated notional sales volumes and realized gains (losses) were as follows:

	Three Months Ended September 30, 2017		Three Months Ended September 30, 2016	
(in millions)	Volumes	Gains (Losses)	Volumes	Gains (Losses)
Natural gas contracts	24.9 Dth	$ (2.1)	30.5 Dth	$ (3.4)
Petroleum products contracts	4.4 gallons	(0.5)	4.3 gallons	(0.4)
FTRs	9.4 MWh	4.2	9.9 MWh	7.1
Total		$ 1.6		$ 3.3

	Nine Months Ended September 30, 2017		Nine Months Ended September 30, 2016	
(in millions)	Volumes	Gains (Losses)	Volumes	Gains (Losses)
Natural gas contracts	84.2 Dth	$ (1.1)	113.3 Dth	$ (56.9)
Petroleum products contracts	14.2 gallons	(1.4)	10.9 gallons	(2.5)
FTRs	28.0 MWh	9.4	24.9 MWh	11.7
Total		$ 6.9		$ (47.7)

On our balance sheets, the amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against the fair value amounts recognized for derivative instruments executed with the same counterparty under the same master netting arrangement. At September 30, 2017 and December 31, 2016, we had posted cash collateral of $24.7 million and $16.4 million, respectively, in our margin accounts. These amounts were recorded on our balance sheets in other current assets. At December 31, 2016, we had also received cash collateral of $4.4 million in our margin accounts. This amount was recorded on our balance sheet in other current liabilities.

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

	September 30, 2017		December 31, 2016	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Gross amount recognized on the balance sheet	$ 15.7	$ 6.1	$ 41.6	$ 2.4
Gross amount not offset on the balance sheet	(3.0)	(3.1) [1]	(4.9) [2]	(0.5)
Net amount	$ 12.7	$ 3.0	$ 36.7	$ 1.9

[1] Includes cash collateral posted of $0.1 million.

[2] Includes cash collateral received of $4.4 million.

Certain of our derivative and nonderivative 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. The aggregate fair value of all derivative instruments with specific credit risk-related contingent features that were in a net liability position was $2.3 million and $0.2 million at September 30, 2017 and December 31, 2016, respectively. At September 30, 2017 and December 31, 2016, we had not posted any 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 September 30, 2017, we would have been required to post collateral of $0.8 million. At December 31, 2016, we would not have been required to post any collateral.

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NOTE 11—GUARANTEES

The following table shows our outstanding guarantees:

(in millions)	Total Amounts Committed at September 30, 2017	Expiration Less Than 1 Year	1 to 3 Years	Over 3 Years
Guarantees				
Guarantees supporting commodity transactions of subsidiaries [1]	$ 8.1	$8.1	$ —	$—
Standby letters of credit [2]	35.8	28.7	7.1	—
Surety bonds [3]	9.7	9.7	—	—
Other guarantees [4]	11.1	0.5	—	10.6
Total guarantees	$ 64.7	$47.0	$ 7.1	$ 10.6

(1) Consists of $8.1 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 $11.1 million related to other indemnifications, for which a liability of $10.6 million related to workers compensation coverage was recorded on our balance sheets.

NOTE 12—EMPLOYEE BENEFITS

The following tables show the components of net periodic pension and OPEB costs for our benefit plans.

	Pension Costs			
	Three Months Ended September 30		Nine Months Ended September 30	
(in millions)	2017	2016	2017	2016
Service cost	$11.1	$10.9	$33.2	$32.9
Interest cost	30.3	33.2	91.7	99.4
Expected return on plan assets	(48.8)	(49.0)	(146.9)	(147.0)
Loss on plan settlement	2.9	0.7	8.2	14.8
Amortization of prior service cost	0.7	0.9	2.2	2.6
Amortization of net actuarial loss	21.5	20.4	64.5	61.1
Net periodic benefit cost	$17.7	$17.1	$52.9	$63.8

	OPEB Costs			
	Three Months Ended September 30		Nine Months Ended September 30	
(in millions)	2017	2016	2017	2016

Service cost	$6.0	$6.5	$17.9	$19.6
Interest cost	8.4	9.2	25.3	27.7
Expected return on plan assets	(13.6)	(13.2)	(40.9)	(39.6)
Amortization of prior service credit	(2.8)	(2.3)	(8.4)	(7.0)
Amortization of net actuarial loss	0.7	2.2	2.3	6.4
Net periodic benefit (credit) cost	$(1.3)	$2.4	$(3.8)	$7.1

During the nine months ended September 30, 2017, we made payments of $109.8 million to our pension plans and $5.6 million to our OPEB plans. We expect to make payments of $3.8 million related to our pension plans and $3.9 million related to our OPEB plans during the remainder of 2017, dependent upon various factors affecting us, including our liquidity position and possible tax law changes.

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NOTE 13—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 nine months ended September 30, 2017:

(in millions)	Wisconsin	Illinois	Other States	Non-Utility Energy Infrastructure	Total
Goodwill balance as of January 1, 2017	$ 2,104.3	$758.7	$183.2	$ —	$3,046.2
Acquisition of Bluewater [1]	—	—	—	7.3	7.3
Goodwill balance as of September 30, 2017 [2]	$ 2,104.3	$758.7	$183.2	$ 7.3	$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 September 30, 2017.

In the third quarter of 2017, annual impairment tests were completed at all of our reporting units that carried a goodwill balance as of July 1, 2017. No impairments resulted from these tests.

NOTE 14—INVESTMENT IN AMERICAN TRANSMISSION COMPANY

We own approximately 60% of ATC, a for-profit, electric transmission company regulated by the FERC and certain state regulatory commissions. The following table shows changes to our investment in ATC:

	Three Months Ended September 30		Nine Months Ended September 30	
(in millions)	2017	2016	2017	2016
Balance at beginning of period	$1,544.0	$1,425.0	$1,443.9	$1,380.9
Add: Earnings from equity method investment	39.2	38.3	122.9	107.7
Add: Capital contributions	12.8	15.0	63.3	27.1
Add: Acquisition of Integrys's investment in ATC	—	—	—	(1.0)[1]
Add: Adjustment to equity method goodwill	—	—	—	10.4
Less: Distributions	35.2	25.2	69.2 [2]	71.9
Less: Other	—	—	0.1	0.1
Balance at end of period	$1,560.8	$1,453.1	$1,560.8	$1,453.1

[1] Amount reflects an adjustment to the allocation of the purchase price for Integrys made in the second quarter of 2016.

[2] Distributions of $35.2 million, received in the first quarter of 2017, were approved and recorded in December 2016.

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 are 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:

	Three Months Ended September 30		Nine Months Ended September 30	
(in millions)	2017	2016	2017	2016
Charges to ATC for services and construction	$ 4.4	$ 4.4	$ 12.3	$ 12.8
Charges from ATC for network transmission services	87.4	89.3	262.0	271.4
Refund from ATC per FERC ROE order	—	—	(28.3)	—

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Our balance sheets included the following receivables and payables related to ATC:

(in millions)	September 30, 2017	December 31, 2016
Accounts receivable		
Services provided to ATC	$ 1.5	$ 2.2
Accounts payable		
Services received from ATC	29.1	28.7

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

	Three Months Ended September 30		Nine Months Ended September 30	
(in millions)	2017	2016	2017	2016
Income statement data				
Revenues	$171.1	$158.1	$522.4	$476.6
Operating expenses	85.0	80.2	250.1	241.0
Other expense	27.5	23.5	79.6	71.2
Net income	$58.6	$54.4	$192.7	$164.4

(in millions)	September 30, 2017	December 31, 2016
Balance sheet data		
Current assets	$ 89.0	$ 75.8
Noncurrent assets	4,564.9	4,312.9
Total assets	$ 4,653.9	$ 4,388.7
Current liabilities	$ 772.1	$ 495.1
Long-term debt	1,740.8	1,865.3
Other noncurrent liabilities	213.8	271.5
Shareholders' equity	1,927.2	1,756.8
Total liabilities and shareholders' equity	$ 4,653.9	$ 4,388.7

NOTE 15—SEGMENT INFORMATION

At September 30, 2017, we reported six segments, which are described below.

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

- 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, electric transmission company regulated by the FERC and certain state regulatory commissions.

- Following the acquisition of Bluewater, our We Power segment was renamed the non-utility energy infrastructure segment. This segment includes We Power, which owns and leases generating facilities to WE, and Bluewater, which

owns underground natural gas storage facilities in Michigan. See Note 2, Acquisitions, for more information on the Bluewater transaction.

The corporate and other segment includes the operations of the WEC Energy Group holding company, the Integrys holding company, the Peoples Energy, LLC holding company, Wispark LLC, Bostco, Wisvest, Wisconsin Energy Capital Corporation, WBS, WPS Power Development LLC, and ITF. In the first quarter of 2017, we sold substantially all of the remaining assets of Bostco and in the second quarter of 2016, we sold certain assets of Wisvest. The sale of ITF was completed in the first quarter of 2016. See Note 3, Dispositions, for more information on these sales.

