INTEGRYS HOLDING, INC.

FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 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
IES	Integrys Energy Services, Inc.
ITF	Integrys Transportation Fuels, LLC
MERC	Minnesota Energy Resources Corporation
MGU	Michigan Gas Utilities Corporation
NSG	North Shore Gas Company
PDL	WPS Power Development, LLC
PELLC	Peoples Energy, LLC
PGL	The Peoples Gas Light and Coke Company
UMERC	Upper Michigan Energy Resources Corporation
WBS	WEC Business Services LLC
WEC Energy Group	WEC Energy Group, Inc. (previously known as Wisconsin Energy Corporation)
WE	Wisconsin Electric Power Company
WG	Wisconsin Gas LLC
WPS	Wisconsin Public Service Corporation
WPSI	WPS Investments, LLC
WRPC	Wisconsin River Power Company

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

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

Environmental Terms	
CAA	Clean Air Act
CO_2	Carbon Dioxide
CPP	Clean Power Plan
GHG	Greenhouse Gas
NAAQS	National Ambient Air Quality Standards
NOV	Notice of Violation
SO_2	Sulfur Dioxide

Measurements

Dth	Dekatherm
MW	Megawatt
MWh	Megawatt-hour

Other Terms and Abbreviations

AIA	Affiliated Interest Agreement
CNG	Compressed Natural Gas
Compensation Committee	Compensation Committee of the Board of Directors of WEC Energy Group, Inc.
D.C. Circuit Court of Appeals	United States Court of Appeals for the District of Columbia Circuit
FTRs	Financial Transmission Rights
Merger Agreement	Agreement and Plan of Merger, dated as of June 22, 2014, between Integrys Energy Group, Inc. and Wisconsin Energy Corporation
MISO	Midcontinent Independent System Operator, Inc.
MISO Energy Markets	MISO Energy and Operating Reserves Market
QIP	Qualifying Infrastructure Plant
ROE	Return on Equity
SMP	Natural Gas System Modernization Program
Supreme Court	United States Supreme Court
Tax Legislation	Tax Cuts and Jobs Act of 2017

FINANCIAL STATEMENTS AND NOTES

A. INDEPENDENT AUDITORS' REPORT

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

Milwaukee, Wisconsin

We have audited the accompanying consolidated financial statements of Integrys Holding, Inc. and its subsidiaries (the "Company"), which comprise the consolidated balance sheets and the consolidated statements of capitalization as of December 31, 2017 and 2016, and the related consolidated income statements, consolidated statements of comprehensive income, equity, and cash flows for the three years ended December 31, 2017, and the related notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

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

Auditors' Responsibility

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

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

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

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Integrys Holding, Inc. and its subsidiaries as of December 31, 2017 and 2016, and the results of their operations and their cash flows for the three years ended December 31, 2017, in accordance with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
March 26, 2018

INTEGRYS HOLDING, INC.

B. CONSOLIDATED INCOME STATEMENTS

Year Ended December 31 *(in millions)*	**2017**	**2016**	**2015**
Operating revenues	**$ 3,264.9**	$ 3,088.9	$ 3,219.1
Operating expenses			
Cost of sales	**1,228.1**	1,080.7	1,300.3
Other operation and maintenance	**1,017.6**	1,156.9	1,064.6
Depreciation and amortization	**320.3**	283.5	292.5
Property and revenue taxes	**75.1**	71.8	72.9
Merger costs	**—**	—	86.9
Impairment losses	**—**	—	47.3
Total operating expenses	**2,641.1**	2,592.9	2,864.5
Operating income	**623.8**	496.0	354.6
Equity in earnings of transmission affiliate	**93.8**	82.2	70.6
Other income, net	**38.3**	52.1	29.1
Interest expense	**144.0**	134.2	151.1
Other (expense) income	**(11.9)**	0.1	(51.4)
Income before income taxes	**611.9**	496.1	303.2
Income tax expense	**221.5**	196.7	132.0
Net income from continuing operations	**390.4**	299.4	171.2
Discontinued operations, net of tax	**—**	—	(0.8)
Net income	**390.4**	299.4	170.4
Preferred stock dividends of subsidiary	**—**	—	(2.7)
Net income attributed to common shareholder	**$ 390.4**	$ 299.4	$ 167.7

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

INTEGRYS HOLDING, INC.

C. CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31 *(in millions)*	2017	2016	2015
Net income	**$ 390.4**	$ 299.4	$ 170.4
Other comprehensive income (loss), net of tax			
Derivatives accounted for as cash flow hedges			
Reclassification of net losses to net income, net of tax	**0.5**	0.6	0.7
Defined benefit plans			
Pension and OPEB adjustments arising during the period, net of tax of $0.7, $0.1, and $(2.6), respectively	**1.0**	0.2	(3.1)
Amortization of pension and OPEB costs included in net periodic benefit cost, net of tax of $3.0, $2.9, and $1.4, respectively	**4.3**	4.3	1.6
Defined benefit plans, net	**5.3**	4.5	(1.5)
Other comprehensive income (loss), net of tax	**5.8**	5.1	(0.8)
Comprehensive income	**396.2**	304.5	169.6
Preferred stock dividends of subsidiary	**—**	—	(2.7)
Comprehensive income attributed to common shareholder	**$ 396.2**	$ 304.5	$ 166.9

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

INTEGRYS HOLDING, INC.

D. CONSOLIDATED BALANCE SHEETS

At December 31 ***(in millions, except share and per share data)***	**2017**	**2016**
Assets		
Current assets		
Cash and cash equivalents	**$ 19.3**	$ 12.0
Accounts receivable and unbilled revenues, net of reserves of $84.8 and $47.6, respectively	**668.1**	618.1
Receivables from related parties	**15.6**	14.0
Materials, supplies, and inventories	**238.0**	270.1
Note receivable from related party	**278.2**	—
Prepaid taxes	**57.5**	51.7
Other	**57.6**	61.3
Current assets	**1,334.3**	1,027.2
Long-term assets		
Property, plant, and equipment, net of accumulated depreciation of $3,442.5 and $3,315.5, respectively	**8,460.4**	7,779.9
Regulatory assets	**1,385.7**	1,535.1
Equity investment in transmission affiliate	**621.1**	600.2
Goodwill	**635.8**	635.8
Other	**333.5**	250.6
Long-term assets	**11,436.5**	10,801.6
Total assets	**$ 12,770.8**	$ 11,828.8
Liabilities and Equity		
Current liabilities		
Short-term debt	**$ 533.0**	$ 228.0
Current portion of long-term debt	**255.0**	125.0
Accounts payable	**435.4**	482.1
Payables to related parties	**66.2**	48.3
Note payable to related party	**—**	42.0
Accrued taxes	**107.9**	64.7
Other	**243.2**	200.7
Current liabilities	**1,640.7**	1,190.8
Long-term liabilities		
Long-term debt	**2,994.6**	2,940.7
Deferred income taxes	**1,146.9**	1,948.0
Deferred investment tax credits	**57.8**	59.6
Regulatory liabilities	**1,479.2**	507.7
Environmental remediation liabilities	**557.7**	578.4
Pension and OPEB obligations	**209.8**	300.9
AROs	**501.7**	492.7
Other	**178.2**	181.6
Long-term liabilities	**7,125.9**	7,009.6
Commitments and contingencies (Note 21)		
Common stock – $0.01 par value; 10,000 shares authorized, 1,020 shares issued and outstanding	**—**	—
Additional paid in capital	**2,664.9**	2,685.3
Retained earnings	**1,356.8**	966.4
Accumulated other comprehensive loss	**(17.5)**	(23.3)
Total common shareholder's equity	**4,004.2**	3,628.4
Total liabilities and equity	**$ 12,770.8**	$ 11,828.8

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

INTEGRYS HOLDING, INC.

E. CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31 *(in millions)*	**2017**	**2016**	**2015**
Operating activities			
Net income	**$ 390.4**	$ 299.4	$ 170.4
Reconciliation to cash provided by operating activities			
Depreciation and amortization	**320.3**	283.5	299.6
Deferred income taxes and investment tax credits, net	**237.5**	257.0	159.9
Contributions and payments related to pension and OPEB plans	**(70.2)**	(2.4)	(16.4)
Equity income in transmission affiliate, net of distributions	**(9.3)**	(26.0)	(6.9)
Cash paid for benefit-related transfers with WBS	**(36.7)**	(31.2)	—
Impairment losses	**—**	—	47.3
Change in –			
Accounts receivable and unbilled revenues	**(34.1)**	(124.3)	227.9
Materials, supplies, and inventories	**32.7**	58.9	(13.8)
Prepaid taxes	**(5.8)**	70.5	13.9
Other current assets	**6.4**	1.5	(17.2)
Accounts payable	**(10.3)**	(8.6)	(32.4)
Accrued taxes	**44.3**	25.1	(16.1)
Other current liabilities	**37.2**	(21.6)	45.5
Other, net	**(73.4)**	22.5	(57.8)
Net cash provided by operating activities	**829.0**	804.3	803.9
Investing activities			
Capital expenditures	**(960.0)**	(665.6)	(887.9)
Capital contributions to transmission affiliate	**(34.1)**	(23.9)	(6.8)
Proceeds from the sale of assets and businesses	**4.3**	99.7	86.9
Proceeds from assets transferred to WBS	**25.5**	7.6	—
Payments for assets transferred from WBS	**(46.1)**	(95.0)	—
Withdrawal of restricted cash from Rabbi trust for qualifying payments	**19.5**	26.6	15.5
Rabbi trust funding related to change in control	**—**	—	(14.3)
Short-term notes receivable from related parties, net	**(278.2)**	14.8	—
Cash proceeds from corporate owned life insurance policies	**—**	—	17.3
Other, net	**3.5**	(2.6)	(6.1)
Net cash used in investing activities	**(1,265.6)**	(638.4)	(795.4)
Financing activities			
Issuance of common stock to parent	**—**	66.4	—
Purchase of common stock	**—**	—	(23.9)
Dividends paid on common stock	**—**	—	(125.4)
Redemption of WPS preferred stock	**—**	—	(52.7)
Retirement of long-term debt	**(125.0)**	(278.6)	(130.1)
Issuance of long-term debt	**310.0**	200.0	250.0
Repayment of loan	**—**	(28.6)	—
Change in short-term debt	**305.0**	(77.5)	(12.1)
Short-term notes payable to related parties, net	**(42.0)**	(53.1)	95.1
Other, net	**(4.1)**	(1.9)	(8.0)
Net cash provided by (used in) financing activities	**443.9**	(173.3)	(7.1)
Net change in cash and cash equivalents	**7.3**	(7.4)	1.4
Cash and cash equivalents at beginning of year	**12.0**	19.4	18.0
Cash and cash equivalents at end of year	**$ 19.3**	$ 12.0	$ 19.4

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

INTEGRYS HOLDING, INC.

F. CONSOLIDATED STATEMENTS OF EQUITY

(in millions, except per share data)	Shares in Deferred Compensation Trust	Common Stock	Additional Paid-In Capital	Retained Earnings	Accumulated Other Compre-hensive Income (Loss)	Total Common Share-holder's Equity	Preferred Stock of Subsidiary	Total Equity
Balance at December 31, 2014	$ (20.9)	$ 80.0	$ 2,642.2	$ 626.0	$ (27.6)	$ 3,299.7	$ 51.1	$ 3,350.8
Net income attributed to common shareholder	—	—	—	167.7	—	167.7	—	167.7
Other comprehensive loss	—	—	—	—	(0.8)	(0.8)	—	(0.8)
Stock-based compensation	—	—	(6.3)	(0.2)	—	(6.5)	—	(6.5)
Dividends on common stock (dividends per common share of $1.58)	—	—	—	(125.4)	—	(125.4)	—	(125.4)
Redemption of WPS preferred stock	—	—	(1.6)	—	—	(1.6)	(51.1)	(52.7)
Other	20.9	(80.0)	57.4	(1.1)	—	(2.8)	—	(2.8)
Balance at December 31, 2015	$ —	$ —	$ 2,691.7	$ 667.0	$ (28.4)	$ 3,330.3	$ —	$ 3,330.3
Net income attributed to common shareholder	—	—	—	299.4	—	299.4	—	299.4
Other comprehensive income	—	—	—	—	5.1	5.1	—	5.1
Issuance of common stock to parent	—	—	66.4	—	—	66.4	—	66.4
Non-cash equity transfer of our ownership in WBS to WEC Energy Group	—	—	(73.0)	—	—	(73.0)	—	(73.0)
Other	—	—	0.2	—	—	0.2	—	0.2
Balance at December 31, 2016	$ —	$ —	$ 2,685.3	$ 966.4	$ (23.3)	$ 3,628.4	$ —	$ 3,628.4
Net income attributed to common shareholder	**—**	**—**	**—**	**390.4**	**—**	**390.4**	**—**	**390.4**
Other comprehensive income	**—**	**—**	**—**	**—**	**5.8**	**5.8**	**—**	**5.8**
Non-cash equity transfer of net assets to UMERC	**—**	**—**	**(20.6)**	**—**	**—**	**(20.6)**	**—**	**(20.6)**
Other	**—**	**—**	**0.2**	**—**	**—**	**0.2**	**—**	**0.2**
Balance at December 31, 2017	**$ —**	**$ —**	**$ 2,664.9**	**$ 1,356.8**	**$ (17.5)**	**$ 4,004.2**	**$ —**	**$ 4,004.2**

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

INTEGRYS HOLDING, INC.

G. CONSOLIDATED STATEMENTS OF CAPITALIZATION

At December 31 *(in millions)*	Interest Rate	Year Due	2017	2016
Common shareholder's equity (see accompanying statement)			**$ 4,004.2**	$ 3,628.4
Long-term debt	**Interest Rate**	**Year Due**		
WPS Senior Notes (unsecured)	5.65%	2017	**—**	125.0
	1.65%	2018	**250.0**	250.0
	6.08%	2028	**50.0**	50.0
	5.55%	2036	**125.0**	125.0
	3.671%	2042	**300.0**	300.0
	4.752%	2044	**450.0**	450.0
PGL First and Refunding Mortgage Bonds (secured) [1]	8.00%	2018	**5.0**	5.0
	4.63%	2019	**75.0**	75.0
	3.90%	2030	**50.0**	50.0
	1.875%	2033	**50.0**	50.0
	4.00%	2033	**50.0**	50.0
	3.98%	2042	**100.0**	100.0
	3.96%	2043	**220.0**	220.0
	4.21%	2044	**200.0**	200.0
	3.65%	2046	**50.0**	50.0
	3.65%	2046	**150.0**	150.0
	3.77%	2047	**100.0**	—
NSG First Mortgage Bonds (secured) [2]	3.43%	2027	**28.0**	28.0
	3.96%	2043	**54.0**	54.0
MGU Senior Notes (unsecured)	3.11%	2027	**30.0**	—
	3.41%	2032	**30.0**	—
	4.01%	2047	**30.0**	—
MERC Senior Notes (unsecured)	3.11%	2027	**40.0**	—
	3.41%	2032	**40.0**	—
	4.01%	2047	**40.0**	—
Integrys Senior Notes (unsecured)	4.17%	2020	**250.0**	250.0
Integrys Junior Notes (unsecured)	3.60% [3]	2066	**114.9**	114.9
	6.00%	2073	**400.0**	400.0
Total			**3,281.9**	3,096.9
Unamortized debt issuance costs			**(31.7)**	(30.5)
Unamortized discount, net and other			**(0.6)**	(0.7)
Total long-term debt, including current portion			**3,249.6**	3,065.7
Current portion of long-term debt			**(255.0)**	(125.0)
Total long-term debt			**2,994.6**	2,940.7
Total long-term capitalization			**$ 6,998.8**	$ 6,569.1

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

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

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

(3) Variable interest rate reset quarterly. At December 31, 2017 and 2016, the rate was 3.60% and 3.05%, respectively.

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

H. NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2017

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Nature of Operations—On June 29, 2015, Wisconsin Energy Corporation acquired our predecessor, Integrys Energy Group, Inc., which became a wholly owned subsidiary of Wisconsin Energy Corporation. Wisconsin Energy Corporation then changed its name to WEC Energy Group, Inc. In this report, when we refer to the "WEC Merger," we are referring to this acquisition. See Note 4, Related Parties, for more information.

In December 2016, both the MPSC and the PSCW approved the operation of UMERC as a stand-alone utility owned by WEC Energy Group in the Upper Peninsula of Michigan, and it became operational effective January 1, 2017. This utility holds the electric and natural gas distribution assets previously held by WPS and WE located in the Upper Peninsula of Michigan. UMERC currently meets its market obligations through power purchase agreements with WPS and WE. UMERC will begin to generate electricity when its new generation solution in the Upper Peninsula of Michigan begins commercial operation, which is expected to occur in 2019.

As used in these notes, the term "financial statements" refers to the consolidated financial statements. This includes the income statements, statements of comprehensive income, balance sheets, statements of cash flows, statements of equity, and statements of capitalization, unless otherwise noted. In this report, when we refer to "us," "we," "our," or "ours," we are referring to Integrys Holding, Inc. (Integrys).

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

- Wisconsin segment – Consists of WPS, which is engaged primarily in the generation of electricity and the distribution of electricity and natural gas in Wisconsin. WPS's electric and natural gas operations in the state of Michigan were also included in this segment prior to their transfer to UMERC effective January 1, 2017.

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

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

- Electric transmission segment – Through December 31, 2017, consisted of our approximate 34% ownership interest in ATC, a federally regulated electric transmission company. In January 2018, we transferred our ownership in WPSI, which held our ownership interest in ATC, to another subsidiary of WEC Energy Group.

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

Our financial statements also reflect our proportionate interests in certain jointly owned utility facilities. See Note 7, Jointly Owned Utility Facilities, for more information. The cost method of accounting is used for investments when we do not have significant influence over the operating and financial policies of the investee. Investments in companies not controlled by us, but over which we have significant influence regarding the operating and financial policies of the investee, are accounted for using the equity method. See Note 19, Investment in American Transmission Company, for more information.

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

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

(d) Revenues and Customer Receivables—We recognize revenues related to the sale of energy on the accrual basis and include estimated amounts for services provided but not yet billed to customers.

We present revenues net of pass-through taxes on the income statements.

Below is a summary of the significant mechanisms our utility subsidiaries had in place that allowed them to recover or refund changes in prudently incurred costs from rate case-approved amounts:

- Fuel and purchased power costs were recovered from customers on a one-for-one basis by our Wisconsin wholesale electric operations and our Michigan retail electric operations.

- Our retail electric rates in Wisconsin are established by the PSCW and include base amounts for fuel and purchased power costs. The electric fuel rules set by the PSCW allow us to defer, for subsequent rate recovery or refund, under- or over-collections of actual fuel and purchased power costs that exceed a 2% price variance from the costs included in the rates charged to customers. WPS monitors the deferral of under-collected costs to ensure that it does not cause it to earn a greater ROE than authorized by the PSCW.

- The rates for all of our natural gas utilities included one-for-one recovery mechanisms for natural gas commodity costs. We defer any difference between actual natural gas costs incurred and costs recovered through rates as a current asset or liability. The deferred balance is returned to or recovered from customers at intervals throughout the year.

- The rates of PGL and NSG included riders for cost recovery of both environmental cleanup costs and energy conservation and management program costs.

- MERC's rates included a conservation improvement program rider for cost recovery of energy conservation and management program costs as well as a financial incentive for meeting energy savings goals.

- The rates of PGL and NSG included riders for cost recovery or refund of uncollectible expense based on the difference between actual uncollectible write-offs and the amounts recovered in rates.

- The rates of PGL, NSG, MERC, and MGU included decoupling mechanisms. These mechanisms differ by state and allow utilities to recover or refund differences between actual and authorized margins. MGU's decoupling mechanism was discontinued after December 31, 2015. See Note 23, Regulatory Environment, for more information.

- PGL's rates included a cost recovery mechanism for projects under its QIP rider, including SMP.

Revenues are also impacted by other accounting policies related to WPS's participation in the MISO Energy Markets. WPS sells and purchases power in the MISO Energy Markets, which operate under both day-ahead and real-time markets. WPS records energy transactions in the MISO Energy Markets on a net basis for each hour. If WPS was a net seller in a particular hour, the net amount was reported as operating revenues. If WPS was a net purchaser in a particular hour, the net amount was recorded as cost of sales on our income statements.

WPS provides regulated electric and natural gas service to customers in northeastern and central Wisconsin and provided this service to customers in the Upper Peninsula of Michigan through December 31, 2016. See Note 4, Related Parties, for information regarding the transfer of WPS's customers located in the Upper Peninsula of Michigan to UMERC as of January 1, 2017. We also provide regulated natural gas service to customers in Illinois, Minnesota, and Michigan. The geographic concentration of our customers did not contribute significantly to our overall exposure to credit risk. We periodically review customers' credit ratings, financial statements, and historical payment performance and require them to provide collateral or other security as needed. Credit risk exposure at PGL and NSG is mitigated by their recovery mechanisms for uncollectible expense discussed above. As a result, we did not have any significant concentrations of credit risk at December 31, 2017. In addition, there were no customers that accounted for more than 10% of our revenues for the year ended December 31, 2017.

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

(in millions)	2017	2016
Natural gas in storage	**$ 128.4**	$ 149.1
Materials and supplies	**65.8**	54.3
Fossil fuel	**43.8**	66.7
Total	**$ 238.0**	$ 270.1

PGL and NSG price natural gas storage injections at the calendar year average of the costs of natural gas supply purchased. Withdrawals from storage are priced on the LIFO cost method. Inventories stated on a LIFO basis represented approximately 34% and 38% of total inventories at December 31, 2017 and 2016, respectively. The estimated replacement cost of natural gas in inventory at December 31, 2017 and 2016, exceeded the LIFO cost by $152.1 million and $92.9 million, respectively. In calculating these replacement amounts, PGL and NSG used a Chicago city-gate natural gas price per Dth of $4.68 at December 31, 2017, and $3.63 at December 31, 2016.

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

(f) Investments Held in Rabbi Trust—We have investments that are held in a rabbi trust that is used to fund participants' benefits under our deferred compensation plan and certain non-qualified pension plans. All assets held within the rabbi trust are restricted as they can only be withdrawn from the trust to make qualifying benefit payments. The trust holds investments that are classified as trading securities for accounting purposes. As we do not intend to sell the investments in the near term, they are included in other long-term assets on our balance sheets. The net unrealized gains (losses) included in earnings related to the investments held at the end of the period were $18.8 million, $4.0 million, and $(0.4) million for the years ended December 31, 2017, 2016, and 2015, respectively.

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

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

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

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

Annual Utility Composite Depreciation Rates	2017	2016	2015
WPS	**2.55%**	2.58%	2.60%
PGL	**3.29%**	3.31%	3.35%
NSG	**2.43%**	2.44%	2.45%
MERC	**2.51%**	2.53%	2.50%
MGU	**2.61%**	2.63%	2.65%

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

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

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

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

The majority of AFUDC is recorded at WPS. Approximately 50% of WPS's retail jurisdictional CWIP expenditures are subject to the AFUDC calculation. For 2017, WPS's average AFUDC retail rate was 7.72%, and its average AFUDC wholesale rate was 1.01%. The other utilities did not record significant AFUDC for 2017, 2016, or 2015.

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

(in millions)	**2017**	2016	2015
AFUDC – Debt	**$ 1.6**	$ 8.1	$ 7.1
AFUDC – Equity	**4.1**	19.5	17.7

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

(k) Asset Impairment—Goodwill and other intangible assets with indefinite lives are subject to an annual impairment test. Interim impairment tests are performed when impairment indicators are present. Our reporting units containing goodwill perform annual goodwill impairment tests as of July 1 of each year. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit exceeds the reporting unit's fair value. An impairment loss is recorded for the excess of the carrying amount of the goodwill over its implied fair value. See Note 9, Goodwill and Other Intangible Assets, for more information. Intangible assets with definite lives are reviewed for impairment on a quarterly basis.

We periodically assess the recoverability of certain long-lived assets when factors indicate the carrying value of such assets may be impaired or such assets are planned to be sold. These assessments require significant assumptions and judgments by management. The long-lived assets assessed for impairment generally include certain assets within regulated operations that may not be fully recovered from our customers as a result of regulatory decisions that will be made in the future, and assets within nonregulated operations that are proposed to be sold or are currently generating operating losses.

An impairment loss is recognized when the carrying amount of an asset is not recoverable and exceeds the fair value of the asset. The carrying amount of an asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. An impairment loss is measured as the excess of the carrying amount of the asset in comparison to the fair value of the asset.

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

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

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

(m) Stock-Based Compensation—Prior to the WEC Merger, our employees were granted awards under our stock-based compensation plans. Pursuant to the Merger Agreement, immediately prior to completion of the merger, all of our outstanding stock-based compensation awards became fully vested and were either paid to award recipients in cash, or the value of the awards was deferred into a deferred compensation plan. The additional expense recorded in 2015 associated with the accelerated vesting of these awards totaled $22.7 million and is included in merger costs on the income statement. The total intrinsic value of awards that were settled in 2015 due to the WEC Merger was $61.7 million. The actual tax benefit realized for the tax deductions from the settled awards was $22.7 million. See Note 4, Related Parties, for more information regarding the WEC Merger.

In 2016, our employees began participating in the WEC Energy Group stock-based compensation plans. In accordance with the WEC Energy Group shareholder approved WEC Energy Group 1993 Omnibus Stock Incentive Plan, Amended and Restated Effective as of January 1, 2016, WEC Energy Group provides long-term incentives through its equity interests to its non-employee directors, officers, and other key employees. The plan provides for the granting of stock options, restricted stock, performance shares, and other stock-based awards. Awards may be paid in WEC Energy Group common stock, cash, or a combination thereof. The number of shares of WEC Energy Group common stock authorized for issuance under the plan is 34.3 million.

Stock-based compensation expense is allocated to us based on the outstanding awards held by our employees and our allocation of labor costs. Awards classified as equity awards are measured based on their grant-date fair value. Awards classified as liability awards are recorded at fair value each reporting period.

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. As we did not have any excess tax benefits that had not been recognized in prior years, we were not required to record a cumulative-effect adjustment to retained earnings as a result of the adoption of this ASU.

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.

As we were not required to record a cumulative-effect adjustment to retained earnings, and we did not record any excess tax benefits in 2017, adoption of ASU 2016-09 had no impact on our financial statements.

Stock Options

Our employees are granted WEC Energy Group non-qualified stock options that generally vest on a cliff-basis after a three-year period. The exercise price of a stock option under the plan cannot be less than 100% of the fair market value of WEC Energy Group common stock on the grant date. Historically, all stock options have been granted with an exercise price equal to the fair market value of WEC Energy Group common stock on the date of the grant. Options may not be exercised within 6 months of the grant date except in the event of a change in control. Options expire no later than 10 years from the date of grant.

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

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

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

Restricted Shares

WEC Energy Group restricted shares granted to our employees have a three-year vesting period with one-third of the award vesting on each anniversary of the grant date. The restricted shares are classified as equity awards.

Performance Units

Officers and other key employees are granted performance units under the WEC Energy Group Performance Unit Plan. Under the plan, the ultimate number of units that will be awarded is dependent on WEC Energy Group's total shareholder return (stock price appreciation plus dividends) as compared to the total shareholder return of a peer group of companies over a three-year period, and beginning in 2017, other performance metrics as determined by the Compensation Committee. Participants may earn between 0% and 175% of the base performance unit award, as adjusted pursuant to the terms of the plan. Performance units granted on or after January 1, 2016 also accrue forfeitable dividend equivalents in the form of additional performance units.

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

See Note 10, Common Equity, for more information on WEC Energy Group's stock-based compensation plans.

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

Investment tax credits associated with regulated operations are deferred and amortized over the life of the assets. We and our subsidiaries are included in WEC Energy Group's consolidated federal and state income tax returns. In accordance with our tax allocation agreement with WEC Energy Group, we are allocated income tax payments and refunds based on our separate tax computation. See Note 14, Income Taxes, for more information.

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

(o) Fair Value Measurements—Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price).

Fair value accounting rules provide a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are defined as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are observable, either directly or indirectly, but are not quoted prices included within Level 1. Level 2 includes those financial instruments that are valued using external inputs within models or other valuation methods.

Level 3 – Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methods that result in management's best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to customers' needs.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. We use a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical measure for valuing certain derivative assets and liabilities. We primarily use a market approach for recurring fair value measurements and attempt to use valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

When possible, we base the valuations of our derivative assets and liabilities on quoted prices for identical assets and liabilities in active markets. These valuations are classified in Level 1. The valuations of certain contracts not classified as Level 1 may be based on quoted market prices received from counterparties and/or observable inputs for similar instruments. Transactions valued using these inputs are classified in Level 2. Certain derivatives are categorized in Level 3 due to the significance of unobservable or internally-developed inputs.

Derivatives were transferred between levels of the fair value hierarchy primarily due to observable pricing becoming available. We recognize transfers between levels of the fair value hierarchy at their value as of the end of the reporting period.

Due to the short-term nature of cash and cash equivalents, net accounts receivable and unbilled revenues, short-term notes receivable, accounts payable, and short-term borrowings, the carrying amount of each such item approximates fair value. 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 value of long-term debt is categorized within Level 2 of the fair value hierarchy.

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

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

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

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

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

(q) Guarantees—We follow the guidance of the Guarantees Topic of the FASB Accounting Standards Codification, which requires that the guarantor recognize, at the inception of the guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. See Note 17, Guarantees, for more information.

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

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

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

(t) Environmental Remediation Costs—We are subject to federal and state environmental laws and regulations that in the future may require us to pay for environmental remediation at sites where we have been, or may be, identified as a potentially responsible party. Loss contingencies may exist for the remediation of hazardous substances at various potential sites, including coal combustion product landfill sites and manufactured gas plant sites. See Note 8, Asset Retirement Obligations, for more information regarding coal combustion product landfill sites and Note 21, Commitments and Contingencies, for more information regarding manufactured gas plant sites.

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

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

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

(u) Subsequent Events—Subsequent events were evaluated for potential recognition or disclosure through March 23, 2018, which is the date the financial statements were available to be issued.

NOTE 2—ACQUISITIONS

Acquisition of a Wind Energy Generation Facility in Wisconsin

In October 2017, WPS, along with two other unaffiliated utilities, entered into an agreement to purchase the Forward Wind Energy Center, which consists of 86 wind turbines located in Wisconsin with a total capacity of 129 MW. 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 FERC approved the transaction on January 16, 2018 and the PSCW approved the transaction on March 20, 2018. The transaction is expected to close in the spring of 2018.

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

On June 30, 2017, WEC Energy Group completed the acquisition of Bluewater for $226.0 million. Bluewater owns natural gas storage facilities in Michigan that will provide a portion of the current natural gas storage needs for WPS's natural gas utility operations. In September 2017, WPS entered into a long-term service agreement with a wholly owned subsidiary of Bluewater to take the allocated storage, which was then approved by the PSCW in November 2017. See Note 23, Regulatory Environment, for more information.

NOTE 3—DISPOSITIONS

Dispositions

Corporate and Other Segment – Sale of Integrys Transportation Fuels

In November 2015, we sold our 30% joint interest in AMP Trillium LLC. This transaction was not significant, and there was no gain or loss recorded on the sale. In addition, in the fourth quarter of 2015, we lowered the fair value of the remaining ITF assets to fair market value, less costs to sell. This pre-tax fair value adjustment of $26.5 million ($16.0 million after-tax) was recorded in impairment losses on the income statements.

In February 2016, we sold ITF, a provider of CNG fueling services and a single-source provider of CNG fueling facility design, construction, operation, and maintenance. There was no gain or loss recorded on the sale, as ITF's assets and liabilities were adjusted to fair value, less costs to sell in 2015. The results of operations of ITF remained in continuing operations through the sale date as the sale of ITF did not represent a shift in our corporate strategy and did not have a major effect on our operations and financial results. We recognized income before income taxes from ITF of $5.8 million for the year ended December 31, 2016 and a loss before income taxes from ITF of $20.9 million for the year ended December 31, 2015.

Corporate and Other Segment – Sale of Certain PDL Solar Power Generation Plants

In June 2015, we sold 48 solar power generation plants owned by PDL, including our ownership interest in INDU Solar Holdings, LLC, to TerraForm Power, Inc. (TerraForm) for $47.8 million. These solar plants were located throughout Arizona, California, Connecticut, Massachusetts, New Jersey, and Pennsylvania. In 2015, we recorded a pre-tax gain on the sale of $5.2 million, which included transaction costs of $0.9 million. The pre-tax gain was reported as a component of other operation and maintenance on the income statements. The results of operations of these solar 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. In connection with the sale, we entered into an asset management agreement with TerraForm related to the majority of the remaining solar assets owned by PDL. Under this agreement, TerraForm is contracted to perform the day-to-day management of these remaining solar assets. We recognized income before income taxes from these solar assets of approximately $1 million for the year ended December 31, 2015.

Corporate and Other Segment – Sale of WPS Westwood Generation, LLC (Westwood)

In November 2012, Sunbury Holdings, LLC, which was a subsidiary of IES, sold all of the membership interests of Westwood, a waste coal generation plant located in Pennsylvania. In addition to cash proceeds received, IES received a $4.0 million note receivable from the buyer with a seven and one-half year term. In 2015, we evaluated the collectability of the note receivable and recorded an impairment loss of $3.8 million, which was reported in impairment losses on the income statements.

Corporate and Other Segment – Sale of IES Retail Energy Business

In November 2014, we sold IES's retail energy business to Exelon Generation Company, LLC. The sale of the retail energy business was the result of a previously announced shift in our corporate strategy to focus on the regulated businesses and had a major effect on our operations and financial results. Therefore, its results of operations were classified as discontinued operations beginning in the fourth quarter of 2014.

The following table shows the components of discontinued operations related to the sale of the IES retail energy business recorded on the income statement:

(in millions)		2015
Other operation and maintenance	$	(1.2)
Property and revenue taxes		(0.2)
Other income, net		0.1
Loss before taxes		(1.3)
Income tax benefit		(0.5)
Discontinued operations, net of tax	$	(0.8)

NOTE 4—RELATED PARTIES

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

We provide and receive services, property, and other items of value to and from our parent, WEC Energy Group, and other subsidiaries of WEC Energy Group. Following the WEC Merger on June 29, 2015, Integrys Business Support, LLC (IBS) changed its name to WBS, and a new AIA (Non-WBS AIA) went into effect. The new Non-WBS AIA included the former Wisconsin Energy Corporation subsidiaries. It governed the provision and receipt of services by WEC Energy Group's subsidiaries, except that WBS continued to provide services to us and our subsidiaries only under the existing WBS AIAs. WBS provided services to WEC Energy Group and the former Wisconsin Energy Corporation subsidiaries under interim WBS AIAs. The Non-WBS AIA included no other significant changes from the prior Non-IBS AIA. The PSCW and all other relevant state commissions approved the Non-WBS AIA or granted appropriate waivers related to the Non-WBS AIA.

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

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

A new AIA took effect January 1, 2017. The new agreement replaced the previous agreements. The pricing methodology and services under this new agreement are substantially identical to those under the agreements that were replaced. All of the applicable state commissions approved modifications to the new AIA to incorporate WEC Energy Group's acquisition of Bluewater. See Note 2, Acquisitions, for more information about the Bluewater acquisition.

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

In January 2018, we transferred our ownership in WPSI, which held our ownership interest in ATC, to another subsidiary of WEC Energy Group.

We provide services to and receive services from ATC for its transmission facilities under several agreements approved by the PSCW. Services are billed to ATC under these agreements at our fully allocated cost. See Note 19, Investment in American Transmission Company, for more information.

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

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

(in millions)	2017	2016	2015
Transactions with WE [(1)]			
Natural gas sales to WE from WPS	**$ 1.6**	$ 1.9	$ 0.4
Billings to WE from WPS	**4.5**	4.2	4.9
Billings from WE to WPS	**28.2**	9.0	13.4
Transactions with WBS [(1)]			
Billings to WBS [(2)]	**103.5**	24.8	—
Billings from WBS [(3)]	**457.7**	377.0	—
Transactions with UMERC [(4)]			
Electric sales to UMERC from WPS	**16.2**	—	—
Transactions with Bluewater [(5)]			
Storage service fees	**0.3**	—	—
Transactions with equity-method investees			
Rental payments to WRPC [(6)]	**1.3**	—	—
Purchases of energy from WRPC	**0.5**	3.7	3.8
Charges from WRPC for services	**2.2**	—	—
Charges to WRPC for operations	**0.9**	0.7	1.1

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

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

(3) Includes $36.7 million of cash paid related to pension trust assets transferred to us in conjunction with the Integrys pension plan split for the year ended December 31, 2017. Effective January 1, 2017, the Integrys Energy Group Retirement Plan was split into six separate plans. While the split did not impact our pension benefit obligation, federal regulations required a different allocation of assets among the new plans. Assets were transferred out of our plan in January 2017. See Note 18, Employee Benefits, for more information. Includes $46.1 million for the transfer of certain software assets to us for the year ended December 31, 2017. Includes $31.2 million for the transfer of certain benefit-related liabilities to WBS and $95.0 million for the transfer of certain software assets to us for the year ended December 31, 2016.

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

(5) The acquisition of Bluewater was completed June 30, 2017.

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

We manage our liquidity in part by maintaining adequate financing commitments with related parties. We have the ability to borrow to and from our parent, WEC Energy Group, in amounts up to $400 million. At December 31, 2017 we had a short-term note receivable from WEC Energy Group of $278.2 million. At December 31, 2016, we had a short-term note payable to WEC Energy Group of $42.0 million. See Note 12, Short-Term Debt and Lines of Credit, for more information.

Upper Michigan Energy Resources Corporation

In December 2016, both the MPSC and the PSCW approved the operation of UMERC as a stand-alone utility in the Upper Peninsula of Michigan. UMERC, a subsidiary of WEC Energy Group, became operational effective January 1, 2017, and WPS transferred customers and property, plant, and equipment as of that date. WPS transferred approximately 9,000 retail electric customers and 5,300 natural gas customers to UMERC, along with approximately 600 miles of electric distribution lines and approximately 100 miles of natural gas distribution mains. WPS also transferred related electric distribution substations in the Upper Peninsula of Michigan and all property rights for the distribution assets to UMERC. The book value of the net assets (including the related deferred income tax liabilities) transferred to UMERC from WPS as of January 1, 2017, was $20.6 million. This transaction was a non-cash equity transfer recorded to additional paid in capital between entities under common control, and therefore, did not result in the recognition of a gain or loss. UMERC currently meets its market obligations through power purchase agreements with WPS and WE.

WEC Merger

On June 29, 2015, the WEC Merger was completed and we became a wholly owned subsidiary of Wisconsin Energy Corporation. Wisconsin Energy Corporation then changed its name to WEC Energy Group, Inc. Our shareholders received 1.128 shares of Wisconsin Energy Corporation common stock and $18.58 in cash for each share of our common stock. In addition, all of our unvested stock-based compensation awards became fully vested upon the close of the transaction. All outstanding awards were either paid out in cash to award recipients or the value of the awards was deferred into a deferred compensation plan. The total purchase price was approximately $5.6 billion.

The WEC Merger was subject to the approvals of various government agencies, including the FERC, Federal Communications Commission, PSCW, ICC, MPSC, and MPUC. Approvals were obtained from all agencies subject to several conditions.

The PSCW order requires that any future electric generation projects affecting Wisconsin ratepayers submitted by WEC Energy Group or its subsidiaries will first consider the extent to which existing intercompany resources can meet energy and capacity needs. In September 2015, WPS and WE filed a joint integrated resource plan with the PSCW for their combined loads, which indicated that there was no need to proceed with the proposed construction of a new generating unit at the Fox Energy Center site. WPS has been authorized to recover the costs it recorded related to the proposed construction.

The ICC order included a base rate freeze for PGL and NSG effective for two years after the close of the WEC Merger. This base rate freeze expired in 2017 and did not impact PGL's or NSG's ability to adjust rates through various riders or gas cost recovery mechanisms.

In connection with the WEC Merger, we recorded pre-tax merger costs of $86.9 million during 2015. Merger costs recorded after 2015 were not significant. Merger costs consisted of employee-related expenses, professional fees, and other miscellaneous costs. Included in the 2015 merger costs was $43.2 million of expense related to the accelerated vesting of our outstanding stock-based compensation awards and change-in-control payments.

The 2015 merger costs also included $18.4 million of severance expense that resulted from employee reductions related to the post-merger integration. Severance expense incurred after 2015 was not significant. The 2015 severance expense was recorded in the following segments:

(in millions)	Year ended December 31, 2015
Wisconsin	**$ 4.6**
Illinois	**0.9**
Other states	**0.1**
Corporate and other	**12.8**
Total severance expense	**$ 18.4**

Severance payments of $15.7 million were made during 2015. Severance payments made in 2017 and 2016 were not significant. The severance accrual on our balance sheets at December 31, 2017 and 2016 was not significant.

NOTE 5—REGULATORY ASSETS AND LIABILITIES

We recorded a $1,069 million change in our deferred taxes for our regulated utilities due to the enactment of the Tax Legislation, which resulted in an increase to the 2017 Tax Legislation impact and income tax related regulatory liabilities as well as a decrease to certain existing income tax related items in regulatory assets, both in the tables below. The $1,069 million change in our deferred taxes represents our estimate of the tax benefit that will be returned to ratepayers through future refunds, bill credits, riders, or reductions in other regulatory assets. See Note 14, Income Taxes, for more information on the Tax Legislation.

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

(in millions)	2017	2016	See Note
Regulatory assets [1] [2]			
Environmental remediation costs [3]	**$ 598.9**	$ 633.2	21
Unrecognized pension and OPEB costs [4]	**476.2**	532.4	18
AROs	**150.7**	139.5	8
Uncollectible expense [5]	**35.1**	25.6	1(d)
Termination of a tolling agreement with Fox Energy Company LLC [6]	**27.2**	33.7	
Crane Creek production tax credits [7]	**22.8**	29.6	
Energy costs recoverable through rate adjustments [8]	**20.3**	22.9	
Unamortized loss on reacquired debt [9]	**14.6**	15.5	
Derivatives	**14.1**	16.9	1(p)
De Pere Energy Center [10]	**14.0**	16.7	
Income tax related items	**12.0**	75.0	14
Other	**37.0**	44.4	
Total regulatory assets	**$ 1,422.9**	$ 1,585.4	
Balance Sheet Presentation			
Current assets [11]	**$ 37.2**	$ 50.3	
Regulatory assets	**1,385.7**	1,535.1	
Total regulatory assets	**$ 1,422.9**	$ 1,585.4	

(1) Based on prior and current rate treatment, we believe it is probable that our utilities will continue to recover from customers the regulatory assets in the table.

(2) As of December 31, 2017, we had $98.9 million of regulatory assets not earning a return and $7.1 million of regulatory assets earning a return based on short-term interest rates. The regulatory assets not earning a return primarily relate to certain environmental remediation costs, the recovery of which depends on the timing of the actual expenditures, as well as certain unrecognized pension and OPEB costs, unamortized loss on reacquired debt, and plant-related costs. The other regulatory assets in the table either earn a return or the cash has not yet been expended, in which case the regulatory assets are offset by liabilities.

(3) As of December 31, 2017, we had not yet made cash expenditures for $557.7 million of these environmental remediation costs.

(4) Represents the unrecognized future pension and OPEB costs resulting from actuarial gains and losses on defined benefit and OPEB plans. We are authorized recovery of this regulatory asset over the average remaining service life of each plan.

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

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

(7) In 2012, WPS elected to claim and subsequently received a Section 1603 Grant for the Crane Creek wind project in lieu of the production tax credit. As a result, WPS reversed previously recorded production tax credits. WPS also reduced the depreciable basis of the qualifying facility by the amount of the grant proceeds, which will result in a reduction of depreciation and amortization expense over a 12-year period. WPS recorded a regulatory asset for the deferral of previously recorded production tax credits and is authorized recovery of this net regulatory asset through 2039.

(8) Represents energy costs that will be recovered from customers in the future.

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

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

(11) Short-term regulatory assets are included in accounts receivable and unbilled revenues on our balance sheets.

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

(in millions)	2017	2016	See Note
Regulatory liabilities			
2017 Tax Legislation impact and income tax related	**$ 972.8**	$ 5.3	14
Removal costs [1]	**376.1**	372.1	
Unrecognized pension and OPEB costs [2]	**95.7**	58.6	18
Energy costs refundable through rate adjustments [3]	**11.5**	20.1	
Derivatives	**6.4**	25.9	1(p)
Uncollectible expense [4]	**—**	13.8	1(d)
Other	**28.5**	22.9	
Total regulatory liabilities	**$ 1,491.0**	$ 518.7	
Balance sheet presentation			
Other current liabilities	**$ 11.8**	$ 11.0	
Regulatory liabilities	**1,479.2**	507.7	
Total regulatory liabilities	**$ 1,491.0**	$ 518.7	

(1) Represents amounts collected from customers to cover the cost of future removal of property, plant, and equipment.

(2) Represents the unrecognized future pension and OPEB costs resulting from actuarial gains and losses on defined benefit and OPEB plans. We will amortize this regulatory liability into net periodic benefit cost over the average remaining service life of each plan.

(3) Represents energy costs that will be refunded to customers in the future.

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

NOTE 6—PROPERTY, PLANT, AND EQUIPMENT

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

(in millions)	2017	2016
Electric utility property, plant, and equipment	**$ 4,204.5**	$ 4,277.7
Natural gas utility property, plant, and equipment	**7,117.1**	6,549.6
Total utility property, plant, and equipment	**11,321.6**	10,827.3
Less: Accumulated depreciation	**3,270.1**	3,300.5
Net	**8,051.5**	7,526.8
CWIP	**280.8**	180.9
Plant to be retired, net	**57.9**	—
Net utility property, plant, and equipment	**8,390.2**	7,707.7
Non-utility and other property, plant, and equipment	**88.7**	87.1
Less: Accumulated depreciation	**18.6**	15.0
Net	**70.1**	72.1
CWIP	**0.1**	0.1
Net non-utility and other property, plant, and equipment	**70.2**	72.2
Total property, plant, and equipment	**$ 8,460.4**	$ 7,779.9

We evaluate property, plant, and equipment for impairment whenever indicators of impairment exist. In 2015, impairments of $12.1 million were recorded to net non-utility plant and other property, plant, and equipment. These impairment losses are included in impairment losses on our income statements.

Effective January 1, 2017, WPS transferred approximately 600 miles of electric distribution lines and approximately 100 miles of natural gas distribution mains to UMERC. WPS also transferred related electric distribution substations in the Upper Peninsula of

Michigan. The net book value of the property, plant, and equipment we transferred to UMERC was $22.3 million. See Note 4, Related Parties, for more information.

Wisconsin Segment Plant to be Retired

We have evaluated future plans for our older and less efficient fossil fuel generating units and have announced our plans for the retirement of the plants identified below. The net book value of these plants was classified as plant to be retired within property, plant, and equipment on our balance sheet at December 31, 2017. In addition, severance expense in the amount of $3.6 million was recorded within the Wisconsin segment in 2017 related to these announced plant retirements.

Pulliam Power Plant

As a result of MISO's ruling that WPS will be able retire the Pulliam generating units when certain transmission lines are completed, expected near the end of 2018, retirement of the Pulliam generating units was probable at December 31, 2017. The net book value of these generating units was $44.9 million at December 31, 2017. This amount was classified as plant to be retired within property, plant, and equipment on our balance sheet. These units are included in rate base, and WPS continues to depreciate them on a straight-line basis using the composite depreciation rates approved by the PSCW. See Note 21, Commitments and Contingencies, for more information.

Edgewater Unit 4

As a result of the continued implementation of the Consent Decree related to the jointly owned Columbia and Edgewater plants, retirement of the Edgewater 4 generating unit was probable at December 31, 2017. We anticipate that the plant will be retired by September 30, 2018. The net book value of our ownership share of this generating unit was $13.0 million at December 31, 2017. This amount was classified as plant to be retired within property, plant, and equipment on our balance sheet. This unit is 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 21, Commitments and Contingencies, for more information regarding the Consent Decree.

NOTE 7—JOINTLY OWNED UTILITY FACILITIES

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

Information related to jointly owned facilities at December 31, 2017 was as follows:

(in millions, except for percentages and MW)	Weston Unit 4	Columbia Energy Center Units 1 and 2	Edgewater Unit 4 [3]
Ownership	70.0%	29.5% [2]	31.8%
WPS's share of rated capacity (MW) [1]	383.9	319.7	98.0
In-service date	2008	1975 and 1978	1969
Property, plant, and equipment	$ 600.5	$ 412.7	$ 45.9
Accumulated depreciation	$ (189.2)	$ (127.3)	$ (32.9)
CWIP	$ 5.3	$ 27.6	$ —

(1) Based on expected capacity ratings for summer 2018. The summer period is the most relevant for capacity planning purposes. This is a result of continually reaching demand peaks in the summer months, primarily due to air conditioning demand.

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

(3) We anticipate that the Edgewater 4 generating unit will be retired by September 30, 2018. See Note 6, Property, Plant, and Equipment, for more information.

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

NOTE 8—ASSET RETIREMENT OBLIGATIONS

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

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

(in millions)	**2017**	2016	2015
Balance as of January 1	**$ 492.7**	$ 509.2	$ 479.1
Accretion	**24.1**	25.1	23.9
Additions and revisions to estimated cash flows	**21.0** (1)	—	19.6 (2)
Liabilities settled	**(36.1)**	(41.6)	(13.4)
Balance as of December 31	**$ 501.7**	$ 492.7	$ 509.2

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

(2) During 2015, an ARO of $9.0 million was recorded for the Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities rule passed by the EPA in April 2015. In addition, our AROs increased $8.2 million in 2015 due to revisions made to estimated cash flows for changes in the weighted average cost to retire natural gas distribution pipe at PGL and NSG. We also revised the AROs recorded for WPS's fly-ash landfills during 2015 due to changes in estimated removal costs and settlement dates.

NOTE 9—GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill represents the excess of the cost of an acquisition over the fair value of the identifiable net assets acquired. The following table shows our goodwill balances by segment as of December 31, 2017 and 2016. Our goodwill balances did not change during the years ended December 31, 2017 and 2016.

	Wisconsin		**Illinois**		**Other States**		**Total**	
(in millions)	**2017**	2016	**2017**	2016	**2017**	2016	**2017**	2016
Gross goodwill	**$ 36.4**	$ 36.4	**$ 630.1**	$ 630.1	**$ 267.0**	$ 267.0	**$ 933.5**	$ 933.5
Accumulated impairment losses	**—**	—	**(192.8)**	(192.8)	**(104.9)**	(104.9)	**(297.7)**	(297.7)
Net goodwill	**$ 36.4**	$ 36.4	**$ 437.3**	$ 437.3	**$ 162.1**	$ 162.1	**$ 635.8**	$ 635.8

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

We reclassified ITF's goodwill to assets held for sale during the third quarter of 2015. Due to the offers received for ITF, we recorded a non-cash goodwill impairment loss related to ITF of $15.8 million during the fourth quarter of 2015. See Note 3, Dispositions, for more information on the sale of ITF.

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

	December 31, 2017			December 31, 2016		
(in millions)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized intangible assets [1]	**$ 8.7**	**$ (6.0)**	**$ 2.7**	$ 16.0	$ (11.1)	$ 4.9
Unamortized intangible assets [2]	**5.7**	**—**	**5.7**	5.7	—	5.7
Total intangible assets	**$ 14.4**	**$ (6.0)**	**$ 8.4**	$ 21.7	$ (11.1)	$ 10.6

(1) Primarily represents contractual service agreements that provide for major maintenance and protection against unforeseen maintenance costs related to the combustion turbine generators at WPS's Fox Energy Center. The remaining weighted-average amortization period for our amortized intangible assets at December 31, 2017, was approximately two years.

(2) Consists primarily of a trade name.

During the second quarter of 2015, an impairment loss of $4.9 million was recorded related to the net carrying amount of PDL's amortized intangible assets. This loss is included in impairment losses on our income statements.

NOTE 10—COMMON EQUITY

Stock-Based Compensation

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

(in millions)	2017	2016	2015
WEC Energy Group stock options	**$ 2.0**	$ 1.4	$ —
WEC Energy Group restricted shares	**2.0**	3.4	—
WEC Energy Group performance units	**8.7**	4.0	—
Integrys performance stock rights	**—**	—	3.3
Integrys restricted share units	**—**	—	8.2
Integrys non-employee director deferred stock units	**—**	—	0.9
Stock-based compensation expense	**$ 12.7**	$ 8.8	$ 12.4
Related tax benefit	**$ 5.1**	$ 3.5	$ 5.0

Stock-based compensation costs capitalized during 2017, 2016, and 2015 were not significant.

Stock Options

The following is a summary of our employees' WEC Energy Group stock option activity during 2017:

Stock Options	Number of Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life *(in years)*	Aggregate Intrinsic Value *(in millions)*
Outstanding as of January 1, 2017	46,630	$ 55.36		
Granted	**46,450**	**$ 58.31**		
Transferred	**4,475**	**$ 57.08**		
Forfeited	**(4,090)**	**$ 57.55**		
Outstanding as of December 31, 2017	**93,465**	**$ 56.81**	**8.6**	**$ 0.9**
Exercisable as of December 31, 2017	**8,715**	**$ 56.13**	**8.4**	**$ 0.1**

The aggregate intrinsic value of outstanding and exercisable options in the above table represents the total pre-tax intrinsic value that would have been received by the option holders had they exercised all of their options on December 31, 2017. This is calculated as the difference between WEC Energy Group's closing stock price on December 31, 2017, and the option exercise price, multiplied by the number of in-the-money stock options.

As of December 31, 2017, we expected to recognize approximately $1.7 million of unrecognized compensation cost related to unvested and outstanding WEC Energy Group stock options over the next 1.7 years on a weighted-average basis.

During the first quarter of 2018, the Compensation Committee awarded 45,740 non-qualified WEC Energy Group stock options with an exercise price of $66.02 and a weighted-average grant date fair value of $7.77 per option to certain of our officers and other key employees under its normal schedule of awarding long-term incentive compensation.

Restricted Shares

The following is a summary of our employees' WEC Energy Group restricted stock activity during 2017:

Restricted Shares	Number of Shares	Weighted-Average Grant Date Fair Value
Outstanding as of January 1, 2017	21,423	$ 55.48
Granted	**4,605**	**$ 58.10**
Released	**(7,290)**	**$ 55.48**
Transferred	**1,459**	**$ 55.95**
Forfeited	**(2,167)**	**$ 56.12**
Outstanding as of December 31, 2017	**18,030**	**$ 56.11**

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

As of December 31, 2017, we expected to recognize approximately $2.4 million of unrecognized compensation cost related to WEC Energy Group restricted stock over the next 1.6 years on a weighted-average basis.

During the first quarter of 2018, the Compensation Committee awarded 4,206 WEC Energy Group restricted shares to our officers and other key employees under its normal schedule of awarding long-term incentive compensation. The grant date fair value of these awards was $64.99 per share.

Performance Units

During 2017 and 2016, the Compensation Committee awarded 19,990 and 19,710 WEC Energy Group performance units, respectively, to our officers and other key employees under the WEC Energy Group Performance Unit Plan.

At December 31, 2017, we had 34,517 performance units outstanding, including dividend equivalents. A liability of $1.5 million was recorded on our balance sheet at December 31, 2017 related to these outstanding units. As of December 31, 2017, we expected to recognize approximately $1.8 million of unrecognized compensation cost related to unvested and outstanding WEC Energy Group performance units over the next 1.4 years on a weighted-average basis.

In January 2018, the Compensation Committee awarded 18,260 WEC Energy Group performance units to our officers and other key employees under its normal schedule of awarding long-term incentive compensation.

Restrictions

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

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

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

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

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

As of December 31, 2017, restricted net assets of our consolidated subsidiaries totaled approximately $2.3 billion. Our equity in undistributed earnings of investees accounted for by the equity method was approximately $206 million. The total of these amounts exceeds 25% of our consolidated net assets as of December 31, 2017.

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

NOTE 11—PREFERRED STOCK

The following table shows our subsidiaries' authorized shares of preferred stock at December 31, 2017 and 2016. There were no shares outstanding.

	Shares Authorized
WPS	
$100 par value, Preferred Stock	**1,000,000**
PGL	
$100 par value, Cumulative Preferred Stock	**430,000**
NSG	
$100 par value, Cumulative Preferred Stock	**160,000**

NOTE 12—SHORT-TERM DEBT AND LINES OF CREDIT

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

(in millions, except percentages)	**2017**	**2016**
Commercial paper		
Amount outstanding at December 31	**$ 533.0**	$ 228.0
Average interest rate on amounts outstanding at December 31	**1.81%**	1.03%
Short-term notes payable to WEC Energy Group		
Amount outstanding at December 31	**$ —**	$ 42.0
Average interest rate on amount outstanding at December 31	**—%**	1.05%

Our average amount of commercial paper borrowings based on daily outstanding balances during 2017, was $246.0 million with a weighted-average interest rate during the period of 1.29%.

As of December 31, 2017, we had approximately $617.0 million of available capacity under our subsidiaries' bank back-up credit facilities and our intercompany short-term debt facility with WEC Energy Group. As of December 31, 2017, we had $533.0 million of commercial paper outstanding that was supported by the credit facilities.

WPS and PGL have entered into bank back-up credit facilities to maintain short-term credit liquidity which, among other terms, requires them to maintain, subject to certain exclusions, a minimum total funded debt to capitalization ratio of less than 65%. As of December 31, 2017, all companies were in compliance with their respective financial covenants.

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

(in millions)	Maturity		2017
Revolving credit facility (WPS) *	December 2020	$	400.0
Revolving credit facility (PGL)	October 2022		350.0
Revolving short-term notes payable to WEC Energy Group			400.0
Total short-term credit capacity		$	1,150.0
Less:			
Commercial paper outstanding		$	533.0
Short-term notes payable to WEC Energy Group			—
Available capacity under existing credit agreements		$	617.0

* In February 2018, WPS received approval from the PSCW to extend the maturity of its facility to October 2022.

The WPS and PGL facilities have renewal provisions for two one-year extensions, subject to lender approval.

The bank back-up credit facilities contain customary covenants, including certain limitations on the respective companies' ability to sell assets. The credit facilities also contain customary events of default, including payment defaults, material inaccuracy of representations and warranties, covenant defaults, bankruptcy proceedings, certain judgments, Employee Retirement Income Security Act of 1974 defaults, and change of control.

NOTE 13—LONG-TERM DEBT

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

Wisconsin Public Service Corporation

In November 2017, WPS's $125.0 million of 5.65% Senior Notes matured, and the outstanding principal was repaid with proceeds WPS received from selling commercial paper.

The Peoples Gas Light and Coke Company

In November 2017, PGL issued $100.0 million of 3.77% Series EEE Bonds due December 1, 2047. The net proceeds were used for general corporate purposes, including capital expenditures and the refinancing of short-term debt.

Minnesota Energy Resources Corporation

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 us. Remaining proceeds were used for general corporate purposes, including repayment of short-term debt borrowed from us.

Michigan Gas Utilities Corporation

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 us. Remaining proceeds were used for general corporate purposes, including repayment of short-term debt borrowed from us.

Bonds and Notes

The following table shows the future maturities of our long-term debt outstanding as of December 31, 2017:

(in millions)	Payments
2018	$ 255.0
2019	75.0
2020	250.0
2021	—
2022	—
Thereafter	2,701.9
Total	$ 3,281.9

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

In connection with our outstanding 2006 Junior Subordinated Notes Due 2066 (2006 Junior Notes), we executed a Replacement Capital Covenant dated December 1, 2006, as replaced by a new Replacement Capital Covenant on December 1, 2010 (Integrys RCC) for the benefit of persons that buy, hold, or sell a specified series of its long-term indebtedness (covered debt). Our 4.17% Senior Notes due November 1, 2020, have been designated as the covered debt under the Integrys RCC. The Integrys RCC provides that we may not redeem, defease, or purchase, and that our subsidiaries may not purchase, any 2006 Junior Notes on or before December 1, 2036, unless, subject to certain limitations described in the Integrys RCC, we have received a specified amount of proceeds from the sale of qualifying securities.

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

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

NOTE 14—INCOME TAXES

Income Tax Expense

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

(in millions)	2017	2016	2015
Current tax benefit	**$ (16.0)**	$ (60.3)	$ (27.9)
Deferred income taxes, net	**239.2**	260.8	161.4
Investment tax credit, net	**(1.7)**	(3.8)	(1.5)
Total income tax expense related to continuing operations	**221.5**	196.7	132.0
Total income tax benefit related to discontinued operations	**—**	—	(0.5)
Total	**$ 221.5**	$ 196.7	$ 131.5

Statutory Rate Reconciliation

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

	2017		2016		2015	
(in millions)	Amount	Effective Tax Rate	Amount	Effective Tax Rate	Amount	Effective Tax Rate
Expected tax at statutory federal tax	**$ 214.2**	**35.0 %**	$ 173.6	35.0 %	$ 106.1	35.0 %
State income taxes net of federal tax	**28.1**	**4.6 %**	23.2	4.7 %	18.1	6.0 %
Federal tax reform	**(19.3)**	**(3.2)%**	—	— %	—	— %
AFUDC – Equity	**(1.4)**	**(0.2)%**	(6.8)	(1.4)%	(6.1)	(2.0)%
Valuation allowance change	**(0.8)**	**(0.1)%**	(2.1)	(0.4)%	16.9	5.5 %
Other, net	**0.7**	**0.1 %**	8.8	1.7 %	(3.0)	(1.0)%
Total income tax expense	**$ 221.5**	**36.2 %**	$ 196.7	39.6 %	$ 132.0	43.5 %

The net impact of Tax Legislation in the amount of $21.2 million is represented in both the federal tax reform and state income taxes net of federal tax benefit lines above.

Deferred Income Tax Assets and Liabilities

On December 22, 2017, the Tax Legislation was signed into law. For businesses, the Tax Legislation reduces the corporate federal tax rate from a maximum of 35% to a 21% rate effective January 1, 2018. We estimated a preliminary tax benefit related to the re-measurement of our deferred taxes in the amount of approximately $1,090 million. Accordingly, the $1,069 million tax benefit related to our regulated operations was recorded as both an increase to regulatory liabilities as well as a decrease to certain existing regulatory assets as of December 31, 2017. The effects of Tax Legislation related to the non-utility operations of our other states segment and the operations at our corporate and other segment resulted in the recording of an income tax benefit of approximately $21.2 million for the year ended December 31, 2017. Our revaluation of our deferred tax assets and liabilities is subject to further clarification of the new law that cannot be estimated at this time. The impact of the Tax Legislation could materially differ from this estimate due to, among other things, changes in interpretations and assumptions we have made.

On December 22, 2017, the Securities and Exchange Commission staff issued guidance in Staff Accounting Bulletin 118 (SAB 118), Income Tax Accounting Implications of the Tax Cuts and Jobs Act, which provides for a measurement period of up to one year from the enactment date to complete accounting under GAAP for the tax effects of the legislation. Due to the complex and comprehensive nature of the enacted tax law changes, and their application under GAAP, certain amounts related to bonus depreciation and future tax benefit utilization recorded in the financial statements as a result of the Tax Legislation are to be considered "provisional" as discussed in SAB 118 and subject to revision. We are awaiting additional guidance from industry and income tax authorities in order to finalize our accounting.

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

(in millions)	2017	2016
Deferred tax assets		
Tax gross up – regulatory items	**$ 265.0**	$ —
Future tax benefits	**142.9**	171.8
Other	**47.7**	56.8
Total deferred tax assets	**455.6**	228.6
Valuation allowance	**(14.2)**	(15.0)
Net deferred tax assets	**$ 441.4**	$ 213.6
Deferred tax liabilities		
Property-related	**$ 1,468.5**	$ 1,978.0
Employee benefits and compensation	**53.0**	60.6
Regulatory deferrals	**49.4**	95.3
Other	**17.4**	27.7
Total deferred tax liabilities	**1,588.3**	2,161.6
Deferred tax liability, net	**$ 1,146.9**	$ 1,948.0

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

The components of net deferred tax assets associated with federal and state tax benefit carryforwards as of December 31, 2017 and 2016 are summarized in the tables below:

2017 ***(in millions)***		**Gross Value**		**Deferred Tax Effect**		**Valuation Allowance**	**Earliest Year of Expiration**
Future tax benefits as of December 31, 2017							
Federal foreign tax credit	**$**	**—**	**$**	**13.5**	**$**	**(13.5)**	**2018**
Other federal tax credit		**—**		**109.8**		**(0.1)**	**2025**
Charitable contribution		**12.9**		**3.7**		**(0.6)**	**2017**
State net operating loss		**183.0**		**11.0**		**—**	**2025**
State tax credit		**—**		**4.9**		**—**	**2017**
Balance as of December 31, 2017	**$**	**195.9**	**$**	**142.9**	**$**	**(14.2)**	

2016 ***(in millions)***		**Gross Value**		**Deferred Tax Effect**		**Valuation Allowance**	**Earliest Year of Expiration**
Future tax benefits as of December 31, 2016							
Federal net operating loss	$	74.2	$	26.0	$	—	2035
Federal foreign tax credit		—		13.5		(13.5)	2017
Other federal tax credit		—		112.4		—	2025
Charitable contribution		3.8		1.5		(1.5)	2016
State net operating loss		270.3		13.6		—	2025
State tax credit		—		4.8		—	2016
Balance as of December 31, 2016	$	348.3	$	171.8	$	(15.0)	

Valuation allowances of $14.2 million have been established for certain tax benefit carryforwards based on our projected ability to realize such benefits by off-setting future tax liabilities. This is primarily the result of the extension of bonus depreciation. Realization is dependent on generating sufficient tax liabilities prior to expiration of the tax benefit carryforwards.

Unrecognized Tax Benefits

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

(in millions)		**2017**		**2016**
Balance at January 1	**$**	**8.8**	$	3.4
Increase related to tax positions of prior years		**8.1**		6.5
Decrease related to tax positions of prior years		**—**		(0.1)
Increase related to tax positions of the current year		**0.4**		0.8
Decrease related to lapse of statutes		**—**		(1.8)
Balance at December 31	**$**	**17.3**	$	8.8

The amount of unrecognized tax benefits as of December 31, 2017 and 2016, excludes deferred tax assets related to uncertainty in income taxes of $1.8 million and $1.0 million, respectively. As of December 31, 2017 and 2016, the net amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate for continuing operations was $15.5 million and $7.8 million, respectively.

For the year ended December 31, 2017, we recognized $0.1 million of interest income related to unrecognized tax benefits in our income statement. For the years ended December 31, 2016 and 2015, we recognized no interest related to unrecognized tax benefits in our income statements. For the years ended December 31, 2017, 2016, and 2015, we recognized no penalties related to unrecognized tax benefits in our income statements. For the year ended December 31, 2017, we had $0.2 million of interest accrued and no penalties accrued related to unrecognized tax benefits on our balance sheets. For the year ended December 31, 2016, we had $0.1 million of interest accrued and no penalties accrued related to unrecognized tax benefits on our balance sheets.

We do not anticipate any significant increases or decreases in the total amounts of unrecognized tax benefits within the next 12 months.

We file income tax returns in the United States federal jurisdiction and state tax returns based on income in our major state operating jurisdictions of Wisconsin, Illinois, Michigan, and Minnesota. We also file tax returns in other state and local jurisdictions with varying statutes of limitations. As of December 31, 2017, we were subject to examination by federal as well as by state or local tax authorities for the 2013 through 2017 tax years in our major state operating jurisdictions as follows:

Jurisdiction	Year
Federal	2014-2017
Illinois	2013-2017
Michigan	2015-2017
Minnesota	2014-2017
Wisconsin	2013-2017

NOTE 15—FAIR VALUE MEASUREMENTS

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

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

	December 31, 2016			
(in millions)	Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	$ 2.3	$ 22.4	$ —	$ 24.7
FTRs	—	—	2.0	2.0
Coal contracts	—	0.1	—	0.1
Total derivative assets	$ 2.3	$ 22.5	$ 2.0	$ 26.8
Investments held in rabbi trust	$ 103.9	$ —	$ —	$ 103.9
Derivative liabilities				
Natural gas contracts	$ —	$ 0.2	$ —	$ 0.2
Coal contracts	—	1.4	—	1.4
Total derivative liabilities	$ —	$ 1.6	$ —	$ 1.6

The derivative assets and liabilities listed in the tables above include options, swaps, futures, physical commodity contracts, and other instruments used to manage market risks related to changes in commodity prices. They also include FTRs, which are used to manage electric transmission congestion costs in the MISO Energy Markets. See Note 16, Derivative Instruments, for more information.

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

(in millions)	2017	2016	2015
Balance at the beginning of the period	**$ 2.0**	$ 2.0	$ (6.9)
Realized and unrealized losses	**—**	(0.2)	(10.7)
Purchases	**6.9**	7.1	9.8
Sales	**—**	(0.2)	(0.1)
Settlements	**(6.9)**	(6.7)	5.2
Transfers out of Level 3	**—**	—	4.7
Balance at the end of the period	**$ 2.0**	$ 2.0	$ 2.0

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

Fair Value of Financial Instruments

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

	2017		2016	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	**$ 3,249.6**	**$ 3,499.1**	$ 3,065.7	$ 3,164.7

NOTE 16—DERIVATIVE INSTRUMENTS

The following table shows our derivative assets and derivative liabilities:

	December 31, 2017		December 31, 2016	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Other current				
Natural gas contracts	**$ 4.3**	**$ 6.6**	$ 22.3	$ 0.2
Petroleum products contracts	**0.3**	**—**	—	—
FTRs	**2.0**	**—**	2.0	—
Coal contracts	**—**	**0.5**	—	0.9
Total other current	**$ 6.6**	**$ 7.1**	$ 24.3	$ 1.1
Other long-term				
Natural gas contracts	**$ 0.1**	**$ 1.1**	$ 2.4	$ —
Coal contracts	**0.4**	**—**	0.1	0.5
Total other long-term	**$ 0.5**	**$ 1.1**	$ 2.5	$ 0.5
Total	**$ 7.1**	**$ 8.2**	$ 26.8	$ 1.6

Our estimated notional sales volumes and realized gains (losses) were as follows for the years ended:

	December 31, 2017		December 31, 2016		December 31, 2015	
(in millions)	Volume	Gains (Losses)	Volume	Gains (Losses)	Volume	Gains (Losses)
Natural gas contracts	**77.2 Dth**	**$ (5.9)**	92.9 Dth	$ (37.7)	85.2 Dth	$ (55.0)
Petroleum products contracts	**1.3 gallons**	**0.1**	4.4 gallons	(0.6)	7.9 gallons	(3.4)
FTRs	**9.1 MWh**	**6.4**	8.4 MWh	6.0	9.0 MWh	3.3
Total		**$ 0.6**		$ (32.3)		$ (55.1)

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

	December 31, 2017		December 31, 2016	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Gross amount recognized on the balance sheet	$ 7.1	$ 8.2	$ 26.8	$ 1.6
Gross amount not offset on the balance sheet	(3.3)	(6.1) *	(0.2)	(0.2)
Net amount	**$ 3.8**	**$ 2.1**	$ 26.6	$ 1.4

* Includes cash collateral posted of $2.8 million as of December 31, 2017.

As of December 31, 2017 and 2016, we had posted cash collateral of $9.4 million and $16.4 million, respectively. Certain of our derivative and non-derivative commodity instruments contain provisions that could require "adequate assurance" in the event of a material change in our creditworthiness, or the posting of additional collateral for instruments in net liability positions, if triggered by a decrease in credit ratings. The aggregate fair value of all derivative instruments with specific credit risk-related contingent features that were in a net liability position at December 31, 2017 and 2016, was $3.7 million and $0.2 million, respectively. At December 31, 2017 and 2016, we had not posted any cash collateral related to the credit risk-related contingent features of these commodity instruments. If all of the credit risk-related contingent features contained in derivative instruments in a net liability position had been triggered at December 31, 2017, we would have been required to post collateral of $2.7 million. At December 31, 2016, we would not have been required to post any collateral.

NOTE 17—GUARANTEES

The following table shows our outstanding guarantees:

		Expiration		
(in millions)	Total Amounts Committed at December 31, 2017	Less Than 1 Year	1 to 3 Years	Over 3 Years
Guarantees supporting commodity transactions of subsidiaries (1)	$ 133.7	$ 59.7	$ 5.0	$ 69.0
Standby letters of credit (2)	22.2	22.0	0.2	—
Other guarantees (3)	22.2	—	10.0	12.2
Total guarantees	**$ 178.1**	$ 81.7	$ 15.2	$ 81.2

(1) Consists of (a) $5.0 million and $5.0 million to support the business operations of WBS and PDL, respectively; and (b) $94.1 million and $29.6 million related to natural gas supply at MERC and MGU, respectively. These amounts are not reflected on our balance sheets.

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

(3) Consists of (a) $12.2 million to support PDL's future payment obligations related to its distributed solar generation projects, of which $6.6 million is covered by a reciprocal guarantee from a third party that is not reflected on our balance sheets and (b) $10.0 million related to the sale of a nonregulated retail marketing business previously owned by us, of which an insignificant liability was recorded.

NOTE 18—EMPLOYEE BENEFITS

Pension and Other Postretirement Employee Benefits

Through December 31, 2016, we maintained a noncontributory, qualified pension plan sponsored by WBS that covered the majority of our employees. Effective January 1, 2017, that plan was split into six separate plans. While the split did not impact our pension benefit obligation, federal regulations required a different allocation of assets among the new plans. We maintain several unfunded non-qualified retirement plans and our subsidiaries maintain noncontributory, qualified pension plans.

In addition, we and our subsidiaries offer multiple OPEB plans to employees. The benefits for a portion of these plans are funded through irrevocable trusts, as allowed for income tax purposes. WEC Energy Group also offers medical, dental, and life insurance benefits to active employees and their dependents. We expense the costs of these benefits as incurred.

The defined benefit pension plans are closed to all new hires. In addition, the service accruals for the defined benefit pension plans were frozen for non-union employees as of January 1, 2013. These employees receive an annual company contribution to their 401(k) savings plan, which is calculated based on age, wages, and full years of vesting service as of December 31 each year. In October 2017, we remeasured the obligations of our OPEB plan as a result of a plan design change to move all participants to the same Medicare Advantage plan design starting January 1, 2018.

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

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

	Pension Costs		OPEB Costs	
(in millions)	**2017**	**2016**	**2017**	**2016**
Change in benefit obligation				
Obligation at January 1	**$ 1,297.6**	$ 1,602.7	**$ 408.4**	$ 458.6
Service cost	**26.0**	27.9	**13.9**	15.8
Interest cost	**52.1**	54.5	**16.3**	18.8
Net transfer to/from affiliates	**—**	(301.2) [2]	**—**	(28.4) [2]
Plan amendments	**—**	—	**(27.1)**	(18.9)
Actuarial loss (gain)	**79.4**	27.9	**1.6**	(21.4)
Participant contributions	**—**	—	**5.9**	6.0
Benefit payments	**(95.8)**	(114.2)	**(24.6)**	(22.1)
Obligation at December 31	**$ 1,359.3**	$ 1,297.6	**$ 394.4**	$ 408.4
Change in fair value of plan assets				
Fair value at January 1	**$ 1,017.2**	$ 1,304.6	**$ 419.6**	$ 428.3
Actual return on plan assets	**171.9**	82.8	**50.4**	27.5
Employer contributions	**68.8**	2.3	**1.4**	0.1
Net transfer to/from affiliates	**36.5** [1]	(258.3) [2]	**0.2** [1]	(20.2) [2]
Participant contributions	**—**	—	**5.9**	6.0
Benefit payments	**(95.8)**	(114.2)	**(24.6)**	(22.1)
Fair value at December 31	**$ 1,198.6**	$ 1,017.2	**$ 452.9**	$ 419.6
Funded status at December 31	**$ (160.7)**	$ (280.4)	**$ 58.5**	$ 11.2

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

[2] Benefit obligations and plan assets were moved along with our employees who were transferred to/from affiliated entities. Effective January 1, 2016, we transferred our ownership in WBS to WEC Energy Group. The benefit obligations and plan assets related to WBS employees were also transferred at that time. See Note 4, Related Parties, for more information.

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

	Pension Costs		OPEB Costs	
(in millions)	**2017**	**2016**	**2017**	**2016**
Other long-term assets	**$ 29.5**	$ —	**$ 78.1**	$ 31.7
Pension and OPEB obligations	**190.2**	280.4	**19.6**	20.5
Total net assets (liabilities)	**$ (160.7)**	$ (280.4)	**$ 58.5**	$ 11.2

The accumulated benefit obligation for the defined benefit pension plans was $1,255.7 million and $1,181.2 million at December 31, 2017 and 2016, respectively.

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

(in millions)	2017	2016
Projected benefit obligation	**$ 529.8**	$ 1,297.6
Accumulated benefit obligation	**481.1**	1,181.2
Fair value of plan assets	**339.6**	1,017.2

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

	Pension Costs		OPEB Costs	
(in millions)	2017	2016	2017	2016
Accumulated other comprehensive income (loss) (pre-tax) [(1)]				
Net actuarial loss (gain)	**$ 28.2**	$ 37.1	**$ (1.6)**	$ (1.6)
Prior service credits	**—**	—	**(0.2)**	(0.1)
Total	**$ 28.2**	$ 37.1	**$ (1.8)**	$ (1.7)
Net regulatory assets (liabilities) [(2)]				
Net actuarial loss (gain)	**$ 493.9**	$ 547.5	**$ (20.1)**	$ 1.4
Prior service costs (credits)	**8.8**	10.5	**(102.1)**	(85.6)
Total	**$ 502.7**	$ 558.0	**$ (122.2)**	$ (84.2)

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

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

The following table shows the estimated amounts that will be amortized into net periodic benefit cost during 2018:

(in millions)	Pension Costs	OPEB Costs
Net actuarial loss	$ 48.8	$ 1.4
Prior service costs (credits)	1.7	(12.8)
Total 2018 – estimated amortization	$ 50.5	$ (11.4)

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

	Pension Costs			OPEB Costs		
(in millions)	2017	2016	2015	2017	2016	2015
Service cost	**$ 26.0**	$ 27.9	$ 29.4	**$ 13.9**	$ 15.8	$ 22.4
Interest cost	**52.1**	54.4	67.4	**16.3**	18.8	20.8
Expected return on plan assets	**(78.5)**	(75.2)	(105.4)	**(30.2)**	(28.8)	(31.7)
Loss on plan settlement	**3.0**	9.9	1.2	**—**	—	—
Plan curtailment	**—**	—	(0.3)	**—**	—	—
Amortization of prior service cost (credit)	**1.7**	1.7	2.0	**(10.7)**	(8.1)	(10.3)
Amortization of net actuarial loss	**45.6**	46.7	50.2	**2.9**	5.6	8.9
Net periodic benefit cost (credit)	**$ 49.9**	$ 65.4	$ 44.5	**$ (7.8)**	$ 3.3	$ 10.1

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

	Pension		OPEB	
	2017	2016	2017	2016
Discount rate	**3.69%**	4.19%	**3.62%**	4.09%
Rate of compensation increase	**4.00%**	4.00%	**N/A**	N/A
Assumed medical cost trend rate (Pre 65)	N/A	N/A	**6.50%**	7.00%
Ultimate trend rate	N/A	N/A	**5.00%**	5.00%
Year ultimate trend rate is reached	N/A	N/A	**2024**	2021
Assumed medical cost trend rate (Post 65)	N/A	N/A	**6.00%**	7.00%
Ultimate trend rate	N/A	N/A	**5.00%**	5.00%
Year ultimate trend rate is reached	N/A	N/A	**2028**	2021

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

	Pension Costs		
	2017	**2016**	**2015**
Discount rate	**4.13%**	4.26%	4.08%
Expected return on assets	**7.25%**	7.25%	7.75%
Rate of compensation increase	**4.00%**	4.00%	4.23%

	OPEB Costs		
	2017	**2016**	**2015**
Discount rate	**4.00%**	4.34%	4.00%
Expected return on assets	**7.25%**	7.25%	7.75%
Assumed medical cost trend rate (Pre 65/Post 65)	**7.00%**	7.50%	6.00%
Ultimate trend rate	**5.00%**	5.00%	5.00%
Year ultimate trend rate is reached	**2021**	2021	2023

WEC Energy Group consults with its investment advisors on an annual basis to help forecast expected long-term returns on plan assets by reviewing historical returns as well as calculating expected total trust returns using the weighted-average of long-term market returns for each of the major target asset categories utilized in the fund. For 2018, the expected return on assets assumption for the pension and OPEB plans is 7.25%.

Assumed health care cost trend rates have a significant effect on the amounts reported by us for health care plans. For the year ended December 31, 2017, a one-percentage-point change in assumed health care cost trend rates would have had the following effects:

(in millions)	**1% Increase**	**1% Decrease**
Effect on total of service and interest cost components of net periodic postretirement health care benefit cost	$ 4.6	$ (3.6)
Effect on health care component of the accumulated postretirement benefit obligations	16.3	(11.9)

Plan Assets

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

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

Our pension plan's assets are invested in a corporate pension trust with a target asset allocation of 45% equity investments, 45% fixed income investments, and 10% private equity and real estate investments. Our two largest OPEB trusts have target asset allocations of 45% equity investments and 55% fixed income, and 50% equity investments and 50% fixed income, respectively. Equity securities include investments in large-cap, mid-cap, and small-cap companies primarily located in the United States. Fixed income securities include corporate bonds of companies from diversified industries, mortgage and other asset backed securities, commercial paper, and United States Treasuries.

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

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

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

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

	December 31, 2016							
	Pension Plan Assets				OPEB Plan Assets			
(in millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Asset Class								
Cash and cash equivalents	$ 1.8	$ 26.5	$ —	$ 28.3	$ 18.7	$ 0.7	$ —	$ 19.4
Equity securities:								
United States Equity	131.1	0.1	—	131.2	14.4	—	—	14.4
International Equity	25.0	0.5	—	25.5	0.8	0.2	—	1.0
Fixed income securities: *								
United States Bonds	—	209.4	0.6	210.0	—	59.3	—	59.3
International Bonds	—	27.8	—	27.8	—	3.4	—	3.4
	157.9	264.3	0.6	422.8	33.9	63.6	—	97.5
Investments measured at net asset value				594.4				322.1
Total	$ 157.9	$ 264.3	$ 0.6	$ 1,017.2	$ 33.9	$ 63.6	$ —	$ 419.6

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

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

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

	U.S. Bonds
(in millions)	Pension
Beginning balance at January 1, 2016	$ —
Purchases	0.6
Ending balance at December 31, 2016	$ 0.6

Cash Flows

We expect to contribute $0.7 million to the pension plans and $0.5 million to the OPEB plans in 2018, dependent upon various factors affecting us, including our liquidity position and the effects of the new Tax Legislation.

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

(in millions)	Pension	OPEB
2018	$ 94.2	$ 20.8
2019	97.6	22.0
2020	102.7	22.1
2021	103.7	23.4
2022	98.8	24.5
2023 through 2027	458.0	133.8

Savings Plans

WEC Energy Group sponsors a 401(k) savings plan which allows substantially all of our full-time employees to contribute a portion of their pre-tax and/or after-tax income in accordance with plan-specified guidelines. A percentage of employee contributions are matched by us through a contribution into the employee's savings plan account, up to certain limits. Certain employees participate in a defined contribution pension plan, in which amounts are contributed to an employee's savings plan account based on the employee's wages, age, and years of service. Our share of the total costs incurred under all of these plans was $21.7 million in 2017, $19.0 million in 2016, and $33.8 million in 2015.

NOTE 19—INVESTMENT IN AMERICAN TRANSMISSION COMPANY

Our electric transmission segment consists of WPSI’s ownership interest in ATC, which was approximately 34% at December 31, 2017. In January 2018, we transferred our ownership in WPSI, which held our ownership interest in ATC, to another subsidiary of WEC Energy Group. ATC is a for-profit, transmission-only company regulated by the FERC for cost of service and certain state regulatory commissions for routing and siting of transmission-related projects. The following table provides a reconciliation of the changes in our investment in ATC:

(in millions)	2017	2016	2015
Balance at January 1	**$ 600.2**	$ 550.4	$ 536.7
Add: Earnings from equity method investment	**93.8**	82.2	70.6
Add: Capital contributions	**34.1**	23.9	6.8
Less: Distributions received	**107.0** *	56.2	63.7
Less: Other	**—**	0.1	—
Balance at December 31	**$ 621.1**	$ 600.2	$ 550.4

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

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

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

(in millions)	2017	2016	2015
Charges to ATC for services and construction	**$ 6.2**	$ 8.6	$ 10.3
Charges from ATC for network transmission services	**107.8**	109.4	101.3
Refund from ATC per FERC ROE order	**(8.9)**	—	—

As of December 31, 2017 and 2016, our balance sheets included the following receivables and payables related to ATC:

(in millions)	2017	2016
Accounts receivable		
Services provided to ATC	**$ 0.7**	$ 1.1
Accounts payable		
Services received from ATC	**9.0**	8.8

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

(in millions)	2017	2016	2015
Income statement data			
Revenues	**$ 721.7**	$ 650.8	$ 615.8
Operating expenses	**345.0**	322.5	319.3
Other expense	**104.1**	95.5	96.1
Net income	**$ 272.6**	$ 232.8	$ 200.4

(in millions)	December 31, 2017	December 31, 2016
Balance sheet data		
Current assets	**$ 87.7**	$ 75.8
Noncurrent assets	**4,598.9**	4,312.9
Total assets	**$ 4,686.6**	$ 4,388.7
Current liabilities	**$ 767.2**	$ 495.1
Long-term debt	**1,790.6**	1,865.3
Other noncurrent liabilities	**240.3**	271.5
Shareholders' equity	**1,888.5**	1,756.8
Total liabilities and shareholders' equity	**$ 4,686.6**	$ 4,388.7

NOTE 20—SEGMENT INFORMATION

At December 31, 2017, we reported five segments, which are described below.

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

- The Illinois segment includes the natural gas utility and non-utility operations of PGL and NSG.

- The other states segment includes the natural gas utility and non-utility operations of MERC and MGU.

- Through December 31, 2017, the electric transmission investment segment included our approximate 34% ownership interest in ATC, a for-profit, electric transmission company regulated by the FERC and certain state regulatory commissions. In January 2018, we transferred our ownership in WPSI, which held our ownership interest in ATC, to another subsidiary of WEC Energy Group. See Note 4, Related Parties, for more information.

- The corporate and other segment includes the operations of the Integrys holding company, the PELLC holding company, WBS, PDL, and ITF. Effective January 1, 2016, we transferred our ownership in WBS to WEC Energy Group. See Note 4, Related Parties, for more information. The sale of ITF was also completed in the first quarter of 2016. See Note 3, Dispositions, for more information on the sale of ITF.

All of our operations and assets are located within the United States. The following tables show summarized financial information related to our reportable segments for the years ended December 31, 2017, 2016, and 2015.

	Regulated Operations							
2017 *(in millions)*	**Wisconsin**	**Illinois**	**Other States**	**Electric Transmission Investment**	**Total Regulated Operations**	**Corporate and Other**	**Reconciling Eliminations**	**Integrys Holding Consolidated**
External revenues	**$ 1,485.4**	**$1,355.5**	**$ 411.2**	**$ —**	**$ 3,252.1**	**$ 12.8**	**$ —**	**$ 3,264.9**
Other operation and maintenance	**435.7**	**471.3**	**101.2**	**—**	**1,008.2**	**9.4**	**—**	**1,017.6**
Depreciation and amortization	**139.3**	**152.6**	**24.8**	**—**	**316.7**	**3.6**	**—**	**320.3**
Operating income (loss)	**296.9**	**273.0**	**54.2**	**—**	**624.1**	**(0.3)**	**—**	**623.8**
Equity in earnings of transmission affiliate	**—**	**—**	**—**	**93.8**	**93.8**	**—**	**—**	**93.8**
Interest expense	**54.3**	**45.0**	**8.7**	**—**	**108.0**	**40.1**	**(4.1)**	**144.0**
Capital expenditures	**335.8**	**545.2**	**74.5**	**—**	**955.5**	**4.5**	**—**	**960.0**
Total assets	**4,741.3**	**5,823.3**	**1,045.9**	**643.7**	**12,254.2**	**599.6**	**(83.0)**	**12,770.8**

	Regulated Operations							
2016 *(in millions)*	**Wisconsin**	**Illinois**	**Other States**	**Electric Transmission Investment**	**Total Regulated Operations**	**Corporate and Other**	**Reconciling Eliminations**	**Integrys Holding Consolidated**
External revenues	$ 1,448.2	$1,242.2	$ 376.6	$ —	$ 3,067.0	$ 21.9	$ —	$ 3,088.9
Other operation and maintenance	493.2	530.6	113.9	—	1,137.7	19.2	—	1,156.9
Depreciation and amortization	124.1	134.0	21.1	—	279.2	4.3	—	283.5
Operating income (loss)	263.5	194.1	46.2	—	503.8	(7.8)	—	496.0
Equity in earnings of transmission affiliate	—	—	—	82.2	82.2	—	—	82.2
Interest expense	48.1	38.9	8.5	—	95.5	46.7	(8.0)	134.2
Capital expenditures	311.2	293.2	59.5	—	663.9	1.7	—	665.6
Total assets	4,639.4	5,392.7	966.2	600.2	11,598.5	464.1	(233.8)	11,828.8

	Regulated Operations							
2015 *(in millions)*	**Wisconsin**	**Illinois**	**Other States**	**Electric Transmission Investment**	**Total Regulated Operations**	**Corporate and Other**	**Reconciling Eliminations**	**Integrys Holding Consolidated**
External revenues	$ 1,483.3	$1,253.6	$ 399.6	$ —	$ 3,136.5	$ 82.6	$ —	$ 3,219.1
Other operation and maintenance	488.7	465.1	105.9	—	1,059.7	4.9	—	1,064.6
Depreciation and amortization	121.0	125.8	19.5	—	266.3	26.2	—	292.5
Merger costs	5.2	6.3	0.1	—	11.6	75.3	—	86.9
Impairment losses	—	—	—	—	—	47.3	—	47.3
Operating income (loss)	227.5	209.6	40.4	—	477.5	(122.9)	—	354.6
Equity in earnings of transmission affiliate	—	—	—	70.6	70.6	—	—	70.6
Interest expense	58.3	38.8	10.1	—	107.2	53.4	(9.5)	151.1
Capital expenditures	371.0	368.3	53.0	—	792.3	95.6	—	887.9
Total assets	4,439.9	5,169.6	897.4	550.4	11,057.3	932.7	(411.8)	11,578.2

NOTE 21—COMMITMENTS AND CONTINGENCIES

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

Unconditional Purchase Obligations

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

The following table shows our minimum future commitments related to these purchase obligations as of December 31, 2017, including those of our subsidiaries.

			Payments Due By Period					
(in millions)	Date Contracts Extend Through	Total Amounts Committed	2018	2019	2020	2021	2022	Later Years
Electric utility:								
Purchased power	2027	$ 567.0	$ 85.2	$ 57.5	$ 59.8	$ 58.7	$ 53.8	$ 252.0
Coal supply and transportation	2024	126.2	91.1	18.1	9.9	2.1	2.1	2.9
Natural gas utility supply and transportation	2048	1,228.4	197.5	185.4	143.2	81.7	58.8	561.8
Total		$ 1,921.6	$ 373.8	$ 261.0	$ 212.9	$ 142.5	$ 114.7	$ 816.7

Operating Leases

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

Rental expense attributable to operating leases was $3.8 million, $2.4 million, and $10.8 million in 2017, 2016, and 2015, respectively.

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

Year Ending December 31	Payments *(in millions)*
2018	$ 6.0
2019	5.8
2020	5.6
2021	5.8
2022	6.0
Later years	51.2
Total	$ 80.4

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, nitrogen oxide, fine particulates, mercury, and GHGs; water intake and discharges; disposal of coal combustion products such as fly ash; and remediation of impacted properties, including former manufactured gas plant sites.

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

- the development of additional sources of renewable electric energy supply;
- the addition of improvements for water quality matters such as treatment technologies to meet regulatory discharge limits and improvements to our cooling water intake systems;
- the addition of emission control equipment to existing facilities to comply with ambient air quality standards and federal clean air rules;

- the protection of wetlands and waterways, threatened and endangered species, and cultural resources associated with utility construction projects;
- the retirement of old coal-fired power plants and conversion to modern, efficient, natural gas generation, super-critical pulverized coal generation, and/or replacement with renewable generation;
- the beneficial use of ash and other products from coal-fired units; and
- the remediation of former manufactured gas plant sites.

Air Quality

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, located in Marathon County, Wisconsin, to be in compliance. In December 2017, the EPA finalized the designation, and Marathon County has been designated attainment. We continue to believe that 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

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. In December 2017, the EPA designated all the counties along Wisconsin's Lake Michigan shoreline, except Brown, Kewaunee, Marinette, and Oconto Counties, as either partial or full nonattainment. 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. Although we will not know the potential impacts for complying with the 2015 ozone NAAQS until the designations are final, which is expected from the EPA in April 2018, and until the state prepares a draft attainment plan, we believe we are well positioned to meet the requirements associated with the ozone standard and do not expect to incur significant costs to comply.

Climate Change

In 2015, the EPA issued a final rule regulating GHG emissions from existing generating units, referred to as the Clean Power Plan, 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 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 of 41% 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. 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 proposed rulemaking to repeal the CPP. In December 2017, the EPA issued an advanced notice of proposed rulemaking to 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 to implement the CPP.

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 WEC Energy Group's 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. As a result of WEC Energy Group's generation reshaping plan, we expect to retire approximately 308 MW of coal generation by 2020, including the Pulliam power plant and the jointly-owned Edgewater Unit 4 generation units. See Note 6, Property, Plant, and Equipment, for more information. In addition, we are evaluating our goal, and possible subsequent actions, with respect to national and international efforts to reduce future GHG emissions in order to limit future global temperature increases to less than two degrees Celsius.

We are required to report our CO_2 equivalent emissions from our electric generating facilities under the EPA Greenhouse Gases Reporting Program. For 2016, we reported aggregated CO_2 equivalent emissions of approximately 5.2 million metric tonnes to the EPA. Based upon our preliminary analysis of the data, we estimate that we will report CO_2 equivalent emissions of approximately 5.7 million metric tonnes to the EPA for 2017. The level of CO_2 and other GHG emissions varies from year to year and is dependent on the level of electric generation and mix of fuel sources, which is determined primarily by demand, the availability of the generating units, the unit cost of fuel consumed, and how our units are dispatched by MISO.

We are also required to report CO_2 equivalent amounts related to the natural gas that our natural gas utilities distribute and sell. For 2016, we reported aggregated CO_2 equivalent emissions of approximately 17.6 million metric tonnes to the EPA. Based upon our preliminary analysis of the data, we estimate that we will report CO_2 equivalent emissions of approximately 16.8 million metric tonnes to the EPA for 2017.

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.

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 retire Pulliam Units 7 and 8 as early as late 2018. Therefore, we are not planning to make alterations to the existing water intake at Pulliam Units 7 and 8. We do expect that limited studies will be required to support the future WDNR IM BTA determinations for Weston Unit 2. Based on preliminary discussions with the WDNR, we anticipate physical modifications will not be required 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 to address entrainment mortality (EM) reduction on a site-specific basis taking into consideration several factors. Due to our plans to retire Pulliam Units 7 and 8, we do not believe that BTA determinations for EM will be necessary for these facilities. For Weston Units 2 through 4, BTA determinations to address EM reduction requirements will not be made until the discharge permits are renewed. Until that time, we cannot yet determine what, if any, intake structure or operational modifications will be required to meet the new EM BTA requirements at Weston Unit 2. Weston Units 3 and 4 have existing cooling towers that meet EM BTA requirements. We also expect that limited studies to support WDNR BTA determinations will be conducted at the Weston facility. During 2018, we will continue to evaluate options to address the EM BTA requirements at Weston Unit 2.

We have also provided information to the WDNR about planned unit retirements. For Pulliam Units 7 and 8, we submitted our 2016 and 2017 entrainment studies to the WDNR in December 2017, with the application to renew our existing discharge permit.

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. Various petitions challenging the rule were consolidated and are pending in the United States Fifth Circuit Court of Appeals. 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. While the ELG compliance deadlines are postponed, the WDNR has 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 has 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 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 Weston Unit 3. We are beginning preliminary engineering for compliance with the rule and estimate approximately $20 million will be required to design and install a dry bottom ash transport system for Weston Unit 3. This estimate reflects the planned retirements of certain of our generation plants as a result of WEC Energy Group's generation reshaping plan discussed in Climate Change above.

Land Quality

Manufactured Gas Plant Remediation

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

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

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

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

(in millions)	**2017**	2016
Regulatory assets	**$ 598.9**	$ 633.2
Reserves for future remediation	**557.5**	578.2

Renewables, Efficiency, and Conservation

Wisconsin Legislation

In 2005, Wisconsin enacted Act 141, which established a goal that 10% of all electricity consumed in Wisconsin be generated by renewable resources by December 31, 2015. WPS achieved a renewable energy percentage of 9.74% and met its compliance requirements by constructing various wind parks and by also relying on renewable energy purchases. We continue to review our renewable energy portfolios and acquire cost-effective renewables as needed to meet our requirements on an ongoing basis. The PSCW administers the renewable program related to Act 141, and WPS funds the program, along with other utilities, based on 1.2% of its annual operating revenues.

Enforcement and Litigation Matters

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

Manlove Field Matter

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

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

Consent Decrees

Wisconsin Public Service Corporation Consent Decree – Weston and Pulliam Power Plants

In November 2009, the EPA issued 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 power plants from 1994 to 2009. WPS entered into a Consent Decree with the EPA resolving this NOV. This Consent Decree was entered by the United States District Court for the Eastern District of Wisconsin in March 2013.

The final Consent Decree includes:

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

The Consent Decree also contains requirements to refuel, repower, and/or retire certain Weston and Pulliam units. Effective June 1, 2015, WPS retired Weston Unit 1 and Pulliam Units 5 and 6. In May 2016, the EPA approved WPS's proposed revision to update requirements reflecting the conversion of Weston Unit 2 from coal to natural gas fuel, and also proposed revisions to the list of beneficial environmental projects required by the Consent Decree. WPS anticipates retirement of the remaining Pulliam units in 2018. See Note 6, Property, Plant, and Equipment, for more information about the retirement.

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

Joint Ownership Power Plants Consent Decree – Columbia and Edgewater

In December 2009, the EPA issued 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 final Consent Decree includes:

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

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 September 30, 2018. See Note 6, Property, Plant, and Equipment, for more information about the retirement.

NOTE 22—SUPPLEMENTAL CASH FLOW INFORMATION

(in millions)	2017	2016	2015
Cash (paid) for interest, net of amount capitalized	**$ (137.7)**	$ (137.5)	$ (150.0)
Cash received for income taxes, net	**58.9**	149.6	42.5
Significant non-cash transactions:			
Accounts payable related to construction costs	**141.9**	161.0	165.4
Transfer of net assets to UMERC [(1)]	**20.6**	—	—
Increase (decrease) in restricted cash from the sale (purchase) of investments held in the rabbi trust	**4.6**	(59.2)	(70.0)
Non-cash equity transfer of our ownership in WBS to WEC Energy Group	**—**	73.0	—
Note receivable received related to the sale of AMP Trillium LLC [(2)]	**—**	—	12.0
Capital assets received related to the sale of AMP Trillium LLC [(2)]	**—**	—	6.3
ITF fueling station sale financed with note receivable	**—**	—	2.8
Purchase of a natural gas distribution business in Minnesota financed with note payable	**—**	—	2.6

(1) See Note 4, Related Parties, for more information on this transaction.

(2) ITF owned a 30% interest in AMP Trillium LLC. See Note 3, Dispositions, for more information on the sale of ITF.

At December 31, 2017 and 2016, restricted cash of $19.7 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 rabbi trust and represents a portion of the required funding that was triggered by the announcement of the WEC Merger. 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 23—REGULATORY ENVIRONMENT

Tax Cuts and Jobs Act of 2017

Our regulated utilities deferred for return to ratepayers, through future refunds, bill credits, riders, or reductions in other regulatory assets, the estimated tax benefit of $1,069 million related to the Tax Legislation that was signed into law in December 2017. This tax benefit resulted from the revaluation of deferred taxes related to our regulated operations. See Note 14, Income Taxes, for more information.

Wisconsin Public Service Corporation

2018 and 2019 Rates

During April 2017, WPS, along with WE and WG, filed an application with the PSCW for approval of a settlement agreement they made with several of their commercial and industrial customers regarding 2018 and 2019 base rates. In September 2017, the PSCW issued an order that approved the settlement agreement, which freezes base rates through 2019 for WPS's electric and natural gas customers. Based on the PSCW order, the authorized ROE for WPS remains at 10.0%, and WPS's current capital cost structure will remain unchanged through 2019. Various intervenors had filed requests for rehearing, all of which have been denied.

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

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

Acquisition of a Wind Energy Generation Facility in Wisconsin

In October 2017, WPS, along with two other unaffiliated utilities, entered into an agreement to purchase the Forward Wind Energy Center, which consists of 86 wind turbines located in Wisconsin with a total capacity of 129 MW. The FERC approved the transaction on January 16, 2018, and the PSCW approved the transaction on March 20, 2018. The transaction is expected to close in the spring of 2018. See Note 2, Acquisitions, for more information.

Natural Gas Storage Facilities in Michigan

In January 2017, WEC Energy Group signed an agreement for the acquisition of Bluewater. Bluewater owns natural gas storage facilities in Michigan that would provide a portion of the current storage needs for WPS's natural gas utility operations. As a result of this agreement, WPS, along with WE and WG, filed a request with the PSCW in February 2017 for a declaratory ruling on various items associated with the storage facilities. In the filing, WPS requested that the PSCW review and confirm the reasonableness and prudency of its potential long-term storage service agreement and interstate natural gas transportation contract related to the storage facilities. WPS also requested approval to amend WEC Energy Group's AIA to ensure WBS and WEC Energy Group's other subsidiaries could provide services to the storage facilities. During June 2017, the PSCW granted, subject to various conditions, these declarations and approvals, and WEC Energy Group acquired Bluewater on June 30, 2017. In September 2017, WPS entered into the long-term service agreement for the natural gas storage, which was then approved by the PSCW in November 2017. See Note 2, Acquisitions, for more information.

2016 Wisconsin Rate Order

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

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

2015 Wisconsin Rate Order

In April 2014, WPS initiated a rate proceeding with the PSCW. In December 2014, the PSCW issued a final written order for WPS, effective January 1, 2015. It authorized a net retail electric rate increase of $24.6 million and a net retail natural gas rate decrease of $15.4 million, reflecting a 10.2% ROE. The order authorized a common equity component average of 50.28%. The PSCW approved a change in rate design for WPS, which included higher fixed charges to better match the related fixed costs of providing service. In addition, the order continued to exclude a decoupling mechanism that was terminated beginning January 1, 2014.

The primary driver of the increase in retail electric rates was higher costs of fuel for electric generation of approximately $42 million. In addition, 2015 rates included approximately $9 million of lower refunds to customers related to decoupling over-collections. In addition, WPS received approval from the PSCW to defer and amortize the undepreciated book value associated with Pulliam Units 5 and 6 and Weston Unit 1 starting with the actual retirement date, June 1, 2015, and concluding by 2023. See Note 21, Commitments and Contingencies, for more information. The PSCW allowed WPS to escrow ATC and MISO network transmission expenses for 2015 and 2016. As a result, WPS deferred as a regulatory asset the difference between actual transmission expenses and those included in rates until a future rate proceeding. Finally, the PSCW ordered that 2015 fuel costs should continue to be monitored using a 2% tolerance window.

The retail natural gas rate decrease was driven by the approximate $16 million year-over-year negative impact of decoupling refunds to and collections from customers between 2015 and 2014.

2015 Michigan Rate Order

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. 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, WPS discontinued the deferral of the Fox Energy Center costs and began amortizing this deferral along with the deferral associated with the termination of a tolling agreement related to the Fox Energy Center. WPS also received approval from the MPSC to defer and amortize 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. As a result of the formation of UMERC, WPS transferred the deferrals mentioned above, as well as its customers and property, plant, and equipment located in the Upper Peninsula of Michigan to the new utility, effective January 1, 2017. Therefore, the terms and conditions of this rate order were applicable to UMERC starting January 1, 2017. See Note 4, Related Parties, for more information on the formation of UMERC.

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

Base Rate Freeze

In June 2015, the ICC approved the WEC Merger subject to the condition that PGL and NSG will not seek increases of their base rates that would become effective earlier than two years after the close of the acquisition. This base rate freeze expired in 2017 and did not impact PGL's or NSG's ability to adjust rates through various riders or gas cost recovery mechanisms.

SMP Proceedings

In December 2015, the ICC ordered a series of stakeholder workshops to evaluate PGL's SMP. This ICC action did not impact PGL's ongoing work to modernize and maintain the safety of its natural gas distribution system, but it instead provided the ICC with an opportunity to analyze long-term elements of the program through the stakeholder workshops. The workshops were completed in March 2016. In July 2016, the ICC initiated a proceeding to review, among other things, the planning, reporting, and monitoring of the program, including the target end date for the program. In March 2017, the ICC issued an order directing that additional hearings be held before the Administrative Law Judge on certain issues to further develop the evidentiary record in the case. This proceeding resulted in a final order issued by the ICC in January 2018. The order did not have a significant impact on PGL's existing SMP design and execution.

Qualifying Infrastructure Plant Rider

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

PGL's QIP rider is subject to an annual reconciliation whereby costs are reviewed for accuracy and prudency. In March 2017, PGL filed its 2016 reconciliation with the ICC, which, along with the 2015 reconciliation, is still pending. In February 2018, PGL agreed to a settlement of the 2014 reconciliation, which includes a rate base reduction of $5.4 million and a $4.7 million refund to ratepayers. As of December 31, 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.

2015 Illinois Rate Order

In February 2014, PGL and NSG initiated a rate proceeding with the ICC. In January 2015, the ICC issued a final written order for PGL and NSG, effective January 28, 2015. The order authorized a retail natural gas rate increase of $74.8 million for PGL and $3.7 million for NSG. In February 2015, the ICC issued an amendatory order that revised the increases to $71.1 million for PGL and $3.5 million for NSG, effective February 26, 2015, to reflect the extension of bonus depreciation in 2014. The rates for PGL reflected a 9.05% ROE and a common equity component average of 50.33%. The rates for NSG reflected a 9.05% ROE and a common equity component average of 50.48%. The rate order allowed PGL and NSG to continue the use of their decoupling mechanisms and uncollectible expense true-up mechanisms. In addition, as previously discussed, PGL recovers a return on certain investments and depreciation expense through the QIP rider, and accordingly, such costs are not subject to PGL's rate order.

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.

In November 2017, the MPUC approved an interim rate order, effective January 1, 2018, authorizing a retail natural gas rate increase for MERC of $9.5 million (3.78%). In March 2018, to reflect changes in our effective tax rate as a result of the enactment of the Tax Legislation, the MPUC approved a $2.5 million reduction in our interim retail natural gas rates to $7.0 million (2.81%), effective

April 1, 2018. The interim rates reflect a 9.11% ROE and a common equity component average of 50.9%. The interim rate increase is subject to refund pending the final written rate order, which is expected in the first half of 2019.

2016 Minnesota Rate Order

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

2015 Minnesota Rate Order

In September 2013, MERC initiated a rate proceeding with the MPUC. In October 2014, the MPUC issued a final written order for MERC, effective April 1, 2015. The order authorized a retail natural gas rate increase of $7.6 million. The rates reflected a 9.35% ROE and a common equity component average of 50.31%. The order approved a deferral of customer billing system costs, for which recovery was requested in MERC's 2016 rate case. The order also approved MERC's request to continue the use of its decoupling mechanism with a 10% cap for residential and small commercial and industrial customers. The final approved rate increase was lower than the interim rates collected from customers during 2014. Therefore, MERC refunded $4.7 million to customers in 2015.

Michigan Gas Utilities Corporation

2016 Michigan Rate Order

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

NOTE 24—ACCUMULATED OTHER COMPREHENSIVE LOSS

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

(in millions)	Cash Flow Hedges	Defined Benefit Plans	Accumulated Other Comprehensive Loss
Balance at December 31, 2014	$ (3.2)	$ (24.4)	$ (27.6)
Other comprehensive loss before reclassifications	—	(3.1)	(3.1)
Amounts reclassified out of accumulated other comprehensive loss	0.7	1.6	2.3
Net 2015 other comprehensive income (loss)	0.7	(1.5)	(0.8)
Balance at December 31, 2015	(2.5)	(25.9)	(28.4)
Other comprehensive income before reclassifications	—	0.2	0.2
Amounts reclassified out of accumulated other comprehensive loss	0.6	4.3	4.9
Net 2016 other comprehensive income	0.6	4.5	5.1
Balance at December 31, 2016	(1.9)	(21.4)	(23.3)
Other comprehensive income before reclassifications	**—**	**1.0**	**1.0**
Amounts reclassified out of accumulated other comprehensive loss	**0.5**	**4.3**	**4.8**
Net 2017 other comprehensive income	**0.5**	**5.3**	**5.8**
Balance at December 31, 2017	**$ (1.4)**	**$ (16.1)**	**$ (17.5)**

NOTE 25—OTHER INCOME, NET

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

(in millions)	2017	2016	2015
Gains (losses) on investments held in rabbi trust	**$ 21.5**	$ 5.1	$ (3.3)
AFUDC – Equity	**4.2**	19.5	17.7
Interest income from parent	**2.5**	—	—
Gain on repurchase of notes	**—**	25.7	—
Federal excise tax credit	**—**	1.1	7.3
Other, net	**10.1**	0.7	7.4
Total other income, net	**$ 38.3**	$ 52.1	$ 29.1

NOTE 26—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 have completed the review of our contracts with customers and are finalizing the related financial disclosures to evaluate the impact of the amended guidance on our existing revenue recognition policies and procedures. 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. Most of our revenues are from tariff sales at our regulated utilities, which are in the scope of the new standard, excluding the revenue component related to alternative revenue programs. The revenues from these contracts are recorded at the amount of the electricity or natural gas delivered to the customer during the period.

We adopted this standard for interim and annual periods beginning January 1, 2018, as required, and used the modified retrospective method of adoption. The most significant impact to the financial statements is expected to be in the form of additional disclosures. However, we do not expect to have a cumulative-effect adjustment to record on the balance sheet as of the beginning of 2018; and therefore, do not expect to include a reconciliation of results under the new revenue recognition guidance compared with what would have been reported in 2018 under the old revenue recognition guidance. We will include disaggregated revenue disclosures by segment, major products (electric and natural gas), and customer class in the notes to consolidated financial statements, starting in 2018.

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 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. As required, we adopted this ASU for interim and annual periods beginning January 1, 2018. 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, 2020. 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. There are eight main provisions of this ASU for which current GAAP either is unclear or does not include specific guidance. As required, we adopted this ASU for interim and annual periods beginning January 1, 2018, and used a retrospective transition method. 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. 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. As required, we adopted this ASU for interim and annual periods beginning January 1, 2018. 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. 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. As required, we adopted this ASU for interim and annual periods beginning January 1, 2018. The amendments will 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. 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 rate-making treatment. The impacts of adoption will be limited to changes in classification of non-service costs in the income statements.