INTEGRYS HOLDING, INC.

FINANCIAL STATEMENTS
DECEMBER 31, 2015 AND 2014

INTEGRYS HOLDING, INC.
FINANCIAL STATEMENTS
For the Year Ended December 31, 2015
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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
IES	Integrys Energy Services, Inc.
Integrys	Integrys Holding, Inc. (previously known as Integrys Energy Group, 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
UPPCO	Upper Peninsula Power Company
WBS	WEC Business Services LLC
WEC Energy Group	WEC Energy Group, Inc.
Wisconsin Electric	Wisconsin Electric Power Company
WPS	Wisconsin Public Service Corporation
WRPC	Wisconsin River Power Company

Federal and State Regulatory Agencies

EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
ICC	Illinois Commerce Commission
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
OPEB	Other Postretirement Employee Benefits

Environmental Terms

Act 141	2005 Wisconsin Act 141
CAA	Clean Air Act
CO_2	Carbon Dioxide
GHG	Greenhouse Gas
MATS	Mercury and Air Toxics Standards
NAAQS	National Ambient Air Quality Standards
NOx	Nitrogen Oxide
SO_2	Sulfur Dioxide

Measurements

Btu	British Thermal Unit(s)
Dth	Dekatherm(s) (One Dth equals one million Btu)
MW	Megawatt(s) (One MW equals one million Watts)
MWh	Megawatt-hour(s)

Other Terms and Abbreviations

ALJ	Administrative Law Judge
AMRP	Accelerated Natural Gas Main Replacement Program
CNG	Compressed Natural Gas
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
N/A	Not Applicable
ROE	Return on Equity

FINANCIAL STATEMENTS AND NOTES

A. INDEPENDENT AUDITORS' REPORT

INDEPENDENT AUDITORS' REPORT

To the Board of Directors of Integrys Holding, Inc.

We have audited the accompanying consolidated financial statements of Integrys Holding, Inc. and its subsidiaries (the "Company"), which comprise the consolidated balance sheets as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2015, 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, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in accordance with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Milwaukee, WI
March 17, 2016

INTEGRYS HOLDING, INC.

B. CONSOLIDATED INCOME STATEMENTS

Year Ended December 31 *(in millions)*	2015	2014	2013
Operating revenues	**$ 3,219.1**	$ 4,145.6	$ 3,486.7
Operating expenses			
Cost of sales	**1,300.3**	2,130.5	1,597.7
Other operation and maintenance	**1,069.8**	1,230.6	1,115.6
Depreciation and amortization	**292.5**	290.6	266.6
Property and revenue taxes	**72.9**	67.7	67.3
Merger costs	**86.9**	10.4	—
Impairment losses	**47.3**	—	—
Gain on sale of certain PDL solar power generation plants, net of transaction costs	**(5.2)**	—	—
Gain on abandonment of PDL's Winnebago Energy Center	**—**	(5.0)	—
Gain on sale of UPPCO, net of transaction costs	—	(85.4)	—
Total operating expenses	**2,864.5**	3,639.4	3,047.2
Operating income	**354.6**	506.2	439.5
Equity in earnings of transmission affiliate	**70.6**	85.7	89.1
Other income, net	**29.1**	34.5	24.4
Interest expense	**151.1**	154.8	127.4
Other expense	**(51.4)**	(34.6)	(13.9)
Income before income taxes	**303.2**	471.6	425.6
Income tax expense	**132.0**	193.4	158.0
Net income from continuing operations	**171.2**	278.2	267.6
Discontinued operations, net of tax	**(0.8)**	1.8	87.3
Net income	**170.4**	280.0	354.9
Preferred stock dividends of subsidiary	**(2.7)**	(3.1)	(3.1)
Net income attributed to common shareholder	**$ 167.7**	$ 276.9	$ 351.8

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)***	**2015**	**2014**	**2013**
Net income	**$ 170.4**	$ 280.0	$ 354.9
Other comprehensive income (loss), net of tax			
Cash flow hedges			
Unrealized net gains arising during period, net of tax of an insignificant amount for all periods presented	**—**	—	0.7
Reclassification of net losses (gains) to net income, net of tax of $0.4 million, $1.2 million, and $3.6 million, respectively	**0.7**	(0.1)	1.4
Cash flow hedges, net	**0.7**	(0.1)	2.1
Defined benefit plans			
Pension and OPEB adjustments arising during period, net of tax of $(2.6) million, $(3.0) million, and $8.9 million, respectively	**(3.1)**	(6.0)	13.2
Amortization of pension and OPEB costs included in net periodic benefit cost, net of tax of $1.4 million, $0.8 million, and $1.7 million, respectively	**1.6**	1.7	2.4
Defined benefit plans, net	**(1.5)**	(4.3)	15.6
Other comprehensive (loss) income, net of tax	**(0.8)**	(4.4)	17.7
Comprehensive income	**169.6**	275.6	372.6
Preferred stock dividends of subsidiary	**(2.7)**	(3.1)	(3.1)
Comprehensive income attributed to common shareholder	**$ 166.9**	$ 272.5	$ 369.5

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

INTEGRYS HOLDING, INC.
D. CONSOLIDATED BALANCE SHEETS

At December 31 *(in millions, except share and per share data)*	2015	2014
Assets		
Current assets		
Cash and cash equivalents	**$ 19.4**	$ 18.0
Accounts receivable and unbilled revenues, net of reserves of $49.9 and $63.3, respectively	**471.2**	747.1
Receivables from related parties	**2.8**	—
Materials, supplies, and inventories	**328.2**	327.7
Assets held for sale	**115.1**	51.5
Prepaid taxes	**122.2**	136.2
Other current assets	**54.7**	55.5
Current assets	**1,113.6**	1,336.0
Long-term assets		
Property, plant, and equipment, net of accumulated depreciation of $3,267.9 and $3,322.0, respectively	**7,418.6**	6,827.9
Regulatory assets	**1,641.6**	1,585.3
Equity investment in transmission affiliate	**550.4**	536.7
Goodwill	**635.8**	655.4
Other long-term assets	**218.2**	256.7
Long-term assets	**10,464.6**	9,862.0
Total assets	**$ 11,578.2**	$ 11,198.0
Liabilities and Equity		
Current liabilities		
Short-term debt	**$ 305.5**	$ 317.6
Current portion of long-term debt	**100.0**	125.0
Accounts payable	**469.4**	490.7
Payables to related parties	**18.8**	—
Note payable to related party	**95.1**	—
Liabilities held for sale	**30.0**	13.8
Other current liabilities	**336.4**	393.5
Current liabilities	**1,355.2**	1,340.6
Long-term liabilities		
Long-term debt	**3,069.9**	2,924.7
Deferred income taxes	**1,664.9**	1,517.6
Deferred investment tax credits	**62.2**	60.6
Regulatory liabilities	**459.5**	508.8
Environmental remediation	**598.2**	579.9
Pension and OPEB obligations	**335.9**	274.6
Asset retirement obligations	**509.2**	479.1
Other long-term liabilities	**192.9**	161.3
Long-term liabilities	**6,892.7**	6,506.6
Commitments and contingencies (Note 20)		
Common stock – $0.01 par value; 1,000 shares authorized, issued, and outstanding at December 31, 2015 and $1 par value; 200,000,000 shares authorized; 79,963,091 shares issued; 79,534,171 shares outstanding at December 31, 2014	**—**	80.0
Additional paid in capital	**2,691.7**	2,642.2
Retained earnings	**667.0**	626.0
Accumulated other comprehensive loss	**(28.4)**	(27.6)
Shares in deferred compensation trust	**—**	(20.9)
Total common shareholder's equity	**3,330.3**	3,299.7
Preferred stock of subsidiary – $100 par value; 1,000,000 shares authorized; zero shares issued and outstanding at December 31, 2015; 511,882 shares issued and 510,495 shares outstanding at December 31, 2014	**—**	51.1
Total liabilities and equity	**$ 11,578.2**	$ 11,198.0

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)*	2015	2014	2013
Operating activities			
Net income	**$ 170.4**	$ 280.0	$ 354.9
Reconciliation to cash provided by operating activities			
Depreciation and amortization expense	**299.6**	298.7	274.5
Contributions to pension and OPEB plans	**(16.4)**	(108.8)	(77.0)
Deferred income taxes and investment tax credits, net	**159.9**	165.9	209.8
Impairment losses	**47.3**	—	—
Gain on sale of UPPCO	**—**	(86.5)	—
Loss on sale of IES's retail energy business	**—**	24.3	—
Termination of tolling agreement with Fox Energy Company LLC	**—**	—	(50.0)
Change in -			
Accounts receivable and unbilled revenues	**227.9**	136.7	(284.9)
Materials, supplies, and inventories	**(13.8)**	(120.2)	23.0
Other current assets	**(3.3)**	(15.8)	0.5
Accounts payable	**(32.4)**	13.2	132.2
Other current liabilities	**29.4**	18.4	(12.4)
Other, net	**(64.7)**	(4.5)	(15.7)
Net cash provided by operating activities	**803.9**	601.4	554.9
Investing activities			
Capital expenditures	**(887.9)**	(856.7)	(662.1)
Proceeds from the sale of UPPCO, net of cash divested	**—**	336.5	—
Proceeds from the sale of IES's retail energy business, net of cash divested	**14.0**	311.6	—
Investment in transmission affiliate	**(6.8)**	(17.0)	(13.7)
Proceeds from asset sales	**3.5**	23.0	3.6
Cash proceeds from corporate owned life insurance policies	**17.3**	—	—
Rabbi trust funding related to change in control	**(14.3)**	(115.5)	—
Withdrawal of restricted cash from Rabbi trust for qualifying payments	**15.5**	—	—
Proceeds from sale of certain PDL solar power generation plants	**47.8**	—	—
Acquisition of Fox Energy Company LLC	**—**	—	(391.6)
Acquisitions at IES	**—**	—	(15.7)
Grant received related to Crane Creek wind project	**—**	—	69.0
Other	**15.5**	(18.4)	(12.2)
Net cash used for investing activities	**(795.4)**	(336.5)	(1,022.7)
Financing activities			
Short-term debt, net	**(12.1)**	(8.4)	(156.4)
Borrowing on term credit facility	**—**	—	200.0
Repayment of term credit facility	**—**	—	(200.0)
Issuance of long-term debt	**250.0**	200.0	1,174.0
Repayment of long-term debt	**(130.1)**	(175.0)	(363.5)
Exercise of stock options	**4.1**	85.8	38.7
Purchase of common stock	**(23.9)**	(143.5)	(2.0)
Payment of dividends			
Preferred stock of subsidiary	**(2.7)**	(3.1)	(3.1)
Common stock	**(125.4)**	(216.3)	(202.6)
Redemption of WPS preferred stock	**(52.7)**	—	—
Note payable to parent	**95.1**	—	—
Other	**(9.4)**	(8.7)	(22.4)
Net cash (used for) provided by financing activities	**(7.1)**	(269.2)	462.7
Net change in cash and cash equivalents	**1.4**	(4.3)	(5.1)
Cash and cash equivalents at beginning of year	**18.0**	22.3	27.4
Cash and cash equivalents at end of year	**$ 19.4**	$ 18.0	$ 22.3

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, 2012	$ (17.7)	$ 78.3	$ 2,574.6	$ 431.5	$ (40.9)	$ 3,025.8	$ 51.1	$ 3,076.9
Net income attributed to common shareholders	—	—	—	351.8	—	351.8	—	351.8
Other comprehensive income	—	—	—	—	17.7	17.7	—	17.7
Issuance of common stock	—	1.5	78.3	—	—	79.8	—	79.8
Stock-based compensation	—	—	1.0	(0.7)	—	0.3	—	0.3
Dividends on common stock (dividends per common share of $2.72)	—	—	—	(214.6)	—	(214.6)	—	(214.6)
Shares issued to the deferred compensation trust	(6.3)	0.1	6.2	—	—	—	—	—
Other	1.0	—	0.4	(0.9)	—	0.5	—	0.5
Balance at December 31, 2013	$ (23.0)	$ 79.9	$ 2,660.5	$ 567.1	$ (23.2)	$ 3,261.3	$ 51.1	$ 3,312.4
Net income attributed to common shareholders	—	—	—	276.9	—	276.9	—	276.9
Other comprehensive loss	—	—	—	—	(4.4)	(4.4)	—	(4.4)
Issuance of common stock	—	0.1	2.3	—	—	2.4	—	2.4
Stock-based compensation	—	—	(20.9)	(0.8)	—	(21.7)	—	(21.7)
Dividends on common stock (dividends per common share of $2.72)	—	—	—	(216.3)	—	(216.3)	—	(216.3)
Shares purchased for the deferred compensation trust	(0.6)	—	—	—	—	(0.6)	—	(0.6)
Other	2.7	—	0.3	(0.9)	—	2.1	—	2.1
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**

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

G. NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2015

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) General Information—On June 29, 2015, Wisconsin Energy Corporation acquired us, and we 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 2, Merger, for more information.

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

- 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. UPPCO's electric operations in the state of Michigan prior to its sale in August 2014 are also included in this segment. See Note 4, Dispositions, for more information on the sale of UPPCO.

- Electric transmission segment – Consists of our approximate 34% ownership interest in ATC, a federally regulated electric transmission company.

- Corporate and other segment – Consists of the Integrys holding company, the PELLC holding company, WBS, PDL, and ITF. The discontinued operations of IES's retail energy business prior to its sale in November 2014 are also included in this segment. See Note 4, Dispositions, for more information on the sale of IES's retail energy business.

Our financial statements also reflect our proportionate interests in certain jointly owned utility facilities. See Note 10, 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 6, Equity Method Investments, for more information.

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.

(b) Reclassifications—During the fourth quarter of 2015, we early implemented ASU 2015-03, Simplifying the Presentation of Debt Issuance Costs. As a result, debt issuance costs of $1.9 million and $29.7 million, previously reported as other current assets and other long-term assets, respectively, were reclassified to offset long-term debt on the December 31, 2014 balance sheet. We also early implemented ASU 2015-17, Balance Sheet Classification of Deferred Taxes, during the fourth quarter of 2015. Since we adopted this ASU on a retrospective basis, we reclassified current deferred income taxes of $52.4 million, previously reported as a separate component of current assets, to offset long-term deferred income tax liabilities on the December 31, 2014 balance sheet.

As a result of the WEC Merger, we adopted the financial statement presentation policies of WEC Energy Group. See Note 2, Merger, for more information. The previously reported items below were reclassified to conform to the current period presentation. Only material reclassifications are quantified below.

Income Statements

- Certain amortizations of regulatory deferrals were reclassified from other operation and maintenance to cost of sales, depreciation and amortization, and other income, net. Other operation and maintenance costs of $3.1 million and $5.6 million for the years ended December 30, 2014, and 2013, respectively, were reclassified to cost of sales.

- Payroll taxes of $29.3 million and $29.9 million for the years ended December 31, 2014, and 2013 respectively, were reclassified from taxes other than income taxes to other operation and maintenance. The taxes other than income taxes line item was also renamed to property and revenue taxes.

- Certain expenses in cost of sales were reclassified to operating revenues, other operation and maintenance, and depreciation and amortization. The amounts reclassified to other operation and maintenance were $5.9 million and $6.7 million for the years ended December 30, 2014, and 2013, respectively.

- Equity in earnings of transmission affiliate is now shown separately on the income statements. Earnings from our other equity method investments were reclassified to other income, net.

- Noncontrolling interest in subsidiaries was reclassified to other income, net.

Balance Sheet

- Current regulatory assets of $47.2 million and $71.7 million were reclassified to accounts receivable and unbilled revenues and long-term regulatory assets, respectively.