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All of our operations are located within the United States. The following tables show summarized financial information related to our reportable segments for the three and nine months ended September 30, 2017 and 2016:

	Utility Operations								
(in millions)	Wisconsin	Illinois	Other States	Total Utility Operations	Electric Transmission	Non-Utility Energy Infrastructure	Corporate and Other	Reconciling Eliminations	WEC Energy Group Consolidated
Three Months Ended September 30, 2017									
External revenues	$1,401.3	$187.2	$49.8	$1,638.3	$—	$13.6	$5.6	$—	$1,657.5
Intersegment revenues	—	—	—	—	—	111.6	—	(111.6)	—
Other operation and maintenance	458.3	100.8	21.6	580.7	—	1.5	(1.5)	(109.0)	471.7
Depreciation and amortization	131.5	38.9	6.3	176.7	—	18.2	6.3	—	201.2
Operating income (loss)	279.7	12.5	(3.1)	289.1	—	103.4	1.1	—	393.6
Equity in earnings of transmission affiliate	—	—	—	—	39.2	—	—	—	39.2
Interest expense	48.5	11.0	2.3	61.8	—	16.2	25.4	0.4	103.8

	Utility Operations								
(in millions)	Wisconsin	Illinois	Other States	Total Utility Operations	Electric Transmission	Non-Utility Energy Infrastructure	Corporate and Other	Reconciling Eliminations	WEC Energy Group Consolidated
Three Months Ended September 30, 2016									
External revenues	$1,470.6	$181.8	$49.9	$1,702.3	$—	$6.2	$4.0	$—	$1,712.5
Intersegment revenues	—	—	—	—	—	105.0	—	(105.0)	—
Other operation and maintenance	498.2	105.9	21.2	625.3	—	0.4	(3.2)	(105.0)	517.5
Depreciation and amortization	124.5	33.5	5.2	163.2	—	17.1	11.3	—	191.6
Operating income (loss)	299.1	11.7	(1.0)	309.8	—	93.7	(4.5)	—	399.0
Equity in earnings of transmission affiliate	—	—	—	—	38.3	—	—	—	38.3
Interest expense	44.6	9.3	1.9	55.8	—	15.6	29.7	(2.0)	99.1

	Utility Operations								
(in millions)	Wisconsin	Illinois	Other States	Total Utility Operations	Electric Transmission	Non-Utility Energy Infrastructure	Corporate and Other	Reconciling Eliminations	WEC Energy Group Consolidated
Nine Months Ended September 30, 2017									
External revenues	$4,316.6	$965.7	$273.4	$5,555.7	$—	$26.1	$11.7	$—	$5,593.5
Intersegment revenues	—	—	—	—	—	333.2	—	(333.2)	—
Other operation and maintenance	1,379.9	326.6	73.2	1,779.7	—	4.6	(0.3)	(330.6)	1,453.4

Depreciation and amortization	391.1	112.6	18.4	522.1	—	53.1	18.3	—	593.5
Operating income (loss)	835.6	209.3	35.0	1,079.9	—	299.5	(6.3)	—	1,373.1
Equity in earnings of transmission affiliate	—	—	—	—	122.9	—	—	—	122.9
Interest expense	145.4	33.0	6.5	184.9	—	46.7	81.3	(2.5)	310.4

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	Utility Operations								
(in millions)	Wisconsin	Illinois	Other States	Total Utility Operations	Electric Transmission	Non-Utility Energy Infrastructure	Corporate and Other	Reconciling Eliminations	WEC Energy Group Consolidated
Nine Months Ended September 30, 2016									
External revenues	$4,354.9	$853.1	$262.3	$5,470.3	$—	$18.7	$20.3	$—	$5,509.3
Intersegment revenues	0.3	—	—	0.3	—	317.1	—	(317.4)	—
Other operation and maintenance	1,477.3	340.0	80.6	1,897.9	—	3.5	(13.0)	(317.4)	1,571.0
Depreciation and amortization	370.1	99.4	15.5	485.0	—	51.1	33.4	—	569.5
Operating income (loss)	841.3	171.3	33.1	1,045.7	—	281.1	(6.4)	—	1,320.4
Equity in earnings of transmission affiliate	—	—	—	—	107.7	—	—	—	107.7
Interest expense	133.5	28.8	6.5	168.8	—	46.8	91.2	(6.7)	300.1

NOTE 16—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

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. We account for ATC as an equity method investment. See Note 14, Investment in American Transmission Company, for more information.

The significant assets and liabilities related to ATC recorded on our balance sheets include our equity investment, distributions receivable, and accounts payable. At September 30, 2017 and December 31, 2016, our equity investment was $1,560.8 million and $1,443.9 million, respectively, which approximates our maximum exposure to loss as a result of our involvement with ATC. In addition, we had a receivable of $35.2 million recorded at December 31, 2016 for distributions from ATC. We also had $29.1 million and $28.7 million of accounts payable due to ATC at September 30, 2017 and December 31, 2016, respectively, for network transmission services.

Purchased Power Agreement

We have a purchased power agreement that represents a variable interest. This agreement is for 236 MWs 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 five 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 approximately $74.9 million of required payments over the remaining term of this agreement. We believe that the required lease payments under this contract will continue to be recoverable in rates. Total capacity and lease payments under this contract for

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the nine months ended September 30, 2017 and 2016 were $13.5 million and $40.5 million, respectively. Our maximum exposure to loss is limited to the capacity payments under the contract.

NOTE 17—COMMITMENTS AND CONTINGENCIES

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

Unconditional Purchase Obligations

Our electric utilities have obligations to distribute and sell electricity to their customers, and our natural gas utilities have obligations to distribute and sell natural gas to their customers. The utilities expect to recover costs related to these obligations in future customer rates. In order to meet these obligations, we routinely enter into long-term purchase and sale commitments for various quantities and lengths of time. Our minimum future commitments related to these purchase obligations as of September 30, 2017, including those of our subsidiaries, were $11,863.2 million.

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 discharges; disposal of coal combustion products such as fly ash; and remediation of impacted properties, including former manufactured gas plant sites.

Air Quality

Cross-State Air Pollution Rule

In July 2011, the EPA issued the CSAPR, which replaced a previous rule, the Clean Air Interstate Rule. The purpose of the CSAPR was to limit the interstate transport of NOx and SO_2 that contribute to fine particulate matter and ozone nonattainment in downwind states through a proposed allowance allocation and trading plan. After several lawsuits and related appeals, in October 2014, the D.C. Circuit Court of Appeals issued a decision that allowed the EPA to begin implementing the CSAPR on January 1, 2015. The emissions budgets of Phase I of the rule applied in 2015 and 2016, while the Phase II emissions budgets apply to 2017 and beyond.

The EPA published its proposed update to the CSAPR for the 2008 ozone NAAQS in December 2015 and issued the final rule in September 2016. We remain well positioned to meet the rule requirements and do not expect to incur significant costs to comply with this rule.

Sulfur Dioxide National Ambient Air Quality Standards

The EPA issued a revised 1-Hour SO_2 NAAQS that became effective in August 2010. The EPA issued a final rule in August 2015 describing the implementation requirements and established a compliance timeline for the revised standard. The final rule affords state agencies some latitude in rule implementation. A nonattainment designation could have negative impacts for a localized geographic area, including additional permitting requirements for new or existing sources in the area. In June 2016, we provided modeling to the WDNR that shows the area around the Weston Power Plant to be in compliance. Based upon the submittal, the WDNR provided final modeling to the EPA demonstrating the area around the Weston Power Plant to be in compliance. We expect that the EPA will consider the WDNR's recommendation and will finalize its designation by the end of 2017. We believe our fleet overall is well

positioned to meet the regulation and do not expect to incur significant costs to comply with this regulation.

8-Hour Ozone National Ambient Air Quality Standards

Sheboygan County and the eastern portion of Kenosha County are currently designated as nonattainment with the 2008 ozone standard. In response, Wisconsin has updated the 2008 ozone NAAQS attainment plans for both Sheboygan and Kenosha County and submitted them to the EPA for approval. The plans concluded that Wisconsin will not need to implement any new regulatory measures or programs. The area is forecasted to meet the standard by the 2018 compliance date due to emission control measures already in place. We expect the EPA to issue a decision later in 2017.

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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. This is expected to cause nonattainment for Wisconsin's Lake Michigan shoreline counties (or partial counties), with potential future impacts for our fossil-fueled power plant fleet. In January 2017, the EPA released preliminary interstate ozone transport modeling for the 2015 ozone NAAQS. The EPA is currently scheduled to finalize designations later in 2017. For nonattainment areas, the state of Wisconsin will have to develop a state implementation plan to bring the areas back into attainment. We will be required to comply with this state implementation plan no earlier than 2020. We will not know the potential impacts for complying with the 2015 ozone NAAQS until the designations are final and until the state prepares a draft attainment plan.

Although we are still in the process of reviewing and determining potential impacts resulting from this rule, we believe we are well positioned to meet the ozone standard and do not expect to incur significant costs to comply.

Climate Change

In 2015, the EPA issued a final rule regulating GHG emissions from existing generating units, referred to as the Clean Power Plan (CPP), a proposed federal plan and model trading rules as alternatives or guides to state compliance plans, and final performance standards for modified and reconstructed generating units and new fossil-fueled power plants. In October 2015, following publication of the CPP, numerous states (including Wisconsin and Michigan) and other parties, filed lawsuits challenging the final rule, including a request to stay the implementation of the final rule pending the outcome of these legal challenges. The D.C. Circuit Court of Appeals denied the stay request, but in February 2016, the Supreme Court stayed the effectiveness of the CPP until disposition of the litigation in the D.C. Circuit Court of Appeals and to the extent that further appellate review is sought, at the Supreme Court. The D.C. Circuit Court of Appeals heard one case in September 2016, and the other case is still pending. In April 2017, pursuant to motions made by the EPA, the D.C. Circuit Court of Appeals ordered the cases to be held in abeyance. Supplemental briefs were provided addressing whether the cases should be remanded to the EPA rather than held in abeyance. The EPA argued that the cases should continue to be held in abeyance pending the conclusion of the EPA's review of the CPP and any resulting rulemaking.

The CPP seeks to achieve state-specific GHG emission reduction goals by 2030, and would have required states to submit plans by September 2016. The goal of the final rule is to reduce nationwide GHG emissions by 32% from 2005 levels. The rule is seeking GHG emission reductions in Wisconsin and Michigan of 41% and 39%, respectively, below 2012 levels by 2030. Interim goals starting in 2022 would require states to achieve about two-thirds of the 2030 required reduction.

In March 2017, President Trump issued an executive order that, among other things, specifically directs the EPA to review, and if appropriate, initiate proceedings to suspend, revise, or rescind the CPP and related GHG regulations for new, reconstructed, or modified fossil-fueled power plants. The EPA announced that it has initiated this review. As a result of this order and related EPA review, as well as the ongoing legal proceedings, the timelines for the GHG emission reduction goals and all other aspects of the CPP are uncertain. In April 2017, the EPA withdrew the proposed rule for a federal plan and model trading rules that were published in October 2015 for use in developing state plans to implement the CPP or for use in states where a plan is not submitted or approved. In October 2017, the EPA issued a notice of proposed rulemaking to repeal the CPP. The EPA is expected subsequently to issue an advanced notice of proposed rulemaking that will solicit input on whether it is appropriate to replace the CPP. In addition, the Governor of Wisconsin issued an executive order in February 2016, which prohibits state agencies, departments, boards, commissions, or other state entities from developing or promoting the development of a state plan.

Notwithstanding the uncertain future of the CPP, and given current fuel and technology markets, 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 a goal of reducing CO_2 emissions by approximately 40% below 2005 levels by 2030. We have implemented and continue to evaluate numerous options in order to meet our CO_2 reduction goal, such as increased use of existing natural gas combined cycle units, co-firing or switching to natural gas in existing coal-fired units, reduced operation or retirement of existing coal-fired units, addition of new renewable energy resources (wind, solar), and consideration of supply and demand-side energy efficiency and distributed generation.

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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, which requires that the location, design, construction, and capacity of cooling water intake structures at existing power plants reflect the Best Technology Available (BTA) for minimizing adverse environmental impacts from both impingement (entrapping organisms on water intake screens) and entrainment (drawing organisms into water intake). 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.

Facility owners must select from seven compliance options available to meet the impingement mortality (IM) reduction standard. The rule requires state permitting agencies to make BTA determinations, subject to EPA oversight, for IM reduction 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 Pulliam Units 7 and 8 and Weston Unit 2, satisfy the IM BTA requirements. We plan to evaluate the available IM options for Pulliam Units 7 and 8. We also expect that limited studies will be required to support the future WDNR BTA determinations for Weston Unit 2. Based on preliminary discussions with the WDNR, we anticipate that the WDNR will not require physical modifications to the Weston Unit 2 intake structure to meet the IM BTA requirements based on low capacity use of the unit.

BTA determinations must also be made by the WDNR and MDEQ to address entrainment mortality (EM) reduction on a site-specific basis taking into consideration several factors. We have received an EM BTA determination by the WDNR, with EPA concurrence, for our intake modification at VAPP. BTA determinations for EM will be made in future permit reissuances for Pulliam Units 7 and 8, Weston Units 2 through 4, Port Washington Generating Station, Pleasant Prairie Power Plant, PIPP, and OC 5 through OC 8.

During 2017 and 2018, we will continue to complete studies and evaluate options to address the EM BTA requirements at these plants. With the exception of Pleasant Prairie Power Plant and Weston Units 3 and 4 (which all have existing cooling towers that meet EM BTA requirements), we cannot yet determine what, if any, intake structure or operational modifications will be required to meet the new EM BTA requirements at the facilities. We also expect that limited studies to support WDNR BTA determinations will be conducted at the Weston facility. Based on preliminary discussions with the WDNR, we anticipate that the WDNR will not require physical modifications to the Weston Unit 2 intake structure to meet the EM BTA requirements based on low capacity use of the unit. We provided information to the MDEQ about unit retirements. Based on discussions with the MDEQ, if we submit a signed certification stating that PIPP will be retired no later than the end of the next permit cycle (assumed to be October 1, 2022), the EM BTA requirements will be waived. We expect to submit this certification in November 2017. We expect to submit entrainment studies being conducted at Pulliam Units 7 and 8 to the WDNR by June 2018.

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. 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 to postpone the earliest compliance dates for the bottom ash transport water and wet flue gas desulfurization wastewater requirements. This rule applies to wastewater discharges from our power plant processes in Wisconsin and Michigan. While the ELG compliance deadlines are postponed, the WDNR and the

MDEQ have indicated that they will refrain from incorporating certain new requirements into any reissued discharge permits between 2018 and 2023.

After a final rule is back in effect, the WDNR and MDEQ have indicated that they will modify the state rules as necessary and incorporate the new requirements into our facility permits, which are renewed every five years. 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.

The final rule would phase in new or more stringent requirements related to limits of arsenic, mercury, selenium, and nitrogen in wastewater discharged from wet scrubber systems. New requirements for wet scrubber wastewater treatment would require additional zero liquid discharge or other advanced treatment capital improvements for the Oak Creek site and Pleasant Prairie

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facilities. The rule also would require dry fly ash handling, which is already in place at all of our power plants. Dry bottom ash transport systems are required by the new rule, and modifications would be required at OC 7, OC 8, the Pleasant Prairie units, Pulliam Units 7 and 8, and Weston Unit 3. We are beginning preliminary engineering for compliance with the rule and estimate a total cost range of $80 million to $110 million for these advanced treatment and bottom ash transport systems. A similar system would be required at PIPP if we were not expecting to retire the plant. See the UMERC discussion in Note 19, Regulatory Environment, regarding the potential retirement of PIPP.

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:

(in millions)	September 30, 2017	December 31, 2016
Regulatory assets	$ 683.3	$ 702.7
Reserves for future remediation	617.5	633.4

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

In November 2009, the EPA issued a NOV to WPS, 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. 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.

Also, in May 2010, WPS received from the Sierra Club a Notice of Intent to file a civil lawsuit based on allegations that WPS violated the CAA at the Weston and Pulliam plants. WPS entered into a Standstill Agreement with the Sierra Club by which the parties agreed to negotiate as part of the EPA NOV process, rather than litigate. The Standstill Agreement ended in October 2012, but no further action has been taken by the Sierra Club as of September 30, 2017. It is unknown whether the Sierra Club will take further action in the future.

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Joint Ownership Power Plants Consent Decree – Columbia and Edgewater

In December 2009, the EPA issued a 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 Consent Decree contains a requirement to, among other things, refuel, repower, or retire Edgewater Unit 4, of which WPS is a joint owner, by no later than December 31, 2018. Management of the joint owners has recommended that Edgewater Unit 4 be retired by December 2018. See Note 4, Property, Plant, and Equipment, for more information about the retirement.

NOTE 18—SUPPLEMENTAL CASH FLOW INFORMATION

	Nine Months Ended September 30	
(in millions)	2017	2016
Cash (paid) for interest, net of amount capitalized	$(258.2)	$(260.7)
Cash received for income taxes, net	7.3	11.7
Significant non-cash transactions		
Accounts payable related to construction costs	172.7	113.1
Increase (decrease) in restricted cash from the sale (purchase) of investments held in the rabbi trust	4.6	(4.5)
Portion of Bostco real estate holdings sale financed with note receivable *	7.0	—
Amortization of deferred revenue	18.7	18.5

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

At September 30, 2017, and December 31, 2016, restricted cash of $20.4 million and $33.6 million, respectively, was recorded within other long-term assets on our balance sheets. The majority of this amount was held in the Integrys rabbi trust and represents a portion of the required funding that was triggered by the announcement of the Integrys acquisition. Withdrawals of restricted cash from the rabbi trust for qualifying payments are shown as an investing activity on the statements of cash flows. Changes in restricted cash due to the sale or purchase of investments held in the rabbi trust are non-cash transactions and are included in the table above.

NOTE 19—REGULATORY ENVIRONMENT

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 will freeze base rates through 2019 for electric, 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. Various intervenors have filed requests for rehearing.

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. In addition, WE, WG, and WPS will defer the revenue requirement impacts of any federal corporate tax reform enacted in 2017 or during the base rate freeze period. 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 WPS's electric real-time market pricing program and network transmission expenses. The total cost of the ReACT™ project, excluding $51 million of AFUDC, is currently estimated to be $342 million.

Pursuant to the settlement agreement, WPS also agreed to adopt, beginning in 2018, the earnings sharing mechanism currently in place for WE and WG, and all three utilities agreed to keep the mechanism in place through 2019. Under this earnings sharing

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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.

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 would provide approximately one-third of the current storage needs for the natural gas distribution service customers 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 finalized the long-term service agreements for the natural gas storage and filed with the PSCW for approval of these agreements. We expect to receive approval of the service agreements in the fourth quarter of 2017. See Note 2, Acquisitions, for more information.

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 commenced in January 2016 and 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. In March 2017, the ICC issued an order directing that additional hearings be held before the ALJ on certain issues to further develop the evidentiary record in the case. This proceeding is expected to result in a final order by the ICC in 2017. We are currently unable to determine what, if any, long-term impact there will be on the SMP.

Qualifying Infrastructure Plant Rider

In July 2013, Illinois Public Act 98-0057, The Natural Gas Consumer, Safety & Reliability Act, became law. The Act 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 2017, PGL filed its 2016 reconciliation with the ICC, which, along with the 2015 reconciliation, is still pending. For PGL's 2014 reconciliation, the ICC staff and the Illinois Attorney General's office held an evidentiary hearing in September 2017, and we expect to receive an order related to the 2014 reconciliation in 2017. As of September 30, 2017, 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.

Minnesota Energy Resources Corporation

2018 Minnesota Rate Case

In October 2017, MERC initiated a rate proceeding with the MPUC to increase retail natural gas rates $12.6 million (5.05%). MERC's request reflects a 10.3% ROE and a common equity component average of 50.9%. The proposed retail natural gas rate increase is primarily driven by increased capital investments as well as general inflation. MERC is also requesting authority from the MPUC to continue the use of its currently authorized decoupling mechanism.

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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 reflect 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 currently authorized 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 during the second quarter of 2017.

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 the Tilden Mining Company (Tilden), under which Tilden will purchase electric power from UMERC for its iron ore mine for 20 years. The agreement also calls for UMERC to construct and operate approximately 180 MWs of natural gas-fired generation located 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 $265.7 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 in 2019 and should allow for the retirement of PIPP no later than 2020. Tilden will remain a customer of WE until this new generation begins commercial operation.

2015 Michigan Rate Order

Prior to the formation of UMERC, in October 2014, WPS initiated a rate proceeding with the MPSC. In April 2015, the MPSC issued a final written order for WPS, effective April 24, 2015, approving a settlement agreement. As a result of the formation of UMERC, the terms and conditions of this WPS rate order now apply to UMERC, including the deferrals described below. The order authorized a retail electric rate increase of $4.0 million to be implemented over three years to recover costs for the 2013 acquisition of the Fox Energy Center as well as other capital investments associated with the Crane Creek wind farm and environmental upgrades at generation plants. The rates reflected a 10.2% ROE and a common equity component average of 50.48%. The increase reflected the continued deferral of costs associated with the Fox Energy Center until the second anniversary of the order. The increase also reflected the deferral of Weston Unit 3 ReACT™ environmental project costs. On the second anniversary of the order, the Fox Energy Center costs deferral was discontinued and amortization of this deferral began, along with the amortization of the deferral associated with the termination of the Fox Energy Center tolling agreement. In the order, the MPSC also approved the deferral and amortization of the undepreciated book value of the retired plant associated with Pulliam Units 5 and 6 and Weston Unit 1 starting with the actual retirement date, June 1, 2015, and concluding by 2023. UMERC will not seek an increase to retail electric base rates that would become effective prior to January 1, 2018.

NOTE 20—NEW ACCOUNTING PRONOUNCEMENTS

Revenue Recognition

In May 2014, the FASB and the International Accounting Standards Board issued their joint revenue recognition standard, ASU 2014-09, Revenue from Contracts with Customers. Several amendments were issued subsequent to the standard to clarify the guidance. The core principle of the guidance is to recognize revenue in an amount that an entity is entitled to receive in exchange for goods and services. The guidance also requires additional disclosures about the nature, amount, timing, and uncertainty of revenues and the related cash flows arising from contracts with customers.

We intend to adopt this standard for interim and annual periods beginning January 1, 2018, as required, and plan to use the modified retrospective method of adoption. If applicable, this method requires a cumulative-effect adjustment to be recorded on the balance sheet as of the beginning of 2018, as if the standard had always been in effect. If applicable, disclosures in 2018 will include a

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reconciliation of results under the new revenue recognition guidance compared with what would have been reported in 2018 under the old revenue recognition guidance in order to help facilitate comparability with the prior periods.

We are finalizing our review of our contracts with customers and the related financial disclosures to evaluate the impact of the amended guidance on our existing revenue recognition policies and procedures. We consider tariff sales at our regulated utilities, excluding the revenue component related to alternative revenue programs, to be in the scope of the new standard. We have evaluated the nature of our operating revenues and do not expect that there will be a significant shift in the timing or pattern of revenue recognition. However, in our evaluation, we are also monitoring unresolved implementation issues for our industry. The final resolution of these issues could impact our current accounting policies and revenue recognition.

Recognition and Measurement of Financial Instruments

In January 2016, the FASB issued ASU 2016-01, Recognition and Measurement of Financial Assets and Liabilities. This guidance is effective for fiscal years and interim periods beginning after December 15, 2017, and will be recorded, if applicable, with a cumulative-effect adjustment to beginning retained earnings as of the beginning of the fiscal year in which the guidance is effective. This guidance requires equity investments, including other ownership interests such as partnerships, unincorporated joint ventures, and limited liability companies, to be measured at fair value with changes in fair value recognized in net income. It also simplifies the impairment assessment of equity investments without readily determinable fair values and amends certain disclosure requirements associated with the fair value of financial instruments. This ASU does not apply to investments accounted for under the equity method of accounting. We do not believe the adoption of this guidance will have a significant impact on our financial statements.

Leases

In February 2016, the FASB issued ASU 2016-02, Leases. This guidance is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018, and will be applied using a modified retrospective approach. The main provision of this ASU is that lessees will be required to recognize lease assets and lease liabilities for most leases, including those classified as operating leases under GAAP. We are currently assessing the effects this guidance may have on our financial statements.

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.

Classification of Certain Cash Receipts and Cash Payments

In August 2016, the FASB issued ASU 2016-15, Classification of Certain Cash Receipts and Cash Payments. This guidance is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017, and will be applied using a retrospective transition method. There are eight main provisions of this ASU for which current GAAP either is unclear or does not include specific guidance. We do not believe the adoption of this guidance will have a significant impact on our financial statements.

Restricted Cash

In November 2016, the FASB issued ASU 2016-18, Restricted Cash. This guidance is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017. Under this ASU, amounts generally described as restricted cash and restricted cash equivalents should be 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. We do not believe the adoption of this guidance will have a significant impact on our financial statements.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, the FASB issued ASU 2017-07, Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost. This guidance is effective for fiscal years, and interim periods within those fiscal years, beginning after

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December 15, 2017. Under this ASU, an employer is required to disaggregate the service cost component from the other components of the net benefit cost. The amendments provide explicit guidance on how to present the service cost component and the other components of the net benefit cost in the income statement and allow only the service cost component of the net benefit cost to be eligible for capitalization. The amendments should be applied retrospectively for the presentation of the service cost component and the other components of the net benefit cost in the income statement, and prospectively for the capitalization of the service cost component in assets. While we have not fully determined the impacts of the adoption of this standard, we expect that as a result of the application of accounting principles for rate regulated entities, a similar amount of net benefit cost (including non-service components), will be recognized in our financial statements consistent with the current ratemaking treatment. As a result, we believe the impacts of adoption will be limited to changes in classification of non-service costs in the income statements.

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

CORPORATE DEVELOPMENTS

The following discussion should be read in conjunction with the accompanying financial statements and related notes and our Annual Report on Form 10-K for the year ended December 31, 2016.

Introduction

We are a diversified holding company with natural gas and electric utility operations (serving customers in Wisconsin, Illinois, Michigan, and Minnesota), an approximately 60% equity ownership interest in ATC (a for-profit, electric transmission company regulated by the FERC and certain state regulatory commissions), and non-utility energy infrastructure operations through our We Power business and our recently acquired underground natural gas storage facilities in Michigan. For more information on the natural gas storage facilities, see Note 2, Acquisitions.

Corporate Strategy

Our goal is to continue to create long-term value for our shareholders and our customers by focusing on the following:

Reliability

We have made significant reliability-related investments in recent years, and plan to continue making significant capital investments to strengthen and modernize the reliability of our generation and distribution networks. Below are a few examples of reliability projects that are currently underway.

- 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 MWs of natural gas-fired generation located in the Upper Peninsula of Michigan. The new generation is expected to achieve commercial operation in 2019 and provide the region with affordable, reliable electricity that generates less emissions than PIPP. This should allow for the retirement of PIPP no later than 2020. For more information, see Note 19, Regulatory Environment.

- PGL continues to work on its SMP, which primarily involves replacing old cast and ductile iron gas pipes and facilities in the city of 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 SMRP, 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. WE, WPS, and WG 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 received approval from the PSCW to make changes at ERGS to enable the facility to burn coal from the Powder River Basin located in the western United States. The coal plant was originally designed to burn coal mined from the eastern United States. This project is creating flexibility and has enabled the plant to operate at lower costs, placing it in a better position to be called upon in the MISO Energy Markets, resulting in lower fuel costs for our customers.

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

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Financial Discipline

A strong adherence to financial discipline is essential to meeting our earnings projections and maintaining a strong balance sheet, stable cash flows, attractive dividends, 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, plant, and 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 a portion of a wind energy generation facility in Wisconsin.

- See Note 3, Dispositions, for information on the sale of ITF, the MCPP, certain assets of Wisvest, and Bostco's real estate holdings.

Our primary investment opportunities are in our regulated utility business and our investment in ATC. From 2017 to 2021, we expect capital contributions to ATC and ATC Holdco, LLC to be approximately $350 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 $1.4 billion inside the traditional ATC footprint and $300 million outside of the traditional ATC footprint.

Excluding ATC, we expect total capital expenditures for our regulated utility business to be approximately $12 billion from 2017 to 2021. Ongoing projects are discussed in more detail within Liquidity and Capital Resources.

We have developed and are executing a strategy to reshape our generation portfolio in order to 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. Subject to final review, we plan on retiring approximately 1,800 MWs of coal generation by 2020. See Note 4, Property, Plant, and Equipment, for information related to the planned retirement of our PIPP and jointly-owned Edgewater 4 generation units. In addition, we plan to retire our Pulliam power plant in Green Bay, WI, subject to the completion of a significant transmission project in that area. We are also reviewing retirements of additional coal-fueled generation units.

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, 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 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 in order 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.

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RESULTS OF OPERATIONS

THREE MONTHS ENDED SEPTEMBER 30, 2017

Consolidated Earnings

The following table compares our consolidated results for the third quarter of 2017 with the third quarter of 2016, including favorable or better, "B", and unfavorable or worse, "W", variances:

	Three Months Ended September 30		
(in millions, except per share data)	2017	2016	B (W)
Wisconsin	$279.7	$299.1	$(19.4)
Illinois	12.5	11.7	0.8
Other states	(3.1)	(1.0)	(2.1)
Non-utility energy infrastructure	103.4	93.7	9.7
Corporate and other	1.1	(4.5)	5.6
Total operating income	393.6	399.0	(5.4)
Equity in earnings of transmission affiliate	39.2	38.3	0.9
Other income, net	16.4	7.5	8.9
Interest expense	103.8	99.1	(4.7)
Income before income taxes	345.4	345.7	(0.3)
Income tax expense	129.7	128.4	(1.3)
Preferred stock dividends of subsidiary	0.3	0.3	—
Net income attributed to common shareholders	$215.4	$217.0	$(1.6)
Diluted earnings per share	$0.68	$0.68	$—

Earnings decreased $1.6 million during the third quarter of 2017, compared with the same quarter in 2016. The most significant factor impacting the decrease in earnings was a $19.4 million pre-tax ($11.6 million after tax) decrease in operating income at the Wisconsin segment. The decrease was primarily due to lower electric margins, driven by a decrease in sales volumes. Lower operating expenses partially offset the decrease in electric margins.

The decrease in operating income at the Wisconsin segment was partially offset by:

- A $9.7 million pre-tax ($5.8 million after tax) increase in operating income at the non-utility energy infrastructure segment, primarily driven by the inclusion of the operations of Bluewater following its acquisition on June 30, 2017.

- An $8.9 million pre-tax ($5.3 million after tax) increase in other income, net, due in part to an increase in gains on investments held in the rabbi trust and the quarter-over-quarter impact of expenses incurred in the third quarter of 2016 related to the disposition of certain non-utility real estate assets.

Non-GAAP Financial Measure

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 more meaningful basis for evaluating utility operations than operating revenues 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.

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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 the third quarter of 2017 and 2016 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

	Three Months Ended September 30		
(in millions)	2017	2016	B (W)
Electric revenues	$1,242.7	$1,320.4	$(77.7)
Fuel and purchased power	419.9	442.5	22.6
Total electric margins	822.8	877.9	(55.1)
Natural gas revenues	158.6	150.2	8.4
Cost of natural gas sold	71.4	65.5	(5.9)
Total natural gas margins	87.2	84.7	2.5
Total electric and natural gas margins	910.0	962.6	(52.6)
Other operation and maintenance	458.3	498.2	39.9
Depreciation and amortization	131.5	124.5	(7.0)
Property and revenue taxes	40.5	40.8	0.3
Operating income	$279.7	$299.1	$(19.4)

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

	Three Months Ended September 30		
(in millions)	2017	2016	B (W)
Operation and maintenance not included in line items below	$184.0	$204.8	$20.8
We Power [1]	129.6	129.6	—
Transmission [2]	108.8	107.0	(1.8)
Regulatory amortizations and other pass through expenses [3]	35.9	38.2	2.3
Earnings sharing mechanisms	—	18.6	18.6
Total other operation and maintenance	$458.3	$498.2	$39.9

(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 the three months ended September 30, 2017 and 2016, $129.0 million and $120.0 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, 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 the three months ended September 30, 2017 and 2016, $128.9 million and $127.7 million, respectively, of costs were billed by transmission providers to our electric utilities.

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

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

	Three Months Ended September 30 MWh (in thousands)		
Electric Sales Volumes	2017	2016	B (W)
Customer Class			
Residential	2,960.4	3,291.0	(330.6)
Small commercial and industrial *	3,440.6	3,604.8	(164.2)
Large commercial and industrial *	3,364.6	3,491.8	(127.2)
Other	39.8	36.4	3.4
Total retail *	9,805.4	10,424.0	(618.6)
Wholesale	977.8	1,006.9	(29.1)
Resale	2,484.8	2,544.4	(59.6)
Total sales in MWh *	13,268.0	13,975.3	(707.3)

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

	Three Months Ended September 30 Therms (in millions)		
Natural Gas Sales Volumes	2017	2016	B (W)
Customer Class			
Residential	59.0	54.3	4.7
Commercial and industrial	55.6	54.6	1.0
Total retail	114.6	108.9	5.7
Transport	275.7	260.3	15.4
Total sales in therms	390.3	369.2	21.1

	Three Months Ended September 30 Degree Days		
Weather	2017	2016	B(W)
WE and WG [1]			
Heating (118 normal)	72	27	45
Cooling (543 normal)	542	781	(239)
WPS [2]			
Heating (200 normal)	178	79	99
Cooling (363 normal)	315	426	(111)
UMERC [3]			
Heating (328 normal)	306	N/A	N/A
Cooling (243 normal)	186	N/A	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.

Electric Utility Margins

Electric utility margins at the Wisconsin segment decreased $55.1 million during the third quarter of 2017, compared with the same quarter in 2016. The significant factors impacting the lower electric utility margins were:

- A $46.5 million decrease related to lower sales volumes during the third quarter of 2017, primarily driven by cooler summer weather. As measured by cooling degree days, the quarter ended September 30, 2017, was 30.6% and 26.1% cooler than the same quarter in 2016 in the Milwaukee and Green Bay areas, respectively.

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- A $20.2 million quarter-over-quarter 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 margins were partially offset by $9.2 million of lower capacity payments to a counterparty during the third quarter of 2017.

Natural Gas Utility Margins

Natural gas utility margins at the Wisconsin segment increased $2.5 million during the third quarter of 2017, compared with the same quarter in 2016. The most significant factor impacting the higher natural gas utility margins was an increase in sales volumes, primarily driven by higher residential use per customer.

Operating Income

Operating income at the Wisconsin segment decreased $19.4 million during the third quarter of 2017, compared with the same quarter in 2016. This decrease was driven by the $52.6 million net decrease in margins discussed above, partially offset by $33.2 million of lower operating expenses (which include other operation and maintenance, depreciation and amortization, and property and revenues taxes).

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, which were due in part to synergy savings, were:

- An $18.9 million decrease in operation and maintenance expenses at our plants, primarily related to lower costs at the PIPP and the timing of planned outages and maintenance.

- An $18.6 million expense recorded in the third quarter of 2016 related to the earnings sharing mechanisms in place at WE and WG. See Note 19, Regulatory Environment, for more information.

- A $5.8 million decrease in electric and natural gas distribution expenses.

These decreases in operating expenses were partially offset by:

- A $7.3 million increase in benefit costs, primarily driven by higher stock-based compensation expense.

- A $7.0 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 an overall increase in utility plant in service.

Illinois Segment Contribution to Operating Income

	Three Months Ended September 30		
(in millions)	2017	2016	B (W)
Natural gas revenues	$187.2	$181.8	$5.4
Cost of natural gas sold	31.1	25.3	(5.8)
Total natural gas margins	156.1	156.5	(0.4)

Other operation and maintenance	100.8	105.9	5.1
Depreciation and amortization	38.9	33.5	(5.4)
Property and revenue taxes	3.9	5.4	1.5
Operating income	$12.5	$11.7	$0.8

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

	Three Months Ended September 30		
(in millions)	2017	2016	B (W)
Operation and maintenance not included in the line items below	$88.9	$90.7	$1.8
Riders *	11.5	14.5	3.0
Regulatory amortizations *	—	0.7	0.7
Other	0.4	—	(0.4)
Total other operation and maintenance	$100.8	$105.9	$5.1

* 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 sales volumes by customer class and weather statistics:

	Three Months Ended September 30 Therms (in millions)		
Natural Gas Sales Volumes	2017	2016	B (W)
Customer Class			
Residential	55.9	52.9	3.0
Commercial and industrial	14.0	15.1	(1.1)
Total retail	69.9	68.0	1.9
Transport	98.4	104.0	(5.6)
Total sales in therms	168.3	172.0	(3.7)

	Three Months Ended September 30 Degree Days		
Weather *	2017	2016	B (W)
Heating (81 Normal)	43	23	20

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

Natural Gas Utility Margins

Natural gas utility margins, net of the $3.0 million impact of the riders referenced in the table above, increased $2.6 million during the third quarter of 2017, compared with the same quarter in 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. 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.

Operating Income

Operating income at the Illinois segment increased $0.8 million during the third quarter of 2017, compared with the same quarter in 2016. This increase was due to the $2.6 million net increase in margins discussed above, partially offset by a $1.8 million increase in 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 increase in operating expenses was driven by higher depreciation expense at PGL due to continued capital investment in the SMP project.

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Other States Segment Contribution to Operating Income

	Three Months Ended September 30		
(in millions)	2017	2016	B (W)
Natural gas revenues	$49.8	$49.9	$(0.1)
Cost of natural gas sold	21.3	21.1	(0.2)
Total natural gas margins	28.5	28.8	(0.3)
Other operation and maintenance	21.6	21.2	(0.4)
Depreciation and amortization	6.3	5.2	(1.1)
Property and revenue taxes	3.7	3.4	(0.3)
Operating loss	$(3.1)	$(1.0)	$(2.1)

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

	Three Months Ended September 30		
(in millions)	2017	2016	B (W)
Operation and maintenance not included in line item below	$18.5	$18.6	$0.1
Regulatory amortizations and other pass through expenses *	3.1	2.6	(0.5)
Total other operation and maintenance	$21.6	$21.2	$(0.4)

* 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 sales volumes by customer class and weather statistics:

	Three Months Ended September 30 Therms (in millions)		
Natural Gas Sales Volumes	2017	2016	B (W)
Customer Class			
Residential	18.1	14.7	3.4
Commercial and industrial	18.5	10.1	8.4
Total retail	36.6	24.8	11.8
Transport	147.6	146.0	1.6
Total sales in therms	184.2	170.8	13.4

	Three Months Ended September 30 Degree Days		
Weather *	2017	2016	B (W)
Heating (173 Normal)	154	83	71

*

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

Operating Loss

The operating loss at the other states segment increased $2.1 million during the third quarter of 2017, compared to the same quarter last year. The increase was primarily driven by higher depreciation and amortization due to an increase in capital investment. See Note 19, Regulatory Environment, for more information regarding MERC's pending rate case.

Non-Utility Energy Infrastructure Segment Contribution to Operating Income

	Three Months Ended September 30		
(in millions)	2017	2016	B (W)
Operating income	$103.4	$93.7	$9.7

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Operating income at the non-utility energy infrastructure segment increased $9.7 million, or 10.4%, when compared to the third quarter of 2016. Bluewater, which was acquired on June 30, 2017, contributed $5.9 million to third quarter 2017 operating income. The remaining increase of $3.8 million was driven by higher revenues in connection with capital additions to the plants We Power owns and leases to WE. See Note 2, Acquisitions, for more information on the acquisition of Bluewater and Note 15, Segment Information, for information on the change in segment name.

Corporate and Other Segment Contribution to Operating Income

	Three Months Ended September 30		
(in millions)	2017	2016	B (W)
Operating income (loss)	$1.1	$(4.5)	$5.6

Operating income at the corporate and other segment increased $5.6 million, when compared to the third quarter of 2016, driven by costs related to the acquisition of Integrys incurred in 2016 and lower general corporate expenses in 2017.

Electric Transmission Segment Operations

	Three Months Ended September 30		
(in millions)	2017	2016	B (W)
Equity in earnings of transmission affiliate	$39.2	$38.3	$0.9

Consolidated Other Income, Net

	Three Months Ended September 30		
(in millions)	2017	2016	B (W)
AFUDC – Equity	$3.0	$6.7	$(3.7)
Other, net	13.4	0.8	12.6
Other income, net	$16.4	$7.5	$8.9

Other Income, net increased by $8.9 million when compared to the third quarter of 2016. The increase was due in part to a $3.0 million increase in gains on investments held in our rabbi trust during the third quarter of 2017, compared with the same period in 2016, in addition to expenses we incurred in the third quarter of 2016 related to the disposition of certain non-utility real estate assets. These increases were partially offset by lower AFUDC largely due to the ReACT™ emission control technology project at Weston Unit 3 going into service during the fourth quarter of 2016. See Note 3, Dispositions, for more information on our asset sales.

Consolidated Interest Expense

	Three Months Ended September 30		
(in millions)	2017	2016	B (W)
Interest expense	$103.8	$99.1	$(4.7)

Interest expense increased by $4.7 million, as compared with the third quarter of 2016. The increase was primarily due to higher debt levels in 2017 to fund continued capital investments and lower capitalized interest in 2017, primarily as a result of the completion of the ReACT™ emission control project in the fourth quarter of 2016.

Consolidated Income Tax Expense

	Three Months Ended September 30		
	2017	2016	B (W)
Effective tax rate	37.6%	37.1%	(0.5)%

Our effective tax rate increased by 0.5% when compared with the third quarter of 2016, primarily due to an increase in state income tax rates.

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NINE MONTHS ENDED SEPTEMBER 30, 2017

Consolidated Earnings

The following table compares our consolidated results for the nine months ended September 30, 2017 with the nine months ended September 30, 2016, including favorable or better, "B", and unfavorable or worse, "W", variances:

	Nine Months Ended September 30		
(in millions, except per share data)	2017	2016	B (W)
Wisconsin	$835.6	$841.3	$(5.7)
Illinois	209.3	171.3	38.0
Other states	35.0	33.1	1.9
Non-utility energy infrastructure	299.5	281.1	18.4
Corporate and other	(6.3)	(6.4)	0.1
Total operating income	1,373.1	1,320.4	52.7
Equity in earnings of transmission affiliate	122.9	107.7	15.2
Other income, net	45.2	72.6	(27.4)
Interest expense	310.4	300.1	(10.3)
Income before income taxes	1,230.8	1,200.6	30.2
Income tax expense	458.8	455.1	(3.7)
Preferred stock dividends of subsidiary	0.9	0.9	—
Net income attributed to common shareholders	$771.1	$744.6	$26.5
Diluted Earnings Per Share	$2.43	$2.35	$0.08

Earnings increased $26.5 million during the nine months ended September 30, 2017, compared with the same period in 2016. The significant factors impacting the increase in earnings were:

- A $38.0 million pre-tax ($22.8 million after tax) increase in operating income at the Illinois segment. The increase was driven by lower operating expenses and higher natural gas margins at PGL due to continued capital investment in the SMP project under its QIP rider.

- An $18.4 million pre-tax ($11.0 million after 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.

- A $15.2 million pre-tax ($9.1 million after tax) increase in earnings from our ownership interest in ATC. In 2016, ATC recognized lower earnings as a result of an ALJ recommendation related to the FERC ROE reviews. See Factors Affecting Results, Liquidity, and Capital Resources – Other Matters – American Transmission Company Allowed Return on Equity Complaints for more information.

- A 0.6% decrease in our effective tax rate also favorably impacted earnings. The decrease in our effective tax rate was in part due to the recognition of excess tax benefits related to share-based payments and favorable compensation expense during the nine months ended September 30, 2017.

These increases in earnings were partially offset by:

- A $27.4 million pre-tax ($16.4 million after tax) decrease in other income, net. The decrease was primarily driven by the period-over-period impact of the gains recognized in 2016 related to the repurchase of a portion of Integrys's 2006

Junior Notes and the sale of certain assets of Wisvest. See Note 3, Dispositions, for more information on the Wisvest sale.

- A $10.3 million pre-tax ($6.2 million after tax) increase in interest expense, driven by higher long-term debt levels and lower capitalized interest during 2017.

- A $5.7 million pre-tax ($3.4 million after tax) decrease in operating income at the Wisconsin segment. The decrease was primarily due to lower electric and natural gas margins, driven by a decrease in sales volumes. Lower operating expenses partially offset the decrease in margins.

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Non-GAAP Financial Measure

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 more meaningful basis for evaluating utility operations than operating revenues 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 the nine months ended September 30, 2017 and 2016 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

	Nine Months Ended September 30		
(in millions)	2017	2016	B (W)
Electric revenues	$3,448.7	$3,534.8	$(86.1)
Fuel and purchased power	1,115.4	1,121.9	6.5
Total electric margins	2,333.3	2,412.9	(79.6)
Natural gas revenues	867.9	820.4	47.5
Cost of natural gas sold	473.1	422.4	(50.7)
Total natural gas margins	394.8	398.0	(3.2)
Total electric and natural gas margins	2,728.1	2,810.9	(82.8)
Other operation and maintenance	1,379.9	1,477.3	97.4
Depreciation and amortization	391.1	370.1	(21.0)
Property and revenue taxes	121.5	122.2	0.7
Operating income	$835.6	$841.3	$(5.7)

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

	Nine Months Ended September 30		
(in millions)	2017	2016	B (W)
Operation and maintenance not included in line items below	$559.8	$637.6	$77.8

We Power [1]	384.3	385.5	1.2
Transmission [2]	318.8	318.6	(0.2)
Regulatory amortizations and other pass through expenses [3]	117.0	117.0	—
Earnings sharing mechanisms	—	18.6	18.6
Total other operation and maintenance	$1,379.9	$1,477.3	$97.4

(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 the nine months ended September 30, 2017 and 2016, $394.0 million and $383.5 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.

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(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 the nine months ended September 30, 2017 and 2016, $330.4 million and $371.6 million, respectively, of costs were billed by transmission providers to our electric utilities.

(3) 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 sales volumes by customer class and weather statistics:

	Nine Months Ended September 30 MWh (in thousands)		
Electric Sales Volumes	2017	2016	B (W)
Customer Class			
Residential	8,013.9	8,401.6	(387.7)
Small commercial and industrial *	9,746.8	9,974.0	(227.2)
Large commercial and industrial *	9,669.4	10,323.1	(653.7)
Other	126.9	124.0	2.9
Total retail *	27,557.0	28,822.7	(1,265.7)
Wholesale	2,854.4	2,760.3	94.1
Resale	6,002.5	6,638.9	(636.4)
Total sales in MWh *	36,413.9	38,221.9	(1,808.0)

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

	Nine Months Ended September 30 Therms (in millions)		
Natural Gas Sales Volumes	2017	2016	B (W)
Customer Class			
Residential	668.5	692.5	(24.0)
Commercial and industrial	421.6	426.3	(4.7)
Total retail	1,090.1	1,118.8	(28.7)
Transport	952.0	931.8	20.2
Total sales in therms	2,042.1	2,050.6	(8.5)

	Nine Months Ended September 30 Degree Days		
Weather	2017	2016	B(W)
WE and WG [1]			
Heating (4,333 normal)	3,669	4,058	(389)
Cooling (704 normal)	745	977	(232)
WPS [2]			
Heating (4,809 normal)	4,285	4,481	(196)

Cooling (494 normal)	440	568	(128)
UMERC [3]			
Heating (5,465 normal)	5,109	N/A	N/A
Cooling (322 normal)	233	N/A	N/A

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

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

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

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Electric Utility Margins

Electric utility margins at the Wisconsin segment decreased $79.6 million during the nine months ended September 30, 2017, compared with the same period in 2016. The significant factors impacting the lower electric utility margins were:

- A $71.2 million decrease related to lower sales volumes during the nine months ended September 30, 2017, primarily driven by unfavorable weather and lower overall retail use per customer. Cooler summer weather, warmer winter weather, and an additional day of sales during the same period in 2016 due to leap year contributed to the decrease. As measured by cooling degree days, the nine months ended September 30, 2017, were 23.7% and 22.5% cooler than the same period in 2016 in the Milwaukee and Green Bay areas, respectively. As measured by heating degree days, the nine months ended September 30, 2017, were 9.6% and 4.4% warmer than the same period in 2016 in the Milwaukee and Green Bay areas, respectively.

- A $31.0 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.

- A $4.5 million decrease in steam margins driven by the sale of the MCPP in April 2016. See Note 3, Dispositions, for more information.

These decreases in margins were partially offset by $27.2 million of lower capacity payments to a counterparty during the nine months ended September 30, 2017.

Natural Gas Utility Margins

Natural gas utility margins at the Wisconsin segment decreased $3.2 million during the nine months ended September 30, 2017, compared with the same period in 2016. The most significant factor impacting the lower natural gas utility margins were lower retail sales volumes, primarily driven by warmer winter weather. An additional day of sales during 2016 due to leap year also contributed to the decrease. The lower margins were partially offset by higher overall retail use per customer.

Operating Income

Operating income at the Wisconsin segment decreased $5.7 million during the nine months ended September 30, 2017, compared with the same period in 2016. This decrease was driven by the $82.8 million decrease in margins discussed above, partially offset by $77.1 million of lower operating expenses.

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, which were due in part to synergy savings, were:

- A $39.9 million decrease in operation and maintenance expenses at our plants, primarily related to the seasonal operation of the Pleasant Prairie Power Plant, lower costs at the PIPP, 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.

- A $20.9 million decrease in electric and natural gas distribution expenses.

- An $18.6 million expense recorded in the third quarter of 2016 related to the earnings sharing mechanisms in place at WE and WG. See Note 19, Regulatory Environment, for more information.

- A $10.1 million decrease in expenses related to an information technology project created to improve the billing, call center, and credit collection functions of the Integrys 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 WPS during 2017. The portion of these lower expenses related to the transfer are offset through higher depreciation and amortization, discussed below.

- A $6.5 million decrease in benefit costs.

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These decreases in operating expenses were partially offset by:

- A $21.0 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, the transfer of the information technology project to WPS during 2017, and an overall increase in utility plant in service.

- A $10.9 million gain on the sale of the MCPP, which was sold in April 2016. See Note 3, Dispositions, for more information on the sale of the MCPP.

Illinois Segment Contribution to Operating Income

	Nine Months Ended September 30		
(in millions)	2017	2016	B (W)
Natural gas revenues	$965.7	$853.1	$112.6
Cost of natural gas sold	302.9	228.8	(74.1)
Total natural gas margins	662.8	624.3	38.5
Other operation and maintenance	326.6	340.0	13.4
Depreciation and amortization	112.6	99.4	(13.2)
Property and revenue taxes	14.3	13.6	(0.7)
Operating income	$209.3	$171.3	$38.0

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

	Nine Months Ended September 30		
(in millions)	2017	2016	B (W)
Operation and maintenance not included in the line items below	$251.3	$284.7	$33.4
Riders *	73.2	50.3	(22.9)
Regulatory amortizations *	1.2	2.0	0.8
Other	0.9	3.0	2.1
Total other operation and maintenance	$326.6	$340.0	$13.4

* 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 sales volumes by customer class and weather statistics:

	Nine Months Ended September 30 Therms (in millions)		
Natural Gas Sales Volumes	2017	2016	B (W)
Customer Class			
Residential	595.7	623.1	(27.4)
Commercial and industrial	127.2	130.7	(3.5)
Total retail	722.9	753.8	(30.9)
Transport	571.2	606.6	(35.4)
Total sales in therms	1,294.1	1,360.4	(66.3)

	Nine Months Ended

	September 30 Degree Days		
Weather *	2017	2016	B (W)
Heating (3,947 Normal)	3,306	3,687	(381)

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

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Natural Gas Utility Margins

Natural gas utility margins, net of the $22.9 million impact of the riders referenced in the table above, increased $15.6 million during the nine months ended September 30, 2017, compared with the same period in 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. 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.

Operating Income

Operating income at the Illinois segment increased $38.0 million during the nine months ended September 30, 2017, compared with the same period in 2016. This increase was due to the $15.6 million net increase in margins discussed above and a $22.4 million decrease in operating expenses, net of the impact of the riders referenced in the table above. The significant factors impacting the decrease in operating expenses were:

- A $14.1 million decrease in benefit costs driven by lower pension costs.

- A $7.9 million decrease driven by the residual impact of the warmer weather this past winter leading to reduced need for repair and maintenance activity.

These decreases were partially offset by higher depreciation expense at PGL due to continued capital investment in the SMP project.

Other States Segment Contribution to Operating Income

	Nine Months Ended September 30		
(in millions)	2017	2016	B (W)
Natural gas revenues	$273.4	$262.3	$11.1
Cost of natural gas sold	135.1	123.1	(12.0)
Total natural gas margins	138.3	139.2	(0.9)
Other operation and maintenance	73.2	80.6	7.4
Depreciation and amortization	18.4	15.5	(2.9)
Property and revenue taxes	11.7	10.0	(1.7)
Operating income	$35.0	$33.1	$1.9

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

	Nine Months Ended September 30		
(in millions)	2017	2016	B (W)
Operation and maintenance not included in line item below	$56.3	$63.6	$7.3
Regulatory amortizations and other pass through expenses *	16.9	17.0	0.1
Total other operation and maintenance	$73.2	$80.6	$7.4

* 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 sales volumes by customer class and weather statistics:

	Nine Months Ended September 30 Therms (in millions)		
Natural Gas Sales Volumes	2017	2016	B (W)
Customer Class			
Residential	191.5	198.4	(6.9)
Commercial and industrial	130.1	125.5	4.6
Total retail	321.6	323.9	(2.3)
Transport	506.6	530.2	(23.6)
Total sales in therms	828.2	854.1	(25.9)

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	Nine Months Ended September 30 Degree Days		
Weather *	2017	2016	B (W)
Heating (4,589 Normal)	4,064	4,162	(98)

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

Operating Income

Operating income at the other states segment increased $1.9 million during the nine months ended September 30, 2017, compared with the same period in 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

	Nine Months Ended September 30		
(in millions)	2017	2016	B (W)
Operating income	$299.5	$281.1	$18.4

Operating income at the non-utility energy infrastructure segment increased $18.4 million, or 6.5%, when compared with the nine months ended September 30, 2016. Higher revenues in connection with capital additions to the plants We Power owns and leases to WE drove $12.5 million of the increase. In addition, Bluewater, which was acquired on June 30, 2017, contributed $5.9 million to 2017 operating income. See Note 2, Acquisitions, for more information on the acquisition of Bluewater and Note 15, Segment Information, for information on the change in segment name.

Corporate and Other Segment Contribution to Operating Income

	Nine Months Ended September 30		
(in millions)	2017	2016	B (W)
Operating loss	$(6.3)	$(6.4)	$0.1

Electric Transmission Segment Operations

	Nine Months Ended September 30		
(in millions)	2017	2016	B (W)
Equity in earnings of transmission affiliate	$122.9	$107.7	$15.2

Equity in earnings of transmission affiliate increased $15.2 million, or 14.1%, when compared with the nine months ended September 30, 2016. Lower earnings during the nine months ended September 30, 2016, were the result of an ALJ recommendation related to the FERC ROE reviews. 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

	Nine Months Ended September 30		
(in millions)	2017	2016	B (W)
AFUDC – Equity	$8.3	$20.7	$(12.4)
Gain on repurchase of notes	—	23.6	(23.6)
Gain on sale of certain assets of Wisvest	—	19.6	(19.6)
Other, net	36.9	8.7	28.2
Other income, net	$45.2	$72.6	$(27.4)

Other income, net decreased by $27.4 million when compared with the nine months ended September 30, 2016. The decrease was primarily due to the $23.6 million gain on the repurchase of a portion of Integrys's 2006 Junior Notes at a discount in February 2016,

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a $19.6 million gain recorded in April 2016 from the sale of the chilled water generation and distribution assets of Wisvest, and lower AFUDC largely due to the ReACT™ emission control technology project at Weston Unit 3 going into service during the fourth quarter of 2016. Partially offsetting these decreases were higher gains on investments held in our rabbi trust during the nine months ended September 30, 2017, compared with the same period in 2016. See Note 3, Dispositions, for more information on our asset sales.

Consolidated Interest Expense

	Nine Months Ended September 30		
(in millions)	2017	2016	B (W)
Interest expense	$310.4	$300.1	$(10.3)

Interest expense increased by $10.3 million, as compared with the nine months ended September 30, 2016. The increase was primarily due to higher debt levels in 2017 to fund continued capital investments and lower capitalized interest in the nine months ended September 30, 2017, primarily as a result of the completion of the ReACT™ emission control project in the fourth quarter of 2016.

Consolidated Income Tax Expense

	Nine Months Ended September 30		
	2017	2016	B (W)
Effective tax rate	37.3%	37.9%	0.6%

Our effective tax rate decreased by 0.6% when compared with the nine months ended September 30, 2016, in part due to the recognition of excess tax benefits related to share-based payments and favorable compensation expense during the nine months ended September 30, 2017. See Note 5, Common Equity, for more information on the excess tax benefits related to share-based payments. We expect our 2017 annual effective tax rate to be between 37.0% and 38.0%.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows

The following table summarizes our cash flows during the nine months ended September 30:

(in millions)	2017	2016	Change in 2017 Over 2016
Cash provided by (used in):			
Operating activities	$1,746.7	$1,721.9	$24.8
Investing activities	(1,552.0)	(841.6)	(710.4)
Financing activities	(214.1)	(905.1)	691.0

Operating Activities

Net cash provided by operating activities increased $24.8 million during the nine months ended September 30, 2017, compared with the same period in 2016, driven by:

- A $139.9 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 20.5% during the nine months ended September 30, 2017, compared with the same period in 2016.

- A $134.0 million increase in cash from lower payments for operating and maintenance costs. During the nine months ended September 30, 2017, our payments related to transmission, electric generation, electric and natural gas distribution, and employee benefits decreased.

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

- A $140.4 million decrease in cash resulting from higher payments for natural gas and fuel and purchased power, primarily due to higher commodity prices during the nine months ended September 30, 2017, compared with the same period in 2016.

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- A $91.9 million increase in contributions and payments to our pension and OPEB plans during the nine months ended September 30, 2017, compared with the same period in 2016.

Investing Activities

Net cash used in investing activities increased $710.4 million during the nine months ended September 30, 2017, compared with the same period in 2016, driven by:

- A $309.1 million increase in cash paid for capital expenditures during the nine months ended September 30, 2017, compared with the same period in 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 $138.5 million decrease in the proceeds received from the sale of assets and businesses during the nine months ended September 30, 2017, compared with the same period in 2016. See Note 3, Dispositions, for more information.

- A $36.2 million increase in our capital contributions to ATC during the nine months ended September 30, 2017, compared with the same period in 2016, due to the continued investment in equipment and facilities by ATC to improve reliability. The refunds and reserves resulting from the ATC ROE complaints filed with the FERC also contributed to the increase in our capital contributions. See Factors Affecting Results, Liquidity, and Capital Resources – Other Matters – American Transmission Company Allowed Return on Equity Complaints for more information on these ATC ROE complaints.

Capital Expenditures

Capital expenditures by segment for the nine months ended September 30 were as follows:

Reportable Segment (in millions)	2017	2016	Change in 2017 Over 2016
Wisconsin	$764.0	$644.5	$119.5
Illinois	356.8	204.3	152.5
Other states	52.9	42.7	10.2
Non-utility energy infrastructure	19.1	39.5	(20.4)
Corporate and other	116.4	69.1	47.3
Total capital expenditures	$1,309.2	$1,000.1	$309.1

The increase in cash paid for capital expenditures at the Wisconsin segment during the nine months ended September 30, 2017, compared with the same period in 2016, was driven by upgrades to our electric and natural gas distribution systems, including meter and main replacement projects, WPS's SMRP, and various projects at the OCPP. These increases in capital expenditures were partially offset by reduced construction activity at WPS since the ReACT™ emission control technology project at Weston Unit 3 was completed in 2016. In addition, WPS had lower expenditures for the upgrades to the combustion turbine units at the Fox Energy Center, which were completed in June 2017.

The increase in cash paid for capital expenditures at the Illinois segment during the nine months ended September 30, 2017, compared with the same period in 2016, was driven by increased construction activity related to PGL's SMP and a project to relocate one of PGL's service facilities.

The decrease in cash paid for capital expenditures at the non-utility energy infrastructure segment during the nine months ended September 30, 2017, compared with the same period in 2016, was driven by reduced construction activity during 2017 for We Power's fuel flexibility project at the Oak Creek Expansion units.

The increase in cash paid for capital expenditures at the corporate and other segment during the nine months ended September 30, 2017, compared with the same period in 2016, was primarily driven by a project to implement a new enterprise resource planning system.

See Capital Requirements – Significant Capital Projects for more information.

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Financing Activities

Net cash used in financing activities decreased $691.0 million during the nine months ended September 30, 2017, compared with the same period in 2016, driven by:

- A $438.9 million net increase in cash due to $133.3 million of net borrowings of commercial paper during the nine months ended September 30, 2017, compared with $305.6 million of net repayments of commercial paper during the same period in 2016.

- A $226.6 million decrease in cash used for the repayment of long-term debt during the nine months ended September 30, 2017, compared with the same period in 2016. In February 2016, we repurchased a portion of Integrys's 2006 Junior Notes at a discount.

- A $45.0 million decrease in cash used to purchase shares of our common stock during the nine months ended September 30, 2017, compared with the same period in 2016, to satisfy requirements of our stock-based compensation plans.

These decreases in net cash used in financing activities were partially offset by a $23.8 million increase in dividends paid on common stock during the nine months ended September 30, 2017, compared with the same period in 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 6, Short-Term Debt and Lines of Credit, and Note 7, 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.

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 6, Short-Term Debt and Lines of Credit, for more information about these credit facilities.

The following table shows our capitalization structure as of September 30, 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:

(in millions)	Actual	Adjusted
Common equity	$9,195.3	$9,445.3
Preferred stock of subsidiary	30.4	30.4
Long-term debt (including current portion)	9,495.1	9,245.1
Short-term debt	993.5	993.5
Total capitalization	$19,714.3	$19,714.3
Total debt	$10,488.6	$10,238.6
Ratio of debt to total capitalization	53.2 %	51.9 %

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Included in long-term debt on our balance sheet as of September 30, 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 the rating agency 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.

As of September 30, 2017, WE was the obligor under a series of tax-exempt pollution control refunding bonds with an outstanding principal amount of $80.0 million. In August 2009, WE terminated a letter of credit that provided credit and liquidity support for the bonds, which resulted in a mandatory tender of the bonds. WE purchased the bonds at par plus accrued interest to the date of purchase. As of September 30, 2017, the repurchased bonds were still outstanding but are not reported in our long-term debt since they are held by WE. Depending on market conditions and other factors, WE may change the method used to determine the interest rate on this bond series and have it remarketed to third parties.

Working Capital

As of September 30, 2017, our current liabilities exceeded our current assets by $1,202.8 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 July 2017, Moody's downgraded the ratings of WE (senior unsecured), WPS (senior unsecured), WG (senior unsecured), and Elm Road Generating Station Supercritical, LLC (senior secured) to A2 from A1. Moody's affirmed the commercial paper ratings of WE (P-1), WPS (P-1), and WG (P-1). Moody's also affirmed the ratings of WEC Energy Group (senior unsecured, A3), Wisconsin Energy Capital Corporation (senior unsecured, A3), and Integrys (senior unsecured, A3), but changed the rating outlook for these companies from stable to negative. We do not believe the change in ratings and rating outlook will have a material impact on 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.

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Capital Requirements

Significant Capital Projects

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

(in millions)	2017	2018	2019
Wisconsin	$1,111.2	$1,392.8	$1,126.3
Illinois	570.6	619.7	620.2
Other states	88.3	97.2	114.2
Non-utility energy infrastructure	279.3	283.1	60.8
Corporate and other	157.7	72.4	49.6
Total	$2,207.1	$2,465.2	$1,971.1

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 $300 million between 2017 and 2021 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.

In connection with the formation of UMERC, we entered into an agreement with Tilden Mining Company under which it will purchase electric power from UMERC for 20 years. The agreement calls for UMERC to construct and operate approximately 180 MW of natural gas-fired generation located in the Upper Peninsula of Michigan. The estimated cost of this project is $265 million ($275 million including AFUDC). See Note 19, Regulatory Environment, for more information about UMERC and this new generation.

On June 30, 2017, we completed the acquisition of Bluewater for $226 million. Bluewater owns natural gas storage facilities in Michigan that will provide approximately one-third of the current storage needs for our Wisconsin natural gas utilities. In addition, we incurred approximately $5 million of acquisition related costs. See Note 2, Acquisitions, for more information on this transaction.

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 2019 is between $280 million and $300 million. See Note 19, Regulatory Environment, for more information on the SMP.

We expect to provide total capital contributions to ATC (not included in the above table) of approximately $226 million from 2017 through 2019.

Common Stock Dividends

Our current quarterly dividend rate is $0.52 per share, which equates to an annual dividend of $2.08 per share. For information related to our most recent common stock dividend declared, see Note 5, Common Equity.

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 6, Short-Term Debt and Lines of Credit, Note 11, Guarantees, and Note 16, Variable Interest Entities.

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Contractual Obligations

For additional information about our commitments, see Contractual Obligations in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Resources and Requirements in our 2016 Annual Report on Form 10-K.

FACTORS AFFECTING RESULTS, LIQUIDITY, AND CAPITAL RESOURCES

The following is a discussion of certain factors that may affect our results of operations, liquidity, and capital resources. The following discussion should be read together with the information in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity, and Capital Resources in our 2016 Annual Report on Form 10-K, which provides a more complete discussion of factors affecting us, including market risks and other significant risks, industry restructuring, environmental matters, critical accounting policies and estimates, and other matters.

Market Risks and Other Significant Risks

We are exposed to market and other significant risks as a result of the nature of our businesses and the environments in which those businesses operate. These risks include, but are not limited to, the regulatory recovery risk described below. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity, and Capital Resources – Market Risks and Other Significant Risks in our 2016 Annual Report on Form 10-K for a discussion of other significant risks applicable to us.

Regulatory Recovery

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. 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.

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, is currently estimated to be $342 million. In September 2017, the PSCW approved an extension of this deferral through 2019 as part of a settlement agreement. See Note 19, 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, 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 September 30, 2017, 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 2017, PGL filed its 2016 reconciliation with the ICC, which, along with the 2015 reconciliation, is still pending. For PGL's 2014 reconciliation, the ICC staff and the Illinois Attorney General's office held an evidentiary hearing in September 2017, and we expect to receive an order related to the 2014 reconciliation in 2017. As of September 30, 2017, 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 19, Regulatory Environment, for more information regarding recent and pending rate proceedings, orders, and investigations involving our utilities.

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Environmental Matters

See Note 17, 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

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 a final order related to this complaint affirming the use of the ROEs 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 13, 2013, through February 11, 2015. The refunds 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.

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.

The decrease in ATC's ROE resulting from the FERC's final order issued in September 2016 will continue to have a negative impact on our equity earnings and distributions from ATC.

Critical Accounting Policies and Estimates

We have reviewed our critical accounting policies and considered whether any new critical accounting estimates or other significant changes to our accounting policies require additional disclosures. We have found that the disclosures made in our 2016 Annual Report on Form 10-K are still current and that there have been no significant changes, except as follows:

Goodwill Impairment

We completed our annual goodwill impairment tests for all of our reporting units that carried a goodwill balance as of July 1, 2017. No impairments were recorded as a result of these tests. For our Bluewater reporting unit, we assumed fair value equaled carrying value since Bluewater was acquired on June 30, 2017. For all of our other reporting units, the fair values calculated in step one of the test were greater than their carrying values. The fair values for these 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 fair value of a reporting unit. Since all of our reporting units 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

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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 other than Bluewater, fair value exceeded carrying value by over 50%. For Bluewater, we assumed fair value equaled carrying value since we acquired Bluewater on June 30, 2017. 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, 2017:

(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	7.3	0.2	%
Total goodwill	$3,053.5	100.0	%

See Note 13, Goodwill, for more information.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

There have been no material changes related to market risk from the disclosures presented in our Annual Report on Form 10-K for the year ended December 31, 2016. In addition to the Form 10-K disclosures, see Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity, and Capital Resources – Market Risks and Other Significant Risks in Item 2 of Part I of this report, as well as Note 9, Fair Value Measurements, Note 10, Derivative Instruments, and Note 11, Guarantees, in this report for information concerning our market risk exposures.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

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

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting (as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) during the third quarter of 2017 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

The following should be read in conjunction with Item 3. Legal Proceedings in Part I of our 2016 Annual Report on Form 10-K. See Note 17, Commitments and Contingencies, and Note 19, Regulatory Environment, in this report for more information on material legal proceedings and matters related to us and our subsidiaries.

In addition to those legal proceedings referenced above and discussed 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 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

Sheboygan River Matter

We were contacted by the United States Department of Justice in March 2016 to commence discussions between WPS and the federal natural resource trustees to resolve WPS's alleged liability for natural resources damages (NRD) in the Sheboygan River related to the former Camp Marina manufactured gas plant site. WPS was originally notified about this claim in September 2012, but the WDNR chose not to be a party to the NRD claim negotiation in February 2014. However, the National Oceanic and Atmospheric Administration has co-equal trusteeship with the WDNR over the impacted Sheboygan River natural resources and is now pursuing the NRD claim. Substantial remediation of the uplands at the legacy Sheboygan Camp Marina manufactured gas plant site has already occurred. We agreed to settle this matter, subject to the approval of the United States District Court for the Eastern District of Wisconsin. The terms of the settlement, if approved, will not have a material impact on our financial statements.

ITEM 1A. RISK FACTORS

There were no material changes from the risk factors presented in our Annual Report on Form 10-K for the year ended December 31, 2016. See Item 1A. Risk Factors in Part I of our 2016 Annual Report on Form 10-K for a discussion of certain risk factors applicable to us.

ITEM 5. OTHER INFORMATION

On October 12, 2017, we reported that Allen L. Leverett, Chief Executive Officer of WEC Energy Group, had been hospitalized and was receiving medical treatment for a stroke. Mr. Leverett has since been released from the hospital and is making progress in his recovery and rehabilitation work. Gale E. Klappa continues to serve as Chairman of the Board and Interim Chief Executive Officer of the Company, and has executed the certifications attached as exhibits to this Form 10-Q in such capacity.

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ITEM 6. EXHIBITS

Number	Exhibit
10	Material Contracts
10.1	Letter Agreement by and between WEC Energy Group, Inc. and Margaret C. Kelsey, dated as of July 19, 2017.
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

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

WEC ENERGY GROUP, INC.
(Registrant)

/s/ WILLIAM J. GUC
Date: November 3, 2017 William J. Guc
Vice President and Controller

(Duly Authorized Officer and Chief Accounting Officer)