- Equity investment in transmission affiliate is now shown separately on the balance sheets. Our other equity method investments of $13.9 million were reclassified to other long-term assets.

- Current regulatory liabilities of $44.8 million and $108.9 million were reclassified to other current liabilities and long-term regulatory liabilities, respectively.

Statements of Cash Flows

- Various line items within the operating, investing, and financing activities sections were reclassified; however, there was no impact on the total cash flows of these sections.

Statements of Equity

- Noncontrolling interest in subsidiaries was removed from the statements of equity as it was reclassified to other long-term liabilities.

We also reorganized our business segments during the second quarter of 2015. All prior period amounts impacted by this change were reclassified to conform to the new presentation. See Note 26, Segment Information, for more information on our business segments.

The assets associated with PDL's Combined Locks Energy Center were reclassified out of held for sale on our December 31, 2014 balance sheet.

(c) Cash and Cash Equivalents—Cash and cash equivalents include marketable debt securities acquired three months or less from maturity.

(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 and Michigan wholesale electric operations and our Michigan electric retail 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 them to earn a greater return on common equity 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. The natural gas utilities 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 AMRP costs.

Revenues are also impacted by other accounting policies related to PGL's natural gas hub and WPS's participation in the MISO Energy Markets. Amounts collected from PGL's wholesale customers that use the natural gas hub are credited to natural gas costs, resulting in a reduction to retail customers' charges for natural gas and services. 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 revenue. If WPS was a net purchaser in a particular hour, the net amount was recorded as cost of sales on our income statements.

ITF accounts for revenues from construction management projects using the percentage of completion method. Revenues are recognized based on the percentage of costs incurred to date compared to the total estimated costs of each contract. This method is used because management considers total costs to be the best available measure of progress on these contracts. See Note 4, Dispositions, for information related to the sale of ITF on February 29, 2016.

We provide regulated electric service to customers in Wisconsin and Michigan and regulated natural gas service to customers in Wisconsin, Illinois, Minnesota, and Michigan. The geographic concentration of our customers did not contribute significantly to our overall exposure to credit risk. We periodically review customers' credit ratings, financial statements, and historical payment performance and require them to provide collateral or other security as needed. Credit risk exposure at 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, 2015. In addition, there were no customers that accounted for more than 10% of our revenues for the year ended December 31, 2015.

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

(in millions)	2015	2014
Natural gas in storage	**$ 190.9**	$ 196.6
Fossil fuel	**76.3**	49.0
Materials and supplies	**61.0**	82.1
Total	**$ 328.2**	$ 327.7

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 Last-in, First-out (LIFO) cost method. Inventories stated on a LIFO basis represented approximately 39% of total inventories at December 31, 2015, and 37% of total inventories at December 31, 2014. The estimated replacement cost of natural gas in inventory at December 31, 2015, and December 31, 2014, exceeded the LIFO cost by $15.2 million and $47.7 million, respectively. In calculating these replacement amounts, PGL and NSG used a Chicago city-gate natural gas price per Dth of $2.48 at December 31, 2015, and $3.04 at December 31, 2014.

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. These investments are classified as trading securities for accounting purposes. As we do not intend to sell these investments in the near term, they are included in other long-term assets on our balance sheets. The net unrealized gains included in earnings related to the investments held at the end of the period were not significant for the year ended December 31, 2015, and were $1.8 million and $1.9 million for the years ended December 31, 2014, and 2013, 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 revenue 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 8, 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 capitalized interest. Utility property also includes AFUDC – Equity. Additions to and significant replacements of property are charged to property, plant, and equipment at cost; minor items are charged to 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	**2015**	**2014**	**2013**
WPS – Electric	**2.70%**	2.73%	2.79%
WPS – Natural gas	**2.15%**	2.17%	2.19%
PGL	**3.35%**	3.20%	3.19%
NSG	**2.45%**	2.44%	2.44%
MERC [(1)]	**2.50%**	2.49%	1.88%
MGU [(2)]	**2.65%**	2.65%	1.93%

(1) The 2013 depreciation rate reflects the impact of a new depreciation study approved by the MPUC in July 2013. The rates were effective retroactive to January 2012. An approximate $2 million reduction in depreciation expense was recorded in 2013 related to the 2012 impact.

(2) The 2013 depreciation rate includes the impact of a $2.5 million reduction in depreciation expense that was recorded in the first quarter of 2013 as a result of the Michigan Court of Appeals order reversing the MPSC's previously ordered disallowance associated with the early retirement of certain MGU assets in 2010.

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.

We receive grants related to certain renewable generation projects under federal and state grant programs. Our policy is to reduce the depreciable basis of the qualifying project by the grant received. We then reflect the benefit of the grant in income over the life of the related renewable generation project through a reduction in depreciation expense.

See Note 9, 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 stockholders' 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 2015, WPS's average AFUDC retail rate was 7.92%, and its average AFUDC wholesale rate was 5.10%. The AFUDC calculation for WBS uses the WPS AFUDC retail rate, while the other utilities AFUDC rates are determined by their respective state commissions, each with specific requirements. Based on these requirements, the other utilities and WBS did not record significant AFUDC for 2015, 2014, or 2013.

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

	2015	2014	2013
AFUDC – Debt	**$ 7.1**	$ 5.2	$ 4.1
AFUDC – Equity	**17.7**	12.5	10.8

(j) 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. Intangible assets with definite lives are reviewed for impairment on a quarterly basis. Other long-lived assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying value may not be recoverable.

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.

Our reporting units containing goodwill perform annual goodwill impairment tests during the second quarter of each year. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit exceeds the reporting unit's fair value. An impairment loss is recorded for the excess of the carrying amount of the goodwill over its implied fair value. See Note 12, Goodwill and Other Intangible Assets, for more information.

The carrying amount of assets held for sale is not recoverable if the carrying amount exceeds the fair value less estimated costs to sell the asset. An impairment loss is recorded for the excess of the asset’s carrying amount over the fair value less estimated costs to sell.

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.

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

(l) Asset Retirement Obligations—We recognize, at fair value, legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development, and normal operation of the assets. A 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 AROs are accreted to their present value each period using the credit-adjusted risk-free interest rate associated with the expected settlement dates of the AROs. This rate is determined when the obligation is 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 11, Asset Retirement Obligations, for more information.

(m) 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 20, Commitments and Contingencies, for more information.

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

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.

(n) Income Taxes—We filed a consolidated United States income tax return that included domestic subsidiaries of which our ownership is 80% or more for all tax periods up to and including the tax year ended June 29, 2015. For all tax periods after June 29, 2015, we and our subsidiaries are included within the WEC Energy Group consolidated return. Similarly, we and our consolidated subsidiaries were party to a tax allocation arrangement for tax periods up to and including June 29, 2015, and are a party to a tax allocation arrangement with WEC Energy Group and its consolidated subsidiaries for tax periods ending after June 29, 2015.

Deferred income taxes have been recorded to recognize the expected future tax consequences of events that have been included in the financial statements by using currently enacted tax rates for the differences between the income tax basis of assets and liabilities and the basis reported in the financial statements. We record valuation allowances for deferred income tax assets unless it is more likely than not that the benefit will be realized in the future. Our utilities defer certain adjustments made to income taxes that will impact future rates and record regulatory assets or liabilities related to these adjustments.

We use the deferral method of accounting for investment tax credits (ITCs). Under this method, we record the ITCs as deferred credits and amortize such credits as a reduction to the provision for income taxes over the life of the asset that generated the ITCs. ITCs that do not reduce income taxes payable for the current year are eligible for carryover and recognized as a deferred income tax asset.

We report interest and penalties accrued related to income taxes as a component of income tax expense in our income statements.

See Note 17, Income Taxes, for more information regarding accounting for income taxes.

(o) 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 18, Guarantees, for more information.

(p) Employee Benefits—The costs of pension and OPEB plans are expensed over the periods during which employees render service. These costs are allocated among WEC Energy Group's subsidiaries based on current employment status and actuarial calculations, as applicable. Our regulators allow recovery in rates for the utilities' net periodic benefit cost calculated under GAAP. See Note 19, Employee Benefits, for more information.

(q) 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 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, accounts payable, and short-term borrowings, the carrying amount of each such item approximates fair value. The fair value of our long-term debt, including the current portion of 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 our bond rating and the present value of future cash flows.

We conduct a thorough review of fair value hierarchy classifications on a quarterly basis.

See Note 21, Fair Value Measurements, for more information.

(r) 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. Regulated hedging programs are approved by our state regulators.

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

We classify derivative assets and liabilities as current or long-term on our balance sheets based on the maturities of the underlying contracts. Gains and losses on derivative instruments are primarily recorded in cost of sales on the 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 22, Derivative Instruments, for more information.

(s) Subsequent Events—Subsequent events were evaluated for potential recognition or disclosure through March 17, 2016, which is the date the financial statements were available to be issued.

NOTE 2—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 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 Wisconsin Electric filed a joint integrated resource plan with the PSCW for their combined loads, which indicated that there is no need to proceed with the proposed construction of a new generating unit at the Fox Energy Center site at this time. WPS has been authorized to recover the costs it recorded at December 31, 2015 related to the proposed construction.

The ICC order includes a base rate freeze for PGL and NSG effective for two years after the close of the merger. This base rate freeze does not impact PGL's or NSG's ability to adjust rates through various riders or gas cost recovery mechanisms.

We do not believe that the conditions set forth in the various regulatory orders approving the merger will have a material impact on our operations or financial results.

In connection with the merger, we recorded pre-tax merger costs of $86.9 million and $10.4 million during 2015 and 2014, respectively. These 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 payments of $15.7 million were made during 2015, leaving a severance accrual of $2.7 million on our balance sheet at December 31, 2015. Severance costs to be incurred after December 31, 2015 are not expected to be material. The severance expense was recorded in the following segments:

(in millions)	2015
Wisconsin	$ 4.6
Illinois	0.9
Other states	0.1
Corporate and other	12.8
Total severance expense	$ 18.4

NOTE 3—ACQUISITION

In March 2013, WPS acquired all of the equity interests in Fox Energy Company LLC for $391.6 million. Fox Energy Company LLC was dissolved into WPS immediately after the purchase.

The purchase included the Fox Energy Center, a 593-MW combined-cycle electric generating facility located in Wisconsin, along with associated contracts. Fox Energy Center is a dual-fuel facility, equipped to use fuel oil, but being run primarily on natural gas. This plant gives WPS a more balanced mix of owned electric generation, including coal, natural gas, hydroelectric, wind, and other renewable sources. In giving its approval for the purchase, the PSCW stated that the purchase price was reasonable and will benefit ratepayers.

The purchase price was allocated based on the estimated fair values of the assets acquired and the liabilities assumed at the date of acquisition, as follows:

(in millions)	
Assets acquired (1)	
Materials, supplies, and inventories	$ 3.0
Other current assets	0.4
Property, plant, and equipment	374.4
Other long-term assets (2)	15.6
Total assets acquired	$ 393.4
Liabilities assumed	
Accounts payable	$ 1.8
Total liabilities assumed	$ 1.8

(1) Relates to the Wisconsin segment.

(2) Intangible assets recorded for contractual services agreements. See Note 12, Goodwill and Other Intangible Assets, for more information.

Prior to the purchase, WPS supplied natural gas for the facility and purchased 500 MWs of capacity and the associated energy output under a tolling arrangement. WPS paid $50.0 million for the early termination of the tolling arrangement. This amount was recorded as a regulatory asset, as WPS is authorized recovery by the PSCW. The amount is being amortized over a nine-year period that began on January 1, 2014.

WPS's 2015 retail electric rate increase included the recovery of 2013 deferred costs related to the acquisition of the Fox Energy Center. See Note 23, Regulatory Environment, for more information. WPS's rate order effective January 1, 2014, included the costs of owning and operating the Fox Energy Center.

Pro forma adjustments to our revenues and earnings prior to the date of acquisition would not be meaningful or material. Prior to the acquisition, the Fox Energy Center was a nonregulated plant and sold all of its output to third parties, with most of the output purchased by WPS. The plant is now part of WPS's regulated fleet, used to serve its customers.

NOTE 4—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.

On February 29, 2016, we sold ITF, a provider of CNG fueling services and a single-source provider of CNG fueling facility design, construction, operation, and maintenance. The purchase price is subject to adjustments for working capital, and there will be no gain or loss recorded on the sale in the first quarter of 2016, as ITF has already been written down to fair market value, less costs to sell. The sale of ITF met the criteria to qualify as held for sale at December 31, 2015, but did not meet the requirements to qualify as a discontinued operation. 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 will not have a major effect on our operations and financial results. We recognized losses before income taxes of $20.9 million, $0.5 million, and $7.5 million for the years ended December 31, 2015, 2014, and 2013, respectively.

The following table shows the carrying values of the major classes of assets and liabilities included as held for sale on our balance sheet at December 31:

(in millions)	**2015**
Accounts receivable and unbilled revenues	**$ 29.2**
Materials, supplies, and inventories	**18.4**
Other current assets	**1.6**
Property, plant, and equipment	**51.4**
Goodwill	**3.8**
Other long-term assets	**10.7**
Total assets	**$ 115.1**
Accounts payable	**$ 12.6**
Accrued payroll and benefits	**2.4**
Other current liabilities	**5.5**
Deferred income taxes	**6.5**
Deferred investment tax credits	**1.2**
Pension and OPEB obligations	**1.2**
Other long-term liabilities	**0.6**
Total liabilities	**$ 30.0**

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. During the second quarter of 2015, we recorded a pre-tax gain on the sale of $5.2 million, which included transactions costs of $0.9 million. 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 will 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, $3 million, and $3 million for the period ended May 31, 2015, and the years ended December 31, 2014, and 2013, respectively.

The following table shows the carrying values of the major classes of assets and liabilities included in the sale:

(in millions)	As of the Closing Date in June 2015	Held for Sale at December 31, 2014
Cash and cash equivalents	$ 0.3	$ —
Accounts receivable and unbilled revenues	0.7	—
Property, plant, and equipment, net of accumulated depreciation of $22.1 and $21.1, respectively	31.1	32.1
Other long-term assets	17.9	19.4
Total assets	**$ 50.0**	$ 51.5
Current liabilities	$ 0.3	$ 0.3
Deferred investment tax credits	4.6	5.0
Asset retirement obligations	1.1	1.1
Other long-term liabilities	6.8	7.4
Total liabilities	**$ 12.8**	$ 13.8

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

In November 2012, Sunbury Holdings, LLC, 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 the fourth quarter of 2015, we evaluated the collectibility 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 Compressed Natural Gas Fueling Stations

In November 2014, ITF sold eight CNG fueling stations to AMP Trillium LLC, a joint venture between ITF and AMP Americas LLC. At the time of sale, ITF owned 30% and AMP Americas LLC owned 70% of AMP Trillium LLC. The fair value of the CNG fueling stations was $13.0 million. ITF received cash proceeds of $7.2 million, a $2.7 million note receivable from the buyer with a seven-year term, and a $3.1 million equity interest in the joint venture to maintain its ownership interest. In November 2014, we recorded a pre-tax gain of $1.8 million ($1.1 million after-tax) related to the sale of the CNG fueling stations and deferred a gain of $0.8 million that is being recognized over the lives of the stations sold. The pre-tax gain was reported as a component of other operation and maintenance on the income statements. The results of operations of the CNG fueling stations 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.

Net property, plant, and equipment of $10.4 million was included with the sale on November 1, 2014, which is net of accumulated depreciation of $0.7 million.

Other States Segment – Sale of UPPCO

In August 2014, we sold all of the stock of UPPCO to Balfour Beatty Infrastructure Partners LP for $336.5 million, which was net of cash divested of $0.2 million. In the third quarter of 2014, we recorded a pre-tax gain of $85.4 million ($51.2 million after-tax) related to the sale of UPPCO, which was net of transaction costs of $1.1 million. Following the sale, we are providing certain administrative and operational services to UPPCO during a transition period of 18 to 30 months. UPPCO met the criteria in the accounting guidance to qualify as held for sale but did not meet the requirements to qualify as a discontinued operation. The results of operations of UPPCO remained in continuing operations through the sale date due to WPS having significant continuing cash flows with UPPCO that continued after the sale related to certain power purchase transactions.

The following table shows the carrying values of the major classes of assets and liabilities related to UPPCO included in the sale:

(in millions)	As of the Closing Date in August 2014
Current assets	$ 24.3
Property, plant, and equipment, net of accumulated depreciation of $91.3	194.4
Other long-term assets	72.8
Total assets	$ 291.5
Current liabilities	$ 12.7
Long-term liabilities	28.6
Total liabilities	$ 41.3

Corporate and Other Segment – Winnebago Energy Center

In May 2014, a fire significantly damaged the Winnebago Energy Center, a landfill-gas-to-electric facility that was owned by PDL. In the third quarter of 2014, we decided to abandon the facility and received proceeds of $6.1 million for both insurance recovery for the damage caused by the fire and from the sale of miscellaneous parts. As a result, we recorded a pre-tax gain of $5.0 million ($3.0 million after-tax). The results of operations of the Winnebago Energy Center 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.

Discontinued Operations

See Note 7, Supplemental Cash Flow Information, for cash flow information related to discontinued operations.

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 (Exelon) for $325.6 million, which was net of cash divested of $7.6 million. We recorded a pre-tax loss on the sale of $28.8 million ($17.3 million after tax), which included transaction costs of $4.5 million in 2014. Included in these costs was an immaterial amount related to severances.

The retail energy business consisted of mostly financial assets and liabilities; therefore, it did not qualify as held for sale under the applicable accounting guidance. The sale of the retail energy business was the result of a previously announced shift in our corporate strategy to focus on our 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 carrying values of the major classes of assets and liabilities included in the sale:

(in millions)		As of the Closing Date in November 2014
Cash and cash equivalents	$	7.6
Accounts receivable and unbilled revenues, net of reserves of $1.8		293.8
Materials, supplies, and inventories		52.4
Current derivative assets		234.8
Other current assets		75.1
Property, plant, and equipment, net of accumulated depreciation of $16.6		4.5
Long-term derivative assets		106.9
Other long-term assets		25.5
Total assets	$	800.6
Accounts payable	$	186.9
Current derivative liabilities		169.7
Accrued taxes		0.2
Other current liabilities		6.7
Long-term derivative liabilities		79.5
Other long-term liabilities		0.3
Total liabilities	$	443.3

Included in the sale were commodity contracts that did not meet the GAAP definition of derivative instruments and, therefore, were not reflected on the balance sheets. In accordance with GAAP, expected gains or losses related to nonderivative commodity contracts are not recognized until the contracts are settled.

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

(in millions)		2015		2014		2013
Operating revenues	**$**	**—**	$	2,587.1	$	2,150.9
Cost of sales		**—**		(2,444.7)		(1,910.7)
Other operation and maintenance		**(1.2)**		(91.5)		(105.6)
Depreciation and amortization		**—**		(2.7)		(3.2)
Property and revenue taxes		**(0.2)**		(4.9)		(3.2)
Goodwill impairment loss		**—**		(6.7)		—
Loss on sale of IES retail energy business		**—**		(28.8)		—
Other income, net		**0.1**		0.6		7.9
Interest expense		**—**		(0.7)		(0.8)
Income before taxes		**(1.3)**		7.7		135.3
Income tax expense (benefit)		**0.5**		(7.3) *		(52.8)
Discontinued operations, net of tax	**$**	**(0.8)**	$	0.4	$	82.5

* See Note 17, Income Taxes, for more information.

The June 2014 announcement of the potential sale triggered an interim goodwill impairment test. Based on the results of the interim goodwill impairment analysis, IES recorded a non-cash goodwill impairment loss in the second quarter of 2014. This goodwill impairment loss reflected the offers received for IES's retail energy business.

Corporate and Other Segment – Sale of WPS Beaver Falls Generation, LLC (Beaver Falls) and WPS Syracuse Generation, LLC (Syracuse)

In March 2013, WPS Empire State, Inc. sold all of the membership interests of Beaver Falls and Syracuse, both of which owned natural gas-fired generation plants located in the state of New York. The sale agreement included a potential annual payment to us for a four-year period following the sale based on a certain level of earnings achieved by the buyer (an earn-out). In September 2014, we entered into an agreement to receive $2.0 million in settlement of this earn-out agreement, which is presented in other operation and maintenance in the table below.

The following table shows the components of discontinued operations related to Beaver Falls and Syracuse recorded on the income statements:

(in millions)	2014	2013
Operating revenues	$ —	$ 1.2
Cost of sales	—	(0.9)
Other operation and maintenance	2.0	0.4 *
Property and revenue taxes	—	(0.3)
Income before taxes	2.0	0.4
Income tax expense	(0.8)	(0.2)
Discontinued operations, net of tax	$ 1.2	$ 0.2

* Includes a $1.0 million gain on sale at closing.

Corporate and Other Segment – Uncertain Tax Positions

In 2014, we recorded a $0.7 million after-tax gain at the holding company and other segment when we remeasured an uncertain tax position included in our liability for unrecognized tax benefits due to a lapse in the statute of limitations. In 2013, we recorded a $5.9 million after-tax gain in discontinued operations when we remeasured uncertain tax positions included in our liability for unrecognized tax benefits after effectively settling certain state income tax examinations. We reduced income tax expense related to these remeasurements.

NOTE 5—RELATED PARTIES

We and our subsidiaries routinely enter into transactions with related parties, including WEC Energy Group, Wisconsin Electric, Wisconsin Gas LLC, and entities in which we have material interests. The following agreements result in related party receivables and payables.

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 affiliated interest agreement (Non-WBS AIA) went into effect. The new Non-WBS AIA includes WEC Energy Group and the legacy Wisconsin Energy Corporation subsidiaries. It governs the provision and receipt of services by WEC Energy Group's subsidiaries, except that WBS will continue to provide services to us and our subsidiaries only under the existing WBS affiliated interest agreements (WBS AIAs). WBS will provide services to WEC Energy Group and the legacy Wisconsin Energy Corporation subsidiaries under new interim WBS affiliated interest agreements (interim WBS AIAs). The Non-WBS AIA includes no other significant changes from the prior Non-IBS affiliated interest agreement. The PSCW and all other relevant state commissions have approved the Non-WBS AIA or granted appropriate waivers related to the Non-WBS AIA.

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

WBS provides several categories of services (including financial, human resources, and administrative services) to us and our subsidiaries pursuant to the WBS AIAs, which have been approved, or from which we have been granted appropriate waivers, by the appropriate regulators. As required by FERC regulations for centralized service companies, WBS renders services at cost. The appropriate regulators 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 regulatory approval. Recovery of allocated costs is addressed in our rate cases.

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.

We provide services to WRPC under an operating agreement approved by the PSCW. We are also party to a service agreement with WRPC under which either party may be a service provider. Services are billed to and from WRPC under these agreements at a fully allocated cost.

See Note 6, Equity Method Investments, for more information on our transactions with equity method investees.

During the year ended December 31, 2015, WPS sold $0.1 million and $0.4 million of electricity and natural gas, respectively, to Wisconsin Electric. We had no material related party transactions other than our transactions with equity method investees described above during the years ended December 31, 2014 and 2013.

We manage our liquidity in part by maintaining adequate financing commitments with related parties. We have the ability to borrow up to $400.0 million from our parent, WEC Energy Group. At December 31, 2015, our short-term note payable balance with WEC Energy Group was $95.1 million.

NOTE 6—EQUITY METHOD INVESTMENTS

Investments in corporate joint ventures and other companies accounted for under the equity method at December 31, 2015 and 2014 were as follows:

(in millions)	2015	2014
ATC	**$ 550.4**	$ 536.7
INDU Solar Holdings, LLC	**—**	21.8
WRPC	**8.4**	7.7
Other	**1.4**	6.2
Equity method investments	**$ 560.2**	$ 572.4

American Transmission Company

Our electric transmission segment consists of WPS Investments, LLC's ownership interest in ATC, which was approximately 34% at December 31, 2015. ATC is a for-profit, transmission-only company regulated by FERC. We have one representative on ATC's ten-member board of directors. Each member of the board has only one vote. Due to voting requirements, no individual board member has more than 10% of the voting control.

The following table shows changes to our investment in ATC during the years ended December 31:

(in millions)	2015	2014	2013
Balance at beginning of period	**$ 536.7**	$ 508.4	$ 476.6
Add: Earnings from equity method investment	**70.6**	85.7	89.1
Add: Capital contributions	**6.8**	17.0	13.7
Less: Distributions received	**63.7**	74.4	71.0
Balance at end of period	**$ 550.4**	$ 536.7	$ 508.4

We pay ATC for transmission and other related services it provides. In addition, we provide a variety of operational, maintenance, and project management work for ATC, which is reimbursed to us 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)	2015	2014	2013
Charges to ATC for services and construction	**$ 10.3**	$ 9.9	$ 11.3
Charges from ATC for network transmission services	**101.3**	103.8	104.9

As of December 31, 2015 and 2014, our balance sheets included the following receivables and payables related to ATC:

(in millions)	2015	2014
Accounts receivable		
Services provided to ATC	**$ 0.5**	$ 0.9
Accounts payable		
Network transmission services from ATC	**8.5**	8.2

INDU Solar Holdings, LLC

In June 2015, our interest in INDU Solar Holdings, LLC was sold to TerraForm Power, Inc. See Note 4, Dispositions, for more information on this sale. Integrys Solar, LLC, a subsidiary of PDL, owned 50% of INDU Solar Holdings, LLC. INDU Solar Holdings, LLC owned solar energy projects in California, Pennsylvania, New Jersey, Arizona, and Massachusetts that delivered electricity and related products to commercial, government, and utility customers under long-term power purchase agreements. The following table shows changes to our investment in INDU Solar Holdings, LLC during the years ended December 31:

(in millions)	2015	2014	2013
Balance at the beginning of period	**$ 21.8**	$ 24.7	$ 27.5
Add: Earnings from equity method investment	**0.7**	1.8	1.3
Less: Return of capital to partners	**1.0**	4.7	4.1
Less: Sale of INDU Solar Holdings, LLC	**21.5**	—	—
Balance at the end of period	**$ —**	$ 21.8	$ 24.7

Wisconsin River Power Company

WPS owns 50% of the stock of WRPC, which owns two hydroelectric plants and an oil-fired combustion turbine. Half of the energy output of the hydroelectric plants is sold to WPS, and half is sold to Wisconsin Power and Light Company, an unaffiliated public utility. The electric power from the combustion turbine is also sold in equal parts to WPS and Wisconsin Power and Light Company.

The following table shows changes to our investment in WRPC during the years ended December 31:

(in millions)	2015	2014	2013
Balance at beginning of period	**$ 7.7**	$ 7.0	$ 7.3
Add: Earnings from equity method investment	**0.7**	0.8	1.0
Add: Capital contributions	**—**	0.5	—
Less: Distributions received	**—**	0.6	1.3
Balance at end of period	**$ 8.4**	$ 7.7	$ 7.0

WPS provides services to WRPC and purchases energy from WRPC. The following table summarizes WPS's significant related party transactions with WRPC during the years ended December 31:

(in millions)	2015	2014	2013
Charges to WRPC for operations	**$ 1.1**	$ 1.4	$ 0.9
Purchases of energy from WRPC	**3.8**	3.7	3.7

Financial Data

Combined financial data of our significant equity method investments, ATC, INDU Solar Holdings, LLC, and WRPC, is included in the tables below:

(in millions)	2015	2014	2013
Income statement data			
Operating revenues	**$ 627.7**	$ 652.0	$ 642.0
Operating expenses	**325.6**	318.7	306.2
Other expense	**98.7**	89.4	83.7
Net income	**$ 203.4**	$ 243.9	$ 252.1
Earnings from equity method investments	**$ 72.0**	$ 88.3	$ 91.4

(in millions)	December 31, 2015	December 31, 2014
Balance sheet data		
Current assets	**$ 87.3**	$ 73.1
Long-term assets	**3,976.9**	3,803.8
Total assets	**$ 4,064.2**	$ 3,876.9
Current liabilities	**$ 332.0**	$ 314.9
Long-term debt	**1,800.0**	1,709.8
Other long-term liabilities	**252.5**	172.9
Shareholders' equity	**1,679.7**	1,679.3
Total liabilities and shareholders' equity	**$ 4,064.2**	$ 3,876.9

NOTE 7—SUPPLEMENTAL CASH FLOW INFORMATION

(in millions)	2015	2014	2013
Cash paid for interest, net of amount capitalized	**$ 150.0**	$ 146.8	$ 116.1
Cash (received) paid for income taxes, net of refunds	**(42.5)**	6.3	(4.8)
Significant non-cash transactions:			
Construction costs funded through accounts payable	**165.4**	180.5	108.5
Note receivable received related to the sale of AMP Trillium*	**12.0**	—	—
Capital assets received related to the sale of AMP Trillium*	**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**	—	—
Accounts receivable converted to notes receivable related to sales of ITF fueling stations constructed on behalf of others	**—**	10.9	—
Portion of ITF fueling station sale financed with note receivable *	**—**	2.7	—
Equity interest in joint venture received for a portion of the ITF fueling station sale *	**—**	3.1	—
Equity issued for employee stock ownership plan	**—**	1.7	14.3
Equity issued for stock-based compensation plans	**—**	—	16.3
Equity issued for reinvested dividends	**—**	—	12.0

* See Note 4, Dispositions, for more information.

At December 31, 2015, restricted cash of $118.4 million was recorded within other long-term assets on our balance sheet. The majority of this amount was held in the rabbi trust and was a portion of the required funding for the rabbi trust that was triggered by the announcement of the WEC Merger. See Note 2, Merger, for more information about the WEC Merger. See Note 19, Employee Benefits, for more information on the rabbi trust funding requirements.

Discontinued Operations

Significant noncash transactions and other information related to discontinued operations are disclosed below.

(in millions)	2015	2014	2013
Operating activities			
Depreciation and amortization expense	$ —	$ 2.7	$ 3.3
Net unrealized gains on energy contracts	—	(22.7)	(100.3)
Deferred income taxes and investment tax credits	—	36.1	56.1
Remeasurement of uncertain tax positions included in our liability for unrecognized tax benefits	—	(0.7)	(5.9)
Loss on sale of IES's retail energy business *	—	24.3	—
Other	—	33.4	23.8
Investing activities			
Capital expenditures	—	(0.8)	(2.6)
Contingent consideration and payables related to the acquisition of Compass Energy Services	—	—	7.8

* See Note 4, Dispositions, for more information.

NOTE 8—REGULATORY ASSETS AND LIABILITIES

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

(in millions)	2015	2014	See Note
Regulatory assets (1) (2)			
Environmental remediation costs (3)	**$ 654.0**	$ 635.8	20
Unrecognized pension and OPEB costs (4)	**588.2**	599.7	19
AROs	**136.7**	109.4	11
Income tax related items (5)	**63.8**	60.6	
Derivatives	**40.4**	55.2	1(r)
Termination of a tolling agreement with Fox Energy Company LLC	**39.1**	44.6	3
Crane Creek production tax credits (6)	**30.9**	32.2	
Uncollectible expense (7)	**23.1**	13.6	1(d)
Energy costs recoverable through rate adjustments (8)	**20.9**	22.2	
De Pere Energy Center (9)	**19.0**	21.4	
Unamortized loss on reacquired debt (10)	**15.7**	16.6	
Other	**46.9**	21.2	
Total regulatory assets	**$ 1,678.7**	$ 1,632.5	
Balance Sheet Presentation			
Current assets (11)	**$ 37.1**	$ 47.2	
Regulatory assets	**1,641.6**	1,585.3	
Total regulatory assets	**$ 1,678.7**	$ 1,632.5	

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

(2) As of December 31, 2015, we had $21.0 million of regulatory assets not earning a return.

(3) As of December 31, 2015, we had not yet made cash expenditures for $598.2 million of these environmental remediation costs. The recovery of these costs depends on the timing of the actual expenditures.

(4) Represents the unrecognized future pension and OPEB costs resulting from actuarial gains and losses on defined benefit and OPEB plans.

(5) Adjustments related to deferred income taxes. As the related temporary differences reverse, we prospectively collect taxes from customers for which deferred taxes were recorded in prior years.

(6) 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.

(7) Represents amounts recoverable from customers related to uncollectible true-up mechanisms at NSG and PGL. These mechanisms allow NSG and PGL to recover or refund the difference between actual uncollectible write-offs and the amounts recovered in rates.

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

(9) 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.

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

(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)	**2015**	**2014**	**See Note**
Regulatory liabilities			
Removal costs [1]	**$ 350.1**	$ 334.0	
Energy costs refundable through rate adjustments [2]	**59.6**	44.8	
Unrecognized pension and OPEB costs [3]	**26.3**	45.2	19
Uncollectible expense	**11.5**	15.7	1(d)
Energy efficiency programs [4]	**11.2**	21.3	
Derivatives	**8.7**	19.8	1(r)
Decoupling	**8.3**	49.4	23
Crane Creek depreciation deferral [5]	**8.3**	8.7	
Other	**9.3**	14.7	
Total regulatory liabilities	**$ 493.3**	$ 553.6	
Balance sheet presentation			
Other current liabilities	**$ 33.8**	$ 44.8	
Regulatory liabilities	**459.5**	508.8	
Total regulatory liabilities	**$ 493.3**	$ 553.6	

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

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

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

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

(5) Represents the book depreciation taken on the Crane Creek wind project prior to WPS's election to claim a Section 1603 Grant for the project in lieu of the production tax credit. See more information in the regulatory assets section above.

NOTE 9—PROPERTY, PLANT, AND EQUIPMENT

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

(in millions)	2015	2014
Electric utility	**$ 3,722.8**	$ 3,587.4
Natural gas utility	**6,184.0**	5,811.8
Total utility property, plant, and equipment	**9,906.8**	9,399.2
Less: Accumulated depreciation	**3,216.7**	3,185.9
Net	**6,690.1**	6,213.3
CWIP	**485.9**	351.8
Plant to be retired, net [1]	**—**	12.5
Net utility property, plant, and equipment	**7,176.0**	6,577.6
Non-utility plant and other property, plant, and equipment	**186.2**	265.5
Less: Accumulated depreciation	**51.2**	99.5
Net [2]	**135.0**	166.0
CWIP	**107.6**	84.3
Net non-utility and other property, plant, and equipment	**242.6**	250.3
Total property, plant, and equipment	**$ 7,418.6**	$ 6,827.9

(1) In connection with the WPS Consent Decree with the EPA, WPS retired Weston 1 and Pulliam Units 5 and 6 on June 1, 2015. See Note 20, Commitments and Contingencies, for more information regarding the Consent Decree.

(2) In 2015, impairments were recorded to net non-utility plant and other property, plant, and equipment of $12.1 million. These impairment losses are included in impairment losses on our income statements.

We evaluate property, plant, and equipment for impairment whenever indicators of impairment exist.

NOTE 10—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. The amounts were as follows at December 31, 2015:

(in millions, except for percentages and MWs)	Weston 4	Columbia Energy Center Units 1 and 2	Edgewater Unit 4
Ownership	**70.0%**	**31.8%**	**31.8%**
WPS's share of rated capacity (MWs)*	**374.5**	**352.9**	**96.3**
In-service date	**2008**	**1975 and 1978**	**1969**
Property, plant, and equipment	**$ 591.5**	**$ 404.6**	**$ 47.6**
Accumulated depreciation	**$ (150.5)**	**$ (122.6)**	**$ (30.6)**
CWIP	**$ 5.9**	**$ 23.4**	**$ 0.4**

* Based on expected capacity ratings for summer 2016. 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.

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. See Note 20, Commitments and Contingencies, for more information related to the requirement to refuel, repower, or retire Edgewater Unit 4.

NOTE 11—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. The utilities establish regulatory assets and liabilities to record the differences between ongoing expense recognition under the ARO accounting rules and the rate-making practices for retirement costs authorized by the applicable regulators. PDL has AROs recorded for the removal of solar equipment components.

The following table shows changes to our AROs:

(in millions)	2015	2014	2013
Balance as of January 1	**$ 479.1**	$ 489.9	$ 409.6
Accretion	**23.9**	24.6	20.8
Additions and revisions to estimated cash flows	**19.6** (1)	(17.6) (2)	70.6 (2)
Liabilities settled	**(13.4)**	(17.8)	(11.1)
Balance as of December 31	**$ 509.2**	$ 479.1	$ 489.9

(1) 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. See Note 20, Commitments and Contingencies, for more information on this rule. 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 due to changes in estimated removal costs and settlement dates.

(2) We revised the AROs recorded for our natural gas distribution pipes at PGL primarily due to changes in the weighted average cost to retire pipe.

NOTE 12—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 changes to our goodwill balances by segment during the years ended December 31, 2015 and 2014:

	Wisconsin		Illinois		Other States		Corporate and Other		Total	
(in millions)	2015	2014	2015	2014	2015	2014	2015	2014	2015	2014
Balance as of January 1										
Gross goodwill	**$ 36.4**	$ 36.4	**$ 630.1**	$ 630.1	**$ 267.0**	$ 267.0	**$ 19.6**	$ 19.6	**$ 953.1**	$ 953.1
Accumulated impairment losses	**—**	—	**(192.8)**	(192.8)	**(104.9)**	(104.9)	**—**	—	**(297.7)**	(297.7)
Net goodwill as of January 1	**36.4**	36.4	**437.3**	437.3	**162.1**	162.1	**19.6**	19.6	**655.4**	655.4
ITF goodwill reclassified to held for sale *	**—**	—	**—**	—	**—**	—	**(19.6)**	—	**(19.6)**	—
Balance as of December 31										
Gross goodwill	**36.4**	36.4	**630.1**	630.1	**267.0**	267.0	**—**	19.6	**933.5**	953.1
Accumulated impairment losses	**—**	—	**(192.8)**	(192.8)	**(104.9)**	(104.9)	**—**	—	**(297.7)**	(297.7)
Net goodwill as of December 31	**$ 36.4**	$ 36.4	**$ 437.3**	$ 437.3	**$ 162.1**	$ 162.1	**$ —**	$ 19.6	**$ 635.8**	$ 655.4

* 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 4, Dispositions, for more information.

In the second quarter of 2015, annual impairment tests were completed at all of our reporting units that carried a goodwill balance as of April 1, 2015. No impairments resulted from these tests.

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

	December 31, 2015			December 31, 2014		
(in millions)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized intangible assets (1) (2)	**$ 16.0**	**$ (7.8)**	**$ 8.2**	$ 34.9	$ (11.9)	$ 23.0
Unamortized intangible assets (3)	**5.7**	**—**	**5.7**	10.2	—	10.2
Total intangible assets	**$ 21.7**	**$ (7.8)**	**$ 13.9**	$ 45.1	$ (11.9)	$ 33.2

(1) Primarily relates to 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, 2015, was approximately three years.

(2) 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.

(3) Consists primarily of trade names.

NOTE 13—COMMON EQUITY

On June 29, 2015, all of our outstanding common shares were acquired by WEC Energy Group.

Stock-Based Compensation

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 the deferred compensation plan. The additional expense associated with the accelerated vesting of these awards totaled $22.7 million and is included with merger costs on the income statement. See Note 2, Merger, for more information regarding the merger.

The intrinsic value of the awards settled due to the merger were $26.0 million and $34.8 million for performance stock rights and restricted stock units, respectively. The intrinsic value of stock options settled was not significant. The actual tax benefit realized for the tax deductions from the settled awards was $10.0 million and $12.3 million for performance stock rights and restricted stock units, respectively.

The following table reflects the stock-based compensation expense and the related deferred income tax benefit recognized in income (excluding the expense and related tax benefit associated with the accelerated vesting discussed above) for the years ended December 31:

(in millions)	2015	2014	2013
Stock options	**$ —**	$ 2.7	$ 1.8
Performance stock rights	**3.3**	16.8	2.7
Restricted share units	**8.2**	9.9	8.6
Nonemployee director deferred stock units	**0.9**	0.8	0.9
Total stock-based compensation expense	**$ 12.4**	$ 30.2	$ 14.0
Deferred income tax benefit	**$ 5.0**	$ 12.1	$ 5.6

A summary of the activity for our stock-based compensation awards for the year ended December 31, 2015, is presented below:

	Stock Options	Performance Stock Rights	Restricted Stock Units
Outstanding as of January 1, 2015	**134,017**	**238,571**	**427,305**
Granted	**—**	**—**	**224,784**
Dividend equivalents	**N/A**	**N/A**	**9,154**
Exercised (1)/Distributed (2)/Vested and Released (3)	**(70,692)**	**(40,385)**	**(166,681)**
Forfeited	**—**	**—**	**(948)**
Settled due to WEC Merger	**(63,325)**	**(367,565)**	**(493,614)**
Adjustment for performance stock rights distributed or settled	**N/A**	**169,379**	**N/A**
Outstanding as of December 31, 2015	**—**	**—**	**—**

(1) The intrinsic value of stock options exercised was not significant.

(2) The intrinsic value of shares distributed for performance stock rights was $3.1 million. The actual tax benefit realized for the tax deductions from the distribution of performance stock rights was not significant.

(3) The intrinsic value of restricted share unit awards vested and released was $12.8 million. The actual tax benefit realized for the tax deductions from the vesting and release of restricted share units was $5.1 million.

Restrictions

Our ability to pay dividends or return capital to WEC Energy Group is largely dependent upon the availability of funds from our subsidiaries. Various laws, regulations, and financial covenants impose restrictions on the ability of certain of our regulated utility subsidiaries to transfer funds to us in the form of dividends. 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.

See Note 15, 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, 2015, total restricted net assets of consolidated subsidiaries were $2,016.5 million. Our equity in undistributed earnings of 50% or less owned investees accounted for by the equity method was $162.2 million at December 31, 2015.

We also have long-term debt obligations that contain financial and other covenants, including but not limited to, a requirement to maintain a debt to total capitalization ratio not to exceed 65%.

We have the option to defer interest payments on our outstanding 2006 6.11% Junior Subordinated Notes and our 2013 6.00% 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.

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

NOTE 14—PREFERRED STOCK

The following table shows our subsidiaries' authorized shares of preferred stock and the outstanding shares owned by third parties at December 31, 2015 and 2014:

2015	Shares Authorized	Shares Outstanding	Redemption Price Per Share	Total
WPS				
$100 par value, Preferred Stock	**1,000,000**	—	**N/A**	**N/A**
PGL				
$100 par value, Cumulative Preferred Stock	**430,000**	—	**N/A**	**N/A**
NSG				
$100 par value, Cumulative Preferred Stock	**160,000**	—	**N/A**	**N/A**

2014 *(in millions, except share and per share amounts)*	Shares Authorized	Shares Outstanding	Redemption Price Per Share	Total
WPS				
$100 par value, Preferred Stock	1,000,000			
5.00% Series		130,692	$ 107.50	$ 13.1
5.04% Series		29,898	102.81	3.0
5.08% Series		49,905	101.00	5.0
6.76% Series		150,000	103.35	15.0
6.88% Series		150,000	100.00	15.0
PGL				
$100 par value, Cumulative Preferred Stock	430,000	—	N/A	N/A
NSG				
$100 par value, Cumulative Preferred Stock	160,000	—	N/A	N/A
Total				$ 51.1

On November 13, 2015, WPS redeemed all 511,882 outstanding shares of its five series of preferred stock: (i) 131,916 shares of 5.00% Series; (ii) 29,983 shares of 5.04% Series; (iii) 49,983 shares of 5.08% Series; (iv) 150,000 shares of 6.76% Series; and, (v) 150,000 shares of 6.88% Series. The aggregate redemption price was $52.7 million, plus accumulated and unpaid dividends.

NOTE 15—SHORT-TERM DEBT AND LINES OF CREDIT

Short-term notes payable balances and their corresponding weighted-average interest rates as of December 31 consist of:

(in millions, except percentages)	2015	2014
Commercial paper		
Amount outstanding at December 31	**$ 305.5**	$ 317.6
Average interest rate on amount outstanding at December 31	**0.66%**	0.36%
Average amount outstanding during the year *	**$ 295.8**	$ 283.0
Short-term notes payable to WEC Energy Group		
Average amount outstanding during the year *	**$ 4.2**	$ —
Average interest rate on amount outstanding at December 31	**0.81%**	—%

* Based on daily outstanding balances during the year.

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%.

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	2015
Revolving credit facility (WPS) [1]	December 2016	**250.0**
Revolving credit facility (PGL)	December 2020	**350.0**
Revolving short-term notes payable to WEC Energy Group [2]		**400.0**
Total short-term credit capacity		**$ 1,000.0**
Less:		
Commercial paper outstanding		**$ 305.5**
Short-term notes payable to WEC Energy Group [2]		**95.1**
Available capacity under existing credit agreements		**$ 599.4**

(1) WPS requested approval from the PSCW to extend the maturity through December 2020.

[2] In December 2015, we terminated our prior credit facilities and replaced them with a $400.0 million revolving line of credit from WEC Energy Group.

In December 2015, Integrys, WPS, and PGL terminated their prior credit facilities. At the same time, WPS and PGL entered into new credit facilities. The lenders under the WPS facility have agreed that its maturity can be extended to December 2020, subject to the receipt of PSCW approval. Each of these facilities has a renewal provision for two one-year extensions, subject to lender approval.

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

NOTE 16—LONG-TERM DEBT

At December 31 *(in millions)*					2015	2014
WPS First Mortgage Bonds [1]						
		Interest Rate	Year Due			
		7.125%	2023		**$ —**	$ 0.1
WPS Notes (unsecured) [1]						
		Interest Rate	Year Due			
		6.375%	2015		**—**	125.0
		5.65%	2017		**125.0**	125.0
		1.65%	2018		**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) [2]						
	Series	Interest Rate	Year Due			
	XX	2.21%	2016		**50.0**	50.0
	TT	8.00%	2018		**5.0**	5.0
	UU	4.63%	2019		**75.0**	75.0
	VV	3.90%	2030		**50.0**	50.0
	WW	1.875%	2033	Mandatory interest reset date on August 1, 2020	**50.0**	50.0
	ZZ	4.00%	2033		**50.0**	50.0
	RR	4.30%	2035	Mandatory interest reset date on June 1, 2016	**50.0**	50.0
	YY	3.98%	2042		**100.0**	100.0
	AAA	3.96%	2043		**220.0**	220.0
	BBB	4.21%	2044		**200.0**	200.0
NSG First Mortgage Bonds (secured) [3]						
	Series	Interest Rate	Year Due			
	P	3.43%	2027		**28.0**	28.0
	Q	3.96%	2043		**54.0**	54.0
Integrys Senior Notes (unsecured) [4]						
		Interest Rate	Year Due			
		8.00%	2016		**50.0**	55.0
		4.17%	2020		**250.0**	250.0
Integrys Junior Notes (unsecured)						
		Interest Rate	Year Due			
		6.11%	2066	Interest to become variable in December 2016	**269.8**	269.8
		6.00%	2073	Interest to become variable in August 2023	**400.0**	400.0
Total bonds and notes					**3,201.8**	3,081.9
Unamortized debt issuance costs					**(31.1)**	(31.6)
Unamortized discount, net and other					**(0.8)**	(0.6)
Total					**3,169.9**	3,049.7
Less current portion of long-term debt					**100.0**	125.0
Total long-term debt					**$ 3,069.9**	$ 2,924.7

[1] In November 2015, WPS redeemed all of the remaining $0.1 million aggregate principal amount of First Mortgage Bonds, 7.125% Series due July 1, 2023 at a redemption price equal to 100% of the principal amount plus accrued and unpaid interest to the date of redemption. Following the redemption, WPS discharged its mortgage indenture and does not intend to issue additional first mortgage bonds. All of WPS's senior notes outstanding are now senior unsecured obligations and rank equally with all of its other unsecured obligations.

In December 2015, WPS's $125.0 million of 6.375% Senior Notes matured, and the outstanding principal balance was repaid.

In December 2015, WPS issued $250.0 million of 1.65% Senior Notes due December 4, 2018. The proceeds were used to repay short-term debt incurred to repay all of WPS's $125.0 million of 6.375% Senior Notes at maturity, and for working capital and general corporate purposes.

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

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

In August 2015, the interest rate on PGL's $50.0 million of 2.625% Series WW Bonds was reset. The new interest rate is 1.875%. The new mandatory interest reset date is August 1, 2020. The final maturity of these bonds is February 1, 2033.

In November 2016, PGL's 2.21% First and Refunding Mortgage Bonds will mature. As a result, the $50.0 million balance of these bonds was included in the current portion of long-term debt on our balance sheet at December 31, 2015.

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

(4) In July 2015, we tendered an offer to repurchase all $55.0 million outstanding of our 8.00% Senior Notes due June 1, 2016, and $5.0 million of this amount was tendered and purchased. The $50.0 million balance of these notes was included in the current portion of long-term debt on our balance sheet at December 31, 2015.

In connection with our outstanding 2006 6.11% Junior Subordinated Notes (6.11% 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). Integrys's 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 6.11% 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.

In February 2016, we repurchased and retired $154.9 million aggregate principal amount of our 6.11% Junior Notes for a purchase price of $128.6 million, plus accrued and unpaid interest, through a modified "dutch auction" tender offer. Effective December 1, 2016, the remaining $114.9 million aggregate principal amount of the 6.11% Junior Notes will bear interest at the three-month LIBOR rate plus 212 basis points and will reset quarterly.

In connection with the transaction, we issued approximately $66.4 million of additional common stock to WEC Energy Group in satisfaction of our obligations under the Integrys RCC.

Effective August 2023, our $400.0 million of 2013 6.00% Junior Subordinated Notes due 2073 will bear interest at the three-month LIBOR Rate 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. In addition, certain long-term debt obligations contain financial and other covenants, including but not limited to, a requirement to maintain a debt to total capitalization ratio not to exceed 65%. Failure to comply with these covenants could result in an event of default, which could result in the acceleration of outstanding debt obligations.

A schedule of all principal debt payment amounts related to debt maturities is as follows:

(in millions)	**Payments**
2016	$ 100.0
2017	125.0
2018	255.0
2019	75.0
2020	250.0
Thereafter	2,396.8
Total	$ 3,201.8

NOTE 17—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)	2015	2014	2013
Current tax (benefit) expense	**$ (27.9)**	$ 44.1	$ 5.3
Deferred income taxes, net	**161.4**	141.3	144.4
Investment tax credit, net	**(1.5)**	8.0	8.3
Total income tax expense related to continuing operations	**132.0**	193.4	158.0
Total income tax (benefit) expense related to discontinued operations	**(0.5)**	7.2	45.9
Total	**$ 131.5**	$ 200.6	$ 203.9

Statutory Rate Reconciliation

The income tax expense 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:

	2015		2014		2013	
(in millions)	Amount	Effective Tax Rate	Amount	Effective Tax Rate	Amount	Effective Tax Rate
Expected tax at statutory federal tax rates	**$ 106.1**	**35.0 %**	$ 165.0	35.0 %	$ 148.9	35.0 %
State income taxes net of federal tax benefit	**18.1**	**6.0 %**	35.5 *	7.5 % *	15.9	3.7 %
Valuation allowance change	**16.9**	**5.5 %**	(4.9)	(1.0)%	—	—
AFUDC – Equity	**(6.1)**	**(2.0)%**	(3.6)	(0.8)%	(3.4)	(0.8)%
Other, net	**(3.0)**	**(1.0)%**	1.4	0.3 %	(3.4)	(0.8)%
Total income tax expense	**$ 132.0**	**43.5 %**	$ 193.4	41.0 %	$ 158.0	37.1 %

* Includes the impact of a $13.0 million expense caused by the remeasurement of deferred taxes related to the sale of IES's retail energy business.

Deferred Income Tax Assets and Liabilities

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

(in millions)	2015	2014
Deferred income tax assets		
Future tax benefits	**$ 175.7**	$ 165.8
Other	**36.0**	28.3
Total deferred income tax assets	**211.7**	194.1
Valuation allowance	**(17.1)**	(3.6)
Net deferred income tax assets	**$ 194.6**	$ 190.5
Deferred income tax liabilities		
Plant-related	**$ 1,702.1**	$ 1,584.1
Regulatory deferrals	**97.6**	55.6
Employee benefits and compensation	**28.4**	45.4
Other	**37.9**	23.0
Total deferred income tax liabilities	**1,866.0**	1,708.1
Deferred income tax liabilities, net	**$ 1,671.4**	$ 1,517.6
Balance sheet presentation		
Deferred income tax liabilities – included in liabilities held for sale	**$ 6.5**	$ —
Deferred income tax liabilities, net	**1,664.9**	1,517.6
Total deferred income tax liabilities, net	**$ 1,671.4**	$ 1,517.6

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, 2015 and 2014 are summarized in the table below:

2015 ***(in millions)***	**Gross Value**	**Deferred Tax Effect**	**Valuation Allowance**	**Earliest Year of Expiration**
Future tax benefits as of December 31, 2015				
Federal net operating loss	**$ 92.0**	**$ 32.2**	**$ —**	**2031**
Federal foreign tax credit	**—**	**15.2**	**(15.2)**	**2017**
Other federal tax credit	**—**	**113.5**	**—**	**2025**
Charitable contribution	**4.7**	**1.9**	**(1.9)**	**2016**
State net operating loss	**172.3**	**8.6**	**—**	**2024**
State tax credit	**—**	**4.3**	**—**	**2016**
Balance as of December 31, 2015	**$ 269.0**	**$ 175.7**	**$ (17.1)**	

2014 ***(in millions)***	**Gross Value**	**Deferred Tax Effect**	**Valuation Allowance**	**Earliest Year of Expiration**
Future tax benefits as of December 31, 2014				
Federal net operating loss	$ 77.1	$ 27.0	$ —	2032
Federal foreign tax credit	—	6.2	—	2018
Other federal tax credit	—	106.3	—	2026
Charitable contribution	7.4	2.9	—	2017
State net operating loss	357.5	19.2	(3.6)	2025
State tax credit	—	4.2	—	2017
Balance as of December 31, 2014	$ 442.0	$ 165.8	$ (3.6)	

Valuation allowances of approximately $17.1 million have been established for certain tax benefit carryforwards based on our projected ability to realize such benefits by offsetting 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)	**2015**	**2014**
Balance at January 1	**$ 3.3**	$ 3.6
Increase related to tax positions taken in prior years	**0.3**	—
Decrease related to tax positions taken in prior years	**—**	(0.1)
Increase related to tax positions taken in current year	**0.5**	0.5
Decrease related to settlements	**(0.7)**	—
Decrease related to lapse of statutes	**—**	(0.7)
Balance at December 31	**$ 3.4**	$ 3.3

We had accrued interest of $0.1 million and accrued penalties of $0.1 million related to unrecognized tax benefits at December 31, 2015. We had accrued interest of $0.3 million and accrued penalties of $0.2 million related to unrecognized tax benefits at December 31, 2014.

Our effective tax rate could be affected by recognition of $2.2 million of unrecognized tax benefits related to continuing operations in periods after December 31, 2015.

Our subsidiaries file income tax returns in the United States federal jurisdiction and in various state and local jurisdictions as part of our filings up to and including June 29, 2015, and as part of WEC Energy Group's filings after June 29, 2015.

Within the next 12 months, it is reasonably possible that our unrecognized tax benefits may decrease by approximately $3.4 million as the result of information received through a letter ruling request.

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, 2015, we were subject to examination by state or local tax authorities for the 2008 through 2015 tax years in our major state operating jurisdictions as follows:

Jurisdiction	Year
Federal	2012-2015
Illinois	2011-2015
Michigan	2008-2015
Minnesota	2011-2015
Wisconsin	2011-2015

NOTE 18—GUARANTEES

The following table shows our outstanding guarantees:

	Total Amounts Committed	Expiration		
(in millions)	at December 31, 2015	Less Than 1 Year	1 to 3 Years	Over 3 Years
Guarantees supporting commodity transactions of subsidiaries [1]	**$ 174.5**	$ 95.0	$ —	$ 79.5
Standby letters of credit [2]	**10.3**	0.4	9.7	0.2
Surety bonds [3]	**38.0**	38.0	—	—
Other guarantees [4]	**66.9**	20.0	0.1	46.8
Total guarantees	**$ 289.7**	$ 153.4	$ 9.8	$ 126.5

(1) Consists of (a) $5.0 million and $11.0 million to support the business operations of WBS and PDL, respectively; and (b) $117.6 million, $40.3 million, and $0.6 million related to natural gas supply at MERC, MGU, and ITF, respectively. These amounts are not reflected on our balance sheets. We sold ITF on February 29, 2016. See Note 4, Dispositions, for more information.

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

(3) Primarily for the construction and operation of CNG fueling stations by ITF, workers compensation self-insurance programs, and obtaining various licenses, permits, and rights-of-way. These amounts are not reflected on our balance sheets.

(4) Consists of (a) $19.1 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; (b) $20.0 million for an interconnection agreement between WPS and ATC; (c) $10.0 million related to the sale of a nonregulated retail marketing business previously owned by us; (d) $11.2 million related to the performance of an operating and maintenance agreement by ITF; and (e) $6.6 million related to workers compensation coverage. The amounts discussed in items (a), (b) and (d) are not reflected on our balance sheets. An insignificant liability was recorded for item (c) related to the possible imposition of additional miscellaneous gross receipts tax in the event of a change in law or interpretation of the law. In addition, a liability of $6.6 million was recorded for item (e).

NOTE 19—EMPLOYEE BENEFITS

Pension and Other Postretirement Employee Benefits

We and our subsidiaries maintain a noncontributory, qualified pension plan covering the majority of our employees, as well as several unfunded nonqualified retirement plans. In addition, we and our subsidiaries offer multiple OPEB plans to employees. The benefits for a portion of these plans are funded through irrevocable trusts, as allowed for income tax purposes. We also offer medical, dental, and life insurance benefits to active employees and their dependents. We expense the costs of these benefits as incurred.

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) plan, which is calculated based on age, wages, and full years of vesting service as of December 31 each year. In March 2014, we remeasured the obligations of certain OPEB plans as a result of a plan design change to move participants age 65 and older to a Medicare Advantage plan starting January 1, 2015.

In August 2014, we sold UPPCO. The pension and OPEB plan assets and obligations related to UPPCO employees and retirees transferred with the sale and are disclosed in the table below. The impact of this transfer has been reflected in the measurement of the gain on sale of UPPCO. See Note 4, Dispositions, for more information.

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)	**2015**	**2014**	**2015**	**2014**
Change in benefit obligation				
Obligation at January 1	**$ 1,705.7**	$ 1,641.7	**$ 520.0**	$ 576.3
Service cost	**29.4**	24.8	**22.4**	21.0
Interest cost	**67.4**	76.2	**20.8**	23.5
Plan amendments	**—**	—	**—**	(90.4)
Divestitures – UPPCO	**—**	(100.4)	**—**	(22.3)
Actuarial loss (gain)	**(51.1)**	166.1	**(85.6)**	33.1
Participant contributions	**—**	—	**6.6**	10.0
Benefit payments	**(148.9)**	(102.7)	**(25.3)**	(33.3)
Plan curtailment	**0.2**	—	**(0.3)**	—
Federal subsidy on benefits paid	**—**	—	**—**	2.1
Obligation at December 31	**$ 1,602.7**	$ 1,705.7	**$ 458.6**	$ 520.0
Change in fair value of plan assets				
Fair Value at January 1	**$ 1,495.6**	$ 1,527.7	**$ 447.7**	$ 470.1
Actual return on plan assets	**(49.8)**	94.6	**(9.4)**	18.2
Employer contributions	**7.7**	98.8	**8.7**	10.0
Participant contributions	**—**	—	**6.6**	10.0
Divestitures – UPPCO	**—**	(122.8)	**—**	(27.3)
Benefit payments	**(148.9)**	(102.7)	**(25.3)**	(33.3)
Fair value at December 31	**$ 1,304.6**	$ 1,495.6	**$ 428.3**	$ 447.7

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)	**2015**	**2014**	**2015**	**2014**
Other long-term assets	**$ —**	$ —	**$ 8.7**	$ 1.5
Other current liabilities	**—**	9.1	**—**	0.2
Liabilities held for sale	**0.8**	—	**0.4**	—
Pension and OPEB obligations	**297.3**	201.0	**38.6**	73.6
Total net liabilities	**$ 298.1**	$ 210.1	**$ 30.3**	$ 72.3

The accumulated benefit obligation for the defined benefit pension plans was $1,456.8 million and $1,531.1 million at December 31, 2015, and 2014, respectively.

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

(in millions)	**2015**	**2014**
Projected benefit obligation	**$ 1,602.7**	$ 64.1
Accumulated benefit obligation	**1,456.8**	61.2
Fair value of plan assets	**1,304.6**	—

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

	Pension Costs		OPEB Costs	
(in millions)	2015	2014	2015	2014
Accumulated other comprehensive loss (pre-tax) [(1)]				
Net actuarial loss	**$ 44.3**	$ 40.2	**$ (1.3)**	$ 0.2
Prior service credits	**—**	—	**(0.1)**	(0.1)
Total	**$ 44.3**	$ 40.2	**$ (1.4)**	$ 0.1
Net regulatory assets (liabilities) [(2)]				
Net actuarial loss	**$ 596.6**	$ 501.0	**$ 28.0**	$ 50.4
Prior service costs (credits)	**12.2**	1.8	**(74.9)**	(85.3)
Total	**$ 608.8**	$ 502.8	**$ (46.9)**	$ (34.9)

(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 2016:

(in millions)	Pension Costs	OPEB Costs
Net actuarial loss	$ 46.9	$ 4.9
Prior service costs (credits)	1.7	(7.0)
Total 2016 – estimated amortization	$ 48.6	$ (2.1)

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

	Pension Costs			OPEB Costs		
(in millions)	2015	2014	2013	2015	2014	2013
Service cost	**$ 29.4**	$ 24.8	$ 30.2	**$ 22.4**	$ 21.0	$ 24.9
Interest cost	**67.4**	76.2	71.2	**20.8**	23.5	24.8
Expected return on plan assets	**(105.4)**	(112.4)	(105.5)	**(31.7)**	(33.0)	(30.6)
Loss on plan settlement	**1.2**	0.9	—	**—**	—	—
Plan curtailment	**(0.3)**	—	—	**—**	—	—
Amortization of prior service cost (credit)	**2.0**	0.6	4.0	**(10.3)**	(9.4)	(2.5)
Amortization of net actuarial loss	**50.2**	33.3	56.7	**8.9**	3.2	8.4
Net periodic benefit cost	**$ 44.5**	$ 23.4	$ 56.6	**$ 10.1**	$ 5.3	$ 25.0

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

	Pension Costs		OPEB Costs	
	2015	2014	2015	2014
Discount rate	**4.47%**	4.08%	**4.33%**	4.00%
Rate of compensation increase	**4.00%**	4.23%	**N/A**	N/A
Assumed medical cost trend rate	**N/A**	N/A	**7.50%**	6.00%
Ultimate trend rate	**N/A**	N/A	**5.00%**	5.00%
Year ultimate trend rate is reached	**N/A**	N/A	**2021**	2023

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		
	2015	2014	2013
Discount rate	**4.08%**	4.92%	4.07%
Expected return on assets	**7.75%**	8.00%	8.00%
Rate of compensation increase	**4.23%**	4.23%	4.25%

	OPEB Costs		
	2015	**2014**	**2013**
Discount rate	**4.00%**	4.65%	3.96%
Expected return on assets	**7.75%**	8.00%	8.00%
Assumed medical cost trend rate (Pre 65/Post 65)	**6.00%**	6.50%	7.00%
Ultimate trend rate	**5.00%**	5.00%	5.00%
Year ultimate trend rate is reached	**2023**	2019	2019

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 2016, 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 our health care plans. For the year ended December 31, 2015, 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	**$ 6.5**	**$ (5.2)**
Effect on the health care component of the accumulated postretirement benefit obligation	**48.6**	**(40.3)**

Plan Assets

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

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

Central to the policy are target allocation ranges by major asset categories. The objectives of the target allocations are to maintain investment portfolios that diversify risk through prudent asset allocation parameters and to achieve asset returns that meet or exceed the plans' actuarial assumptions and that are competitive with like instruments employing similar investment strategies. The portfolio diversification provides protection against significant concentrations of risk in the plan assets. In 2014, the pension plan target asset allocation was 70% equity securities and 30% fixed income securities. In December 2014, we changed the pension plan target asset allocation to 60% equity securities and 40% fixed income securities for 2015. The target asset allocation for OPEB plans that have significant assets is 70% equity securities and 30% fixed income securities. Equity securities primarily include investments in large-cap and small-cap companies. Fixed income securities primarily include corporate bonds of companies from diversified industries, United States government securities, and mortgage-backed securities.

Pension and OPEB plan investments are recorded at fair value. See Note 1(q), 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, 2015							
	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	**$ —**	**$ 50.9**	**$ —**	**$ 50.9**	**$ 8.3**	**$ 1.1**	**$ —**	**$ 9.4**
Equity securities:								
United States Equity	**72.8**	**301.4**	**—**	**374.2**	**17.0**	**115.5**	**—**	**132.5**
International equity	**74.9**	**333.3**	**—**	**408.2**	**16.5**	**110.9**	**—**	**127.4**
Fixed income securities: [1]								
United States Bonds	**11.8**	**405.7**	**—**	**417.5**	**114.9**	**—**	**—**	**114.9**
International Bonds	**—**	**103.8**	**—**	**103.8**	**—**	**—**	**—**	**—**
	159.5	**1,195.1**	**—**	**1,354.6**	**156.7**	**227.5**	**—**	**384.2**
401(h) other benefit plan assets invested as pension assets [2]	**(5.5)**	**(41.1)**	**—**	**(46.6)**	**5.5**	**41.1**	**—**	**46.6**
Total [3]	**$ 154.0**	**$ 1,154.0**	**$ —**	**$ 1,308.0**	**$ 162.2**	**$ 268.6**	**$ —**	**$ 430.8**

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

(2) Pension trust assets are used to pay other postretirement benefits as allowed under Internal Revenue Code Section 401(h).

(3) Investments do not include accruals or pending transactions that are included in the table reconciling the change in fair value of plan assets.

	December 31, 2014							
	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	$ 0.5	$ 43.0	$ —	$ 43.5	$ 6.3	$ 2.6	$ —	$ 8.9
Equity securities:								
United States Equity	90.6	336.2	—	426.8	20.5	122.8	—	143.3
International equity	92.4	383.9	—	476.3	18.7	117.8	—	136.5
Fixed income securities: [1]								
United States Bonds	70.2	445.0	—	515.2	114.4	—	—	114.4
International Bonds	—	75.7	—	75.7	—	—	—	—
	253.7	1,283.8	—	1,537.5	159.9	243.2	—	403.1
401(h) other benefit plan assets invested as pension assets [2]	(7.4)	(37.2)	—	(44.6)	7.4	37.2	—	44.6
Total [3]	$ 246.3	$ 1,246.6	$ —	$ 1,492.9	$ 167.3	$ 280.4	$ —	$ 447.7

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

(2) Pension trust assets are used to pay other postretirement benefits as allowed under Internal Revenue Code Section 401(h).

(3) Investments do not include accruals or pending transactions that are included in the table reconciling the change in fair value of plan assets.

The following table sets forth a reconciliation of changes in the fair value of pension plan assets categorized as Level 3 in the fair value hierarchy during 2014. There was no level 3 activity in 2015.

(in millions)	United States Bonds	International Bonds	Total
Beginning balance at January 1, 2014	$ 1.3	$ 2.4	$ 3.7
Sales	(1.3)	(2.4)	(3.7)
Ending balance at December 31, 2014	$ —	$ —	$ —
Net unrealized gains (losses) related to assets still held at the end of the period	$ —	$ —	$ —

Cash Flows

We expect to contribute $15.7 million to the pension plans and $6.6 million to OPEB plans in 2016, dependent on various factors affecting us, including our liquidity position and possible tax law changes.

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

(in millions)	Pension Costs	OPEB Costs
2016	$ 196.3	$ 24.1
2017	105.9	26.3
2018	104.2	28.3
2019	116.4	30.6
2020	120.4	32.6
2021 through 2025	615.1	181.4

Savings Plans

WEC Energy Group maintains a 401(k) Savings Plan for substantially all of our full-time employees. A percentage of employee contributions are matched through an employee stock ownership plan (ESOP) contribution up to certain limits. Certain union employees receive a contribution to their ESOP account regardless of their participation in the 401(k) Savings Plan. Certain employees participate in a defined contribution pension plan, in which amounts are contributed to an employee's account based on the employee's wages, age, and years of service. Total costs incurred under all of these plans was $33.8 million in 2015, $35.0 million in 2014, and $36.4 million in 2013.

Deferred Compensation Plans

WEC Energy Group maintains deferred compensation plans that enable certain key employees to defer payment of a portion of their compensation on a pre-tax basis. The deferred compensation obligation classified within other long-term liabilities on our balance sheets was $97.6 million at December 31, 2015, and $64.4 million at December 31, 2014. The increase in the liability was driven by the WEC Merger. As a result of the merger, the portion of the deferred compensation obligation previously classified as an equity instrument was reclassified to a liability as all future distributions will be paid in cash.

The deferred compensation liability is adjusted, with a charge or credit to expense, to reflect changes in its fair value. The costs incurred under this arrangement were not significant in 2015, and were $9.5 million and $6.5 million in 2014 and 2013, respectively.

NOTE 20—COMMITMENTS AND CONTINGENCIES

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

Unconditional Purchase Obligations

Energy Related Purchased Power Agreements

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

The following table shows our minimum future commitments related to these purchase obligations as of December 31, 2015, including those of our subsidiaries.

(in millions)	Date Contracts Extend Through	Total Amounts Committed	Payments Due By Period 2016	2017	2018	2019	2020	Later Years
Electric utility:								
Purchased power	2027	$ 732.6	$ 85.5	$ 53.5	$ 56.2	$ 57.5	$ 59.8	$ 420.1
Coal supply and transportation	2019	198.4	97.3	46.5	43.5	11.1	—	—
Natural gas utility supply and transportation	2028	575.1	185.0	141.9	86.0	56.6	41.6	64.0
Total		$ 1,506.1	$ 367.8	$ 241.9	$ 185.7	$ 125.2	$ 101.4	$ 484.1

Operating Leases

We lease various property, plant, and equipment with various terms in the operating leases. 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 $10.8 million, $14.7 million, and $11.2 million in 2015, 2014, and 2013, respectively.

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

Year Ending December 31	Payments *(in millions)*
2016	$ 4.9
2017	6.0
2018	5.7
2019	4.8
2020	4.4
Later years	43.5
Total	$ 69.3

Environmental Matters

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

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 new 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 plants and conversion to modern, efficient, natural gas generation and super-critical pulverized coal 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 Air Ambient 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 latitude in rule implementation. States have the option of modeling or monitoring to show attainment (subject to EPA approval for this selection) and make attainment designation recommendations. If a state chooses modeling and an area does not show attainment, and sources do not agree to reductions by 2017 to allow attainment, the area would be classified as nonattainment. A plan would need to be developed requiring emission reductions to bring the area back into attainment by 2023. Alternatively, if a state opted out of modeling and instead chose to install air quality monitors, and subsequently monitored nonattainment, then it would face a 2026 compliance date. 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 March 2015, a federal court entered a consent decree between the EPA and the Sierra Club and others agreeing to specific actions related to implementing the revised standard for areas containing large sources emitting above a certain threshold level of SO_2. The consent decree requires the EPA to complete attainment designations for certain areas with large sources by no later than July 2, 2016.

We believe our fleet overall is well positioned to meet the new regulation.

8-Hour Ozone National Air Ambient Quality Standards

The EPA completed its review of the 2008 8-hour ozone standard in November 2014, and announced a proposal to tighten (lower) the NAAQS. In October 2015, the EPA released the final rule, which lowered the limit for ground-level ozone. This is expected to cause nonattainment designations for some counties in Wisconsin with potential future impacts for our fossil-fueled power plant fleet. For nonattainment areas, the state 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 and are in the process of reviewing and determining potential impacts resulting from this rule.

Mercury and Other Hazardous Air Pollutants

In December 2011, the EPA issued the final MATS rule, which imposes stringent limitations on emissions of mercury and other hazardous air pollutants from coal and oil-fired electric generating units beginning in April 2015. In addition, Wisconsin has a state mercury rule that requires a 90% reduction of mercury; however, this rule is not in effect as long as MATS is in place. In June 2015, the United States Supreme Court (Supreme Court) ruled on a challenge to the MATS rule and remanded the case back to the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court of Appeals), ruling that the EPA failed to appropriately consider the cost of the regulation. The MATS rule has been remanded to the EPA to address the Supreme Court decision, but remains in effect while the EPA completes its cost evaluation.

Our compliance plans currently include capital projects for WPS's jointly owned plants to achieve the required reductions for MATS. Construction of the ReACT™ multi-pollutant control system at Weston Unit 3 is complete and startup/commissioning work is underway with an expected in-service date of July 2016. Controls for acid gases and mercury are already in operation at the Pulliam units.

Although WPS received a one year MATS compliance extension from the WDNR for Weston Unit 3 through April 2016, this unit is on a planned outage to complete the construction of the ReACT™ system.

Climate Change

In 2015, the EPA issued the Clean Power Plan, a final rule regulating GHG emissions from existing generating units, a proposed federal plan as an alternative to state compliance plans, and final performance standards for modified and reconstructed generating units and new fossil-fueled power plants. The final rule for existing fossil generating units seeks to achieve state-specific GHG emission reduction goals by 2030, and requires states to submit plans by September 6, 2016. States submitting initial plans and requesting an extension would be required to submit final plans by September 2018, either alone or in conjunction with other states. States will be required to meet interim goals over the period from 2022 through 2029, and a final goal in 2030, with the goal of reducing nationwide GHG emissions by 32% from 2005 levels. The rule is seeking GHG emission reductions in Wisconsin of 41% below 2012 levels by 2030. The building blocks used by the EPA to determine each state's emission reduction requirements include a combination of improving power plant efficiency, increasing reliance on combined cycle natural gas units, and adding new renewable energy resources.

Rules for existing, as well as new, modified, and reconstructed generating units became effective in October 2015. A draft Federal Plan and Model Trading Rule were also published in October 2015 for use in developing state plans or for use in states where a plan is not submitted or approved. In December 2015, the state of Wisconsin submitted petitions for review to the EPA of the final standards for existing as well as new, modified, and reconstructed generating units. A petition for review was also submitted jointly by the Wisconsin utilities. The utilities' petition narrowly asks the EPA to consider revising the state goal for existing units to reflect the 2013 retirement of the Kewaunee Power Station, which could lower the state's CO_2 equivalent reduction goal by about 10%. The state's petition asks for review of a number of aspects of the final rules, including an adjustment to reflect the Kewaunee Power Station retirement. In January 2016, we submitted comments on the draft Federal Plan and Model Trading Rule.

We are in the process of reviewing the final rule for existing generating units to determine the potential impacts to our operations. The rule could result in significant additional compliance costs, including capital expenditures, could impact how we operate our existing fossil-fueled power plants, and could have a material adverse impact on our operating costs. In October 2015, following publication of the final rule, numerous states (including Wisconsin), trade associations, and private 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 on February 9, 2016, the Supreme Court stayed the effectiveness of the rule until disposition of the litigation in the D.C. Circuit Court of Appeals and to the extent that review is sought, at the Supreme Court. Therefore, it is unlikely that states will move forward on the development of state plans until the litigation is complete. In addition, on February 15, 2016, the Governor of Wisconsin issued Executive Order 186, which prohibits state agencies, departments, boards, commissions, or other state entities from developing or promoting the development of a state plan.

We are required to report our CO_2 equivalent emissions from our electric generating facilities under the EPA Greenhouse Gases Reporting Program. For 2014, we reported aggregated CO_2 equivalent emissions of approximately 6.2 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 2015. The level of CO_2 and other GHG emissions vary from year to year and are 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 2014, we reported aggregated CO_2 equivalent emissions of approximately 20.1 million metric tonnes to the EPA related to our distribution and sale of natural gas. Based upon our preliminary analysis of the data, we estimate that we will report CO_2 equivalent emissions of approximately 17.7 million metric tonnes to the EPA for 2015.

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 and entrainment. 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 evaluate the available IM options for Pulliam Units 7 and 8. We also expect that limited studies will be required to support the future WDNR BTA determinations for Weston Unit 2. Based on preliminary discussions with the WDNR, we anticipate that the WDNR will not require physical modifications to the Weston Unit 2 intake structure to meet the IM BTA requirements based on low capacity use of the unit.

BTA determinations must also be made by the WDNR to address entrainment mortality (EM) reduction on a site-specific basis taking into consideration several factors. BTA determinations for EM will be made in future permit reissuances for Pulliam Units 7 and 8 and Weston Units 2 through 4.

During 2016–2018, we plan to complete studies and evaluate options to address the EM BTA requirements at our plants. With the exception of Weston Units 3 and 4 (which all have existing cooling towers that meet EM BTA requirements), we cannot yet determine what, if any, intake structure or operational modifications will be required to meet the new EM BTA requirements at our facilities. We also expect that limited studies to support WDNR BTA determinations will be conducted at the Weston facility. Based on preliminary discussions with the WDNR, we anticipate that the WDNR will not require physical modifications to the Weston Unit 2 intake structure to meet the EM BTA requirements based on low capacity use of the unit. Entrainment studies are currently being conducted at Pulliam Units 7 and 8.

Steam Electric Effluent Guidelines

The EPA's final steam electric effluent guidelines rule took effect in January 2016 and applies to discharges of wastewater from our power plant processes in Wisconsin. Unless pending challenges to the final guidelines are successful, the WDNR will modify the state rules and incorporate the new requirements into our facility permits, which are renewed every five years. We expect the new requirements to be phased in between 2018 and 2023 as our permits are renewed. Our power plant facilities already have advanced wastewater treatment technologies installed that meet many of the discharge limits established by this rule. However, these standards will require additional wastewater treatment retrofits as well as installation of other equipment to minimize process water use. The final rule phases in new or more stringent requirements related to limits of arsenic, mercury, selenium, and nitrogen in wastewater discharged from wet scrubber systems. The rule also requires dry fly ash handling, which is already in place at all of our power plants. Dry bottom ash transport systems are also required by the new rule, and modifications will be required at Pulliam Units 7 and 8 and Weston Unit 3. We are beginning preliminary engineering for compliance with the rule and estimate a total cost range of $10 million to $20 million for these bottom ash transport systems.

Land Quality

Coal Combustion Residuals Rule

In April 2015, the Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities final rule was entered into the Federal Register. The final rule regulates the disposal of coal combustion residuals as a non-hazardous waste. We do not expect the compliance costs will be significant because we currently have a program of beneficial utilization for most of our coal combustion products. If needed, we have landfill capacity that meets the rule requirements for our remaining coal combustion product sources.

Coal Combustion Product Landfill Sites

We aggressively seek environmentally acceptable, beneficial uses for our coal combustion products. However, some coal combustion products have been, and to a small degree continue to be, managed in company-owned, licensed landfills. Some early designed and constructed landfills have at times required some level of monitoring or remediation. Where we have become aware of these conditions, and where necessary, we have worked to define the nature and extent of the impact, if any, and work has been performed to address these conditions. During 2015, 2014, and 2013, landfill remediation expenses were not material. See Note 11, Asset Retirement Obligations, for more information about obligations related to these sites.

Renewables, Efficiency, and Conservation

Wisconsin Act 141

In 2006, Wisconsin revised the requirements for renewable energy generation by enacting Act 141. Act 141 established a goal that 10% of all electricity consumed in Wisconsin be generated by renewable resources by December 31, 2015. Under Act 141, WPS is required to increase their renewable energy percentage to 9.74%. To comply with these requirements, WPS constructed the Crane Creek wind park. WPS also relies on renewable energy purchases to meet their respective renewable portfolio standard commitments.

WPS is in compliance with Act 141's 2015 standard and have entered into agreements for renewable energy credits, that should allow them to remain in compliance through 2022 and 2023, respectively. If market conditions are favorable, WPS may purchase more renewable energy credits. Act 141 assigned responsibility for the administration of energy efficiency, conservation, and renewable programs to the PSCW and/or contracted third parties. The funding required by Act 141 for 2015 was 1.2% of WPS's annual operating revenues.

Manufactured Gas Plant Remediation

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

In addition, some of these sites are coordinating the investigation and cleanup 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)	2015	2014
Regulatory assets	**$ 654.0**	$ 634.3
Reserves for future remediation	**598.0**	579.7

Enforcement and Litigation Matters

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

Weston Title V Air Permit

In August 2013, the WDNR issued the Weston Title V air permit. In September 2013, WPS challenged various requirements in the permit by filing a contested case proceeding with the WDNR and also filed a Petition for Judicial Review in the Brown County Circuit Court. The Sierra Club and Clean Wisconsin also challenged various aspects of the permit. The WDNR granted all parties' requests for contested case proceedings. The Petitions for Judicial Review, by all parties, have been stayed pending the resolution of the contested cases. In February 2014, a new permit change was challenged and added to the case. The ALJ dismissed some of the petition issues relating to the averaging period and monitoring issues.

In May 2014, the WDNR issued a Notice of Violation (NOV) alleging that WPS failed to maintain a minimum sorbent feed rate prior to the Continuous Emissions Monitoring System certification and included an issue related to reporting NOx emissions from the Weston Unit 4 auxiliary boiler.

In June 2015, the WDNR issued a NOV alleging that WPS failed to comply with mercury reporting requirements related to challenged matters in the 2013 Weston Title V permit. The ALJ denied its request to issue a stay or confirm that a statutory stay applies to the requirements identified in the NOV.

The contested case has been stayed for a period of months, and no hearing date has been set. We do not expect these matters to have a material impact on our financial statements.

Consent Decrees

Wisconsin Public Service Corporation Consent Decree – Weston and Pulliam

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

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

As mentioned above, the Consent Decree contains a requirement 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 and recorded a regulatory asset of $11.5 million for the undepreciated book value. WPS received approval from the PSCW in its 2015 rate order to defer and amortize the undepreciated book value of the retired plant associated with these units starting June 1, 2015, and concluding by 2023.

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. The majority of the beneficial environmental projects proposed by WPS have been approved by the EPA. WPS is currently working with the EPA on certain changes to the environmental projects, but these changes are not expected to materially impact the overall cost.

Also, in May 2010, WPS received from the Sierra Club a Notice of Intent to file a civil lawsuit based on allegations that WPS violated the CAA at the Weston and Pulliam plants. WPS entered into a Standstill Agreement with the Sierra Club by which the parties agreed to negotiate as part of the EPA NOV process, rather than litigate. The Standstill Agreement ended in October 2012, but no further action has been taken by the Sierra Club as of December 31, 2015. It is unknown whether the Sierra Club will take further action in the future.

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, Wisconsin Electric (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, Wisconsin Power and Light, Madison Gas and Electric, and Wisconsin Electric 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. Wisconsin Electric paid an immaterial portion of the assessed penalty but has no further obligations under the Consent Decree. The final Consent Decree includes:

- the installation of emission control technology, including scrubbers at the Columbia plant,
- changed operating conditions (including refueling, repowering, and/or retirement of units),
- limitations on plant emissions,
- beneficial environmental projects, with WPS's portion totaling $1.3 million, and

- WPS's portion of a civil penalty and legal fees totaling $0.4 million.

As mentioned above, the Consent Decree contains a requirement to refuel, repower, or retire Edgewater Unit 4, of which WPS is a joint owner, by no later than December 31, 2018. In the first quarter of 2015, management of the joint owners recommended that Edgewater Unit 4 be retired in December 2018. However, a final decision on how to address the requirement for this unit has not yet been made by the joint owners, as early retirement is contingent on various operational and market factors, and other alternatives to retirement are still available. All of the beneficial environmental projects that WPS proposed have been approved by the EPA.

NOTE 21—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, 2015			
(in millions)	Level 1	Level 2	Level 3	Total
Assets				
Derivative assets				
Natural gas contracts	**$ 0.5**	**$ 1.2**	**$ —**	**$ 1.7**
FTRs	**—**	**—**	**2.0**	**2.0**
Total derivative assets	**$ 0.5**	**$ 1.2**	**$ 2.0**	**$ 3.7**
Investments held in rabbi trust	**$ 39.8**	**$ —**	**$ —**	**$ 39.8**
Liabilities				
Derivative liabilities				
Natural gas contracts	**$ 2.8**	**$ 24.7**	**$ —**	**$ 27.5**
Petroleum products contracts	**0.5**	**—**	**—**	**0.5**
Coal contracts	**—**	**4.7**	**—**	**4.7**
Total derivative liabilities	**$ 3.3**	**$ 29.4**	**$ —**	**$ 32.7**

	December 31, 2014			
(in millions)	Level 1	Level 2	Level 3	Total
Assets				
Derivative assets				
Natural gas contracts	$ —	$ 2.3	$ —	$ 2.3
FTRs	—	—	2.2	2.2
Total derivative assets	$ —	$ 2.3	$ 2.2	$ 4.5
Investments held in rabbi trust	$ 102.4	$ —	$ —	$ 102.4
Liabilities				
Derivative liabilities				
Natural gas contracts	$ 4.8	$ 31.2	$ 6.6	$ 42.6
FTRs	—	—	0.3	0.3
Petroleum products contracts	2.8	—	—	2.8
Coal contracts	—	1.2	2.2	3.4
Total derivative liabilities	$ 7.6	$ 32.4	$ 9.1	$ 49.1

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 22, 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)	2015	2014	2013
Balance at the beginning of the period	**$ (6.9)**	$ (1.3)	$ (5.4)
Realized and unrealized (losses) gains	**(10.7)**	(7.6)	3.3
Purchases	**9.8**	4.3	3.2
Sales	**(0.1)**	—	(0.2)
Settlements	**5.2**	(3.5)	(2.2)
Transfers out of Level 3	**4.7**	1.2	—
Balance at the end of the period	**$ 2.0**	$ (6.9)	$ (1.3)

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

Fair Value of Financial Instruments

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

	2015		2014	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	**$ 3,169.9**	**$ 3,233.1**	$ 3,049.7	$ 3,271.4
Preferred stock *	**—**	**—**	51.1	51.8

* On November 13, 2015, WPS redeemed all of its outstanding shares of preferred stock. See Note 14, Preferred Stock, for more information.

NOTE 22—DERIVATIVE INSTRUMENTS

The following tables show our derivative assets and derivative liabilities:

		December 31, 2015		December 31, 2014	
(in millions)	Balance Sheet Presentation	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Natural gas contracts	Other current	**$ 1.2**	**$ 25.6**	$ 1.8	$ 37.3
Natural gas contracts	Other long-term	**0.5**	**1.9**	0.5	5.3
Petroleum products contracts	Other current	**—**	**0.5**	—	2.7
Petroleum products contracts	Other long-term	**—**	**—**	—	0.1
FTRs	Other current	**2.0**	**—**	2.2	0.3
Coal contracts	Other current	**—**	**3.3**	—	2.4
Coal contracts	Other long-term	**—**	**1.4**	—	1.0
	Other current	**3.2**	**29.4**	4.0	42.7
	Other long-term	**0.5**	**3.3**	0.5	6.4
Total		**$ 3.7**	**$ 32.7**	$ 4.5	$ 49.1

Our estimated notional volumes and gains (losses) were as follows:

	December 31, 2015		December 31, 2014		December 31, 2013	
(in millions)	Volume	Gains (Losses)	Volume	Gains (Losses)	Volume	Gains (Losses)
Natural gas contracts	85.2 Dth	**$ (55.0)**	76.9 Dth	$ 8.0	76.3 Dth	$ (16.0)
Petroleum products contracts	7.9 gallons	**(3.4)**	7.3 gallons	(0.5)	4.7 gallons	(0.3)
FTRs	9.0 MWh	**3.3**	8.7 MWh	3.2	9.1 MWh	5.1
Total		**$ (55.1)**		$ 10.7		$ (11.2)

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

	December 31, 2015		December 31, 2014	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Gross amount recognized on the balance sheet	**$ 3.7**	**$ 32.7**	$ 4.5	$ 49.1
Gross amount not offset on the balance sheet *	**(1.7)**	**(4.5)**	(1.3)	(8.8)
Net amount	**$ 2.0**	**$ 28.2**	$ 3.2	$ 40.3

* Includes cash collateral posted of $2.8 million and $7.5 million as of December 31, 2015 and 2014, respectively.

As of December 31, 2015 and 2014, we posted collateral of $21.8 million and $11.6 million, respectively, in our margin accounts. Certain of our derivative and non-derivative commodity instruments contain provisions that could require "adequate assurance" in the event of a material change in our creditworthiness, or the posting of additional collateral for instruments in net liability positions, if triggered by a decrease in credit ratings. 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, 2015 and 2014, was $23.8 million and $31.3 million, respectively. At December 31, 2015 and 2014, 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, 2015 and 2014, we would have been required to post collateral of $18.0 million and $27.1 million, respectively.

NOTE 23—REGULATORY ENVIRONMENT

Wisconsin Public Service Corporation

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%). Based on the order, the PSCW will continue to allow escrow treatment for ATC and MISO network transmission expenses through 2016. In addition, future system support resource payments will continue to be escrowed until a future rate proceeding. This allows 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 requires 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.

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 10.20% ROE. The order authorized a common equity component average of 50.28%. The PSCW approved a change in rate design for WPS, which includes 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 $42.0 million. In addition, 2015 rates included approximately $9.0 million of lower refunds to customers related to decoupling over-collections. In 2015 rates, WPS refunded approximately $4.0 million to customers related to 2013 decoupling over-collections compared with refunding approximately $13.0 million to customers in 2014 rates related to 2012 decoupling over-collections. Absent these adjustments for electric fuel costs and decoupling refunds, WPS would have realized an electric rate decrease. 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 20, Commitments and Contingencies, for more information. The PSCW is allowing WPS to escrow ATC and MISO network transmission expenses for 2015 and 2016. As a result, WPS defers as a regulatory asset or liability the differences 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 $16.0 million year-over-year negative impact of decoupling refunds to and collections from customers. In 2015 rates, WPS refunded approximately $8.0 million to customers related to 2013 decoupling over-collections compared with recovering approximately $8.0 million from customers in 2014 rates related to 2012 decoupling under-collections. Absent the adjustment for decoupling refunds to and collections from customers, WPS would have realized a retail natural gas rate increase.

2014 Wisconsin Rate Order

In March 2013, we initiated a rate proceeding with the PSCW. In December 2013, the PSCW issued a final written order for WPS, effective January 1, 2014. It authorized a net retail electric rate decrease of $12.8 million and a net retail natural gas rate increase of $4.0 million, reflecting a 10.20% ROE. The order also included a common equity component average of 50.14%. The retail electric rate impact consisted of a rate increase, including recovery of the difference between the 2012 fuel refund and the 2013 rate increase discussed below, entirely offset by a portion of estimated fuel cost over-collections from customers in 2013. Retail electric rates were further decreased by 2012 decoupling over-collections to be returned to customers in 2014. The retail natural gas rate impact consisted of a rate decrease, which was more than offset by the positive impact of 2012 decoupling under-collections of approximately $8.0 million to be recovered from customers in 2014. Both the retail electric and retail natural gas rate changes included the recovery of pension and other employee benefit increases that were deferred in the 2013 rate case, as discussed below. The PSCW also authorized the recovery of prudently incurred 2014 environmental mitigation project costs related to compliance with a Consent Decree signed in January 2013 for the Pulliam and Weston sites. See Note 20, Commitments and Contingencies, for more information. Additionally, the order required WPS to terminate its decoupling mechanism, beginning January 1, 2014.

2013 Wisconsin Rate Order

In March 2012, we initiated a rate proceeding with the PSCW. In December 2012, the PSCW issued a final written order for WPS, effective January 1, 2013. The order included a $28.5 million retail electric rate increase, partially offset by the actual 2012 fuel refund of $20.5 million. The difference between the 2012 fuel refund and the rate increase was deferred for recovery in 2014 rates. As a result, there was no change to customers' 2013 retail electric rates. The order also included a $3.4 million retail natural gas rate decrease. The order reflected a 10.30% ROE and a common equity component average of 51.61%. The rate changes included deferrals of $7.3 million for retail electric and $2.1 million for retail natural gas of pension and other employee benefit costs that are being recovered in 2014 rates. In addition, WPS was authorized recovery of $5.9 million related to income tax amounts previously expensed due to the Federal Health Care Reform Act. As a result, this amount was recorded as a regulatory asset in 2012, and recovery from customers began in 2013. The order also authorized the recovery of direct Cross State Air Pollution Rule costs incurred through the end of 2012. Lastly, the order authorized WPS to switch from production tax credits to Section 1603 Grants for the Crane Creek wind project.

A decoupling mechanism for natural gas and electric residential and small commercial and industrial customers was approved on a pilot basis as part of the order. The mechanism was based on total rate case-approved margins, rather than being calculated on a per-customer basis. The mechanism did not cover all customer classes, and it included an annual $14.0 million cap for electric service and an annual $8.0 million cap for natural gas service. Amounts recoverable from or refundable to customers were subject to these caps.

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 reflect a 10.2% ROE and a common equity component average of 50.48%. The increase reflects the continued deferral of costs associated with the Fox Energy Center until the second anniversary of the order. The increase also reflects the deferral of Weston Unit 3 ReACT™ environmental project costs. On the second anniversary of the order, WPS will discontinue the deferral of Fox Energy Center costs and will begin 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. Lastly, WPS will not seek an increase to retail electric base rates that would become effective prior to January 1, 2018.

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 merger.

Illinois Investigations

In March 2015, the ICC opened a docket, naming PGL as respondent, to investigate the veracity of certain allegations included in anonymous letters that the ICC staff received regarding the AMRP. The Illinois Attorney General's (AG's) office is also conducting an inquiry into the same allegations. Since the investigations are ongoing, it is too early to determine what effect, if any, the investigations will have on the AMRP. In July 2015, we engaged a nationally recognized engineering and construction firm to conduct an independent, bottom up review of the AMRP's long-term cost, scope, and schedule. We filed the results of that review with the ICC on November 30, 2015.

In November 2015, the ICC initiated an investigation into whether we, PGL, or WEC Energy Group knowingly misled or withheld material information from the ICC at its open meeting on May 20, 2015. The investigation relates to the ICC Staff's presentation of the independent audit findings reached for the AMRP. The AG's office is conducting an inquiry into this matter as well. It is too early to estimate the outcome of these inquiries since they are ongoing.

In December 2015, the ICC ordered a series of stakeholder workshops to evaluate the AMRP. This ICC action does not impact PGL's ongoing work to modernize and maintain the safety of its natural gas distribution system, but it instead provides the ICC with an opportunity to analyze long-term elements of the program through the stakeholder workshops. The workshops are expected to result in an ICC order with final and binding recommendations for the AMRP. Since the workshops only commenced in January 2016, we are currently unable to determine what, if any, long-term impact there will be on the AMRP.

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 reflect a 9.05% ROE and a common equity component average of 50.33%. The rates for NSG reflect 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, PGL recovers a return on certain investments and depreciation expense through the qualifying infrastructure plant rider discussed below, and accordingly, such costs are not subject to PGL's rate order. In February 2015, the AG and certain intervenors filed requests for rehearing on certain issues, which the ICC denied in March 2015. No appeals were filed related to the rehearing requests.

Qualifying Infrastructure Plant Rider

In July 2013, Illinois Public Act 98-0057, The Natural Gas Consumer, Safety & Reliability Act, became law. The Act gives PGL a cost recovery mechanism for prudently incurred costs to upgrade Illinois natural gas infrastructure that are collected through a surcharge on customer bills. This Act eliminated a requirement for PGL and NSG to file biennial rate proceedings under existing Illinois coal-to-gas legislation. In September 2013, PGL filed with the ICC requesting the proposed rider, which was approved in January 2014 and became effective as of January 1, 2014.

2013 Illinois Rate Order

In July 2012, PGL and NSG initiated a rate proceeding with the ICC. In June 2013, the ICC issued a final written order for PGL and NSG, effective June 27, 2013. The order authorized a retail natural gas rate increase of $57.2 million for PGL and $6.6 million for NSG. The rates for PGL reflected a 9.28% ROE and a common equity component average of 50.43%. The rates for NSG reflected a 9.28% ROE and a common equity component average of 50.32%. The rate order also allowed PGL and NSG to continue the use of their decoupling mechanisms, as affirmed by the Illinois Supreme Court as discussed below.

In August 2013, the ICC granted certain rehearing requests on tax-related issues filed by PGL, NSG, and other intervenors. PGL and NSG asked for a correction of the revenue requirement for deferred tax assets related to tax net operating losses (NOLs) incurred in 2012 and 2013. In the ICC's order, these deferred tax assets were included in rate base, but computational errors were made. Other intervenors requested the exclusion from rate base of the deferred tax asset related to the 2012 tax NOL. The tax NOLs in question resulted from PGL and NSG claiming accelerated depreciation deductions in 2012 and 2013. In December 2013, the ICC evaluated and approved a correction of the computational errors and rejected the intervenors' proposed exclusion of the 2012 tax NOL. Customer rates were increased by $2.6 million for PGL and $0.1 million for NSG for the impact of this correction, effective January 1, 2014. In January 2014, the AG and Citizens Utility Board each filed an appeal with the Illinois Appellate Court (Court). In April 2015, the Citizens Utility Board appeal was withdrawn, and, in May 2015, the Court dismissed the appeal from the AG.

2012 Decoupling

The ICC issued a final written order, effective January 21, 2012, which approved a permanent decoupling mechanism for PGL and NSG. The AG and Citizens Utility Board appealed to the Court the ICC's authority to approve PGL's and NSG's decoupling mechanisms and filed a motion to stay the implementation of the permanent decoupling mechanisms or make collections subject to refund. In May 2012, the ICC issued a revised amendatory order granting the AG's motion to make revenues collected under the permanent decoupling mechanisms subject to refund. Refunds would have been required if the Court found that the ICC did not have authority to approve decoupling and ordered a refund. As a result, the recovery of amounts related to decoupling in 2012 were uncertain, and PGL and NSG established offsetting reserves equal to decoupling amounts accrued. In March 2013, the Court issued an opinion that affirmed the ICC's order approving the permanent decoupling mechanisms. As a result, the reserves recorded in 2012 were reversed in the first quarter of 2013. PGL's and NSG's permanent decoupling mechanism was in place for 2013. In June 2013, the AG and Citizens Utility Board petitioned the Illinois Supreme Court to appeal the Court's decision. In January 2015, the Illinois Supreme Court affirmed the ICC's authority to approve the permanent decoupling mechanism. As a result, decoupling amounts recorded in 2014 were refunded to customers in 2015 as planned, and decoupling amounts in the future will continue to be accrued.

Minnesota Energy Resources Corporation

2016 Minnesota Rate Case

In September 2015, MERC initiated a rate proceeding with the MPUC to increase retail natural gas rates $14.8 million (5.5%). MERC's request reflects a 10.3% ROE and a common equity component average of 50.32%. The proposed retail natural gas rate increase is primarily driven by higher construction and capital expenditures, general inflation, and improvements to customer service programs. The request also includes increases in costs related to the acquisition of Alliant Energy Corporation's Minnesota natural gas operations in April 2015. MERC is requesting authority from the MPUC to continue the use of its currently authorized decoupling mechanism.

In November 2015, the MPUC approved an interim rate order, effective January 1, 2016, authorizing a retail natural gas rate increase for MERC of $9.7 million (3.7%). The interim rates reflect a 9.35% ROE and a common equity component average of 50.32%. The interim rate increase is subject to refund pending the final rate order.

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 reflect 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 will be requested in a future rate case. A decoupling mechanism with a 10% cap remains in effect for MERC's 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.

2011 Minnesota Rate Order Finalized in 2013

In November 2010, MERC initiated a rate proceeding with the MPUC. In July 2012, the MPUC approved a final written order for MERC, effective January 1, 2013. The order authorized a retail natural gas rate increase of $11.0 million. The rates reflected a 9.70% ROE and a common equity component average of 50.48%. In addition, the order sets recovery of MERC's 2011 test-year pension expense at 2010 levels. The MPUC also approved a decoupling mechanism for MERC that covers residential and small commercial and industrial customers on a three-year trial basis, effective January 1, 2013. The decoupling mechanism does not adjust for variations in volumes resulting from changes in customer count compared to rate case levels. It includes an annual 10% cap based on distribution revenues approved in the rate case. Amounts recoverable from or refundable to customers are subject to this cap.

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 is in effect in 2016, MGU is required to establish a regulatory liability for the resulting cost savings and must refund the liability in its next general rate case.

2014 Michigan Rate Order

In June 2013, MGU initiated a rate proceeding with the MPSC. In November 2013, the MPSC issued a final written order for MGU, effective January 1, 2014. The order authorized a retail natural gas rate increase of $4.5 million. The rates reflect a 10.25% ROE and a common equity component average of 48.62%. Additionally, the order required MGU to terminate its decoupling mechanism after December 31, 2013 and replace it with a new decoupling mechanism based on total margins, beginning January 1, 2015. The new decoupling mechanism does not cover variations in volumes due to actual weather being different from rate case-assumed weather. The rate order also terminated MGU's uncollectible expense true-up mechanism after December 31, 2013.

Depreciation Case

In January 2013, the Michigan Court of Appeals issued an order reversing the MPSC's 2010 disallowance of $2.5 million associated with the early retirement of certain MGU assets. As a result, a $2.5 million reduction to depreciation expense was recorded in the first quarter of 2013. In June 2013, the MPSC issued an order related to MGU's most recent depreciation case. This order also approved a settlement agreement reflecting recovery of these previously disallowed costs.

Upper Peninsula Power Company

2014 Michigan Rate Order

In June 2013, UPPCO initiated a rate proceeding with the MPSC. In December 2013, the MPSC issued a final written order for UPPCO, effective January 1, 2014. The order authorized a retail electric rate increase of $5.8 million. The rates reflected a 10.15% ROE and a common equity component average of 56.74%. The order required UPPCO to terminate its decoupling mechanism after December 31, 2013. In addition, the order required UPPCO to achieve certain minimum line clearance performance metrics for recovery of costs related to clearing trees and other natural obstructions away from power lines.

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, 2013	$ (3.1)	$ (20.1)	$ (23.2)
Other comprehensive loss before reclassifications	—	(6.0)	(6.0)
Amounts reclassified out of accumulated other comprehensive loss	(0.1)	1.7	1.6
Net 2014 other comprehensive loss	(0.1)	(4.3)	(4.4)
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)**

NOTE 25—OTHER INCOME, NET

Total other income, net was as follows at December 31:

(in millions)	2015	2014	2013
Equity portion of AFUDC	**$ 17.7**	$ 12.5	$ 10.8
Federal excise tax credit	**7.3**	4.4	4.1
Key executive life insurance income for retired employees	**2.8**	2.9	2.2
Equity in earnings of investments, excluding ATC	**0.3**	2.6	2.4
Gain on sale of land at the holding company	**—**	3.5	—
(Losses) gains on exchange-traded funds	**(3.3)**	2.9	2.2
Other	**4.3**	5.7	2.7
Total other income, net	**$ 29.1**	$ 34.5	$ 24.4

NOTE 26—SEGMENT INFORMATION

We reorganized our business segments during the second quarter of 2015 to reflect our new internal organization and management structure. All prior period amounts impacted by this change were reclassified to conform to the new presentation. We use operating income to measure segment profitability and to allocate resources to our businesses. At December 31, 2015, we reported five segments, which are described below.

- The Wisconsin segment includes the electric and natural gas utility and non-utility operations of WPS, including its electric and natural gas operations in the state of Michigan.

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

- The other states segment includes the natural gas utility and non-utility operations of MERC and MGU, as well as the operations of UPPCO prior to its sale to Balfour Beatty Infrastructure Partners LP in August 2014. See Note 4, Dispositions, for more information on the sale of UPPCO.

- The electric transmission investment segment includes our approximate 34% ownership interest in ATC, a federally regulated electric transmission company.

- The corporate and other segment includes the operations of the Integrys holding company, the PELLC holding company, WBS, PDL, and ITF, as well as the discontinued operations of IES prior to its sale in November 2014. See Note 4, Dispositions, for more information on the sales of IES and ITF.

All of our operations and assets are located within the United States. The following tables show summarized financial information concerning our reportable segments for the years ended December 31, 2015, 2014, and 2013:

2015 *(in millions)*	Regulated Operations: Wisconsin	Regulated Operations: Illinois	Regulated Operations: Other States	Regulated Operations: Electric Transmission Investment	Regulated Operations: Total Regulated Operations	Corporate and Other	Reconciling Eliminations	Integrys Holding Consolidated
Income statement								
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**	**10.1**	**—**	**1,069.8**
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**
Gain on sale of certain PDL solar power generation plants, net of transaction costs	**—**	**—**	**—**	**—**	**—**	**(5.2)**	**—**	**(5.2)**
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**

2014 *(in millions)*	Regulated Operations: Wisconsin	Regulated Operations: Illinois	Regulated Operations: Other States	Regulated Operations: Electric Transmission Investment	Regulated Operations: Total Regulated Operations	Corporate and Other	Reconciling Eliminations	Integrys Holding Consolidated
Income statement								
External revenues	$ 1,668.4	$1,764.8	$ 617.4	$ —	$ 4,050.6	$ 95.0	$ —	$ 4,145.6
Other operation and maintenance	499.8	565.5	150.7	—	1,216.0	14.5	0.1	1,230.6
Depreciation and amortization	116.8	114.8	23.7	—	255.3	35.3	—	290.6
Merger costs	—	—	—	—	—	10.4	—	10.4
Gain on abandonment of PDL's Winnebago Energy Center	—	—	—	—	—	(5.0)	—	(5.0)
Gain on sale of UPPCO, net of transaction costs	—	—	(85.4)	—	(85.4)	—	—	(85.4)
Operating income (loss)	257.6	123.6	146.8	—	528.0	(21.8)	—	506.2
Equity in earnings of transmission affiliate	—	—	—	85.7	85.7	—	—	85.7
Interest expense	57.4	34.5	12.0	—	103.9	63.2	(12.3)	154.8
Capital expenditures	322.0	355.3	57.8	—	735.1	121.6	—	856.7
Total assets	4,205.2	5,055.3	880.8	536.7	10,678.0	993.0	(473.0)	11,198.0

	Regulated Operations							
2013 *(in millions)*	**Wisconsin**	**Illinois**	**Other States**	**Electric Transmission Investment**	**Total Regulated Operations**	**Corporate and Other**	**Reconciling Eliminations**	**Integrys Holding Consolidated**
Income statement								
External revenues	$ 1,557.7	$1,354.0	$ 530.3	$ —	$ 3,442.0	$ 44.7	$ —	$ 3,486.7
Other operation and maintenance	470.3	476.4	147.1	—	1,093.8	21.8	—	1,115.6
Depreciation and amortization	109.4	107.7	21.0	—	238.1	28.5	—	266.6
Operating income (loss)	240.0	156.3	67.2	—	463.5	(24.0)	—	439.5
Equity in earnings of transmission affiliate	—	—	—	89.1	89.1	—	—	89.1
Interest expense	43.7	32.4	12.7	—	88.8	51.5	(12.9)	127.4
Capital expenditures	236.1	294.7	55.9	—	586.7	75.4	—	662.1
Total assets	3,886.0	4,596.3	1,099.6	508.5	10,090.4	1,596.1	(507.1)	11,179.4

NOTE 27—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. This guidance is effective for fiscal years and interim periods beginning after December 15, 2018, and can either be applied retrospectively or as a cumulative-effect adjustment as of the date of adoption. We are currently assessing the effects this guidance may have on our financial statements.

Classification and Measurement of Financial Instruments

In January 2016, the FASB issued ASU 2016-01, Classification and Measurement of Financial Assets and Liabilities. This guidance is effective for fiscal years and interim periods beginning after December 15, 2018, and will be recorded with a cumulative-effect adjustment to beginning retained earnings as of the beginning of the fiscal year in which the guidance is effective. We are currently assessing the effects this guidance may have 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, 2019. We are currently assessing the effects this guidance may have on our financial statements